

# **BULK POWER SYSTEMS DYNAMICS AND CONTROL – V SECURITY AND RELIABILITY IN A CHANGING ENVIRONMENT**

## **Symposium Proceedings**

**Edited by** L. H. Fink,  
C. D. Vournas,  
C. C. Liu,  
J. Kubokawa,  
**and** Y. Zoka

**Onomichi, Japan  
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**IREP2001: Onomichi**

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## **NOTICE**

Edited discussions are based on the editors' notes and their interpretation of the recognizable portions of the recorded discussions.

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# **BULK POWER SYSTEMS DYNAMICS AND CONTROL – V SECURITY AND RELIABILITY IN A CHANGING ENVIRONMENT**

## **IREP2001: Onomichi**

An International Symposium  
Onomichi, Japan  
26–31 August, 2001

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## Preface

The Symposium of which these Proceedings are the record was the eighth in a series on Power System Dynamics and Control, and the second under the auspices of IREP - the International Institute for Research and Engineering in Power System Dynamics. Since the first of these Symposia in 1972, the power system industry has been subjected to radical (some might say cataclysmic) reconstruction in the interests of "deregulation." This Symposium took place in the wake of the 2001 energy crisis in California, and this volume appears in the aftermath of the 2002 meltdown of the ENRON, the largest power marketer in the United States. ENRON had been the epitome of that new segment of the industry spawned by the breakup of the traditional regulated, vertically-integrated utilities.

The demise of ENRON, resulting from unregulated speculation in "derivatives," did not reflect any failure in power system engineering. Nevertheless, such a radical restructuring of a major industry necessarily poses unprecedented problems for that discipline, which, having reflected the former structure of the industry, must now be reinvented to accommodate a new structure which is not as yet fully defined. Responsibility for overall system performance, previously residing unambiguously on the regulated power companies serving their respective franchise loads, is now, inescapably, diffusing among the new collection of entities and is in danger of dissipating in new interstices.

Under these emerging conditions, can adequate, accountable, responsibilities for component requirements for reliability be allocated among industry members, and how can those responsible for overall system operation be assured of access to all the means (data and tools) necessary to guarantee continuance of an adequate level of performance? These questions involve not only the traditional engineering disciplines, but also those of market structure and operation treated by economists.

These Proceedings represent an attempt to tackle some of these problems.

IREP, and the worldwide power industry, are indebted to the Organizing Committee of our Japanese colleagues, to Hiroshima University, and to Onomichi City for their magnificent support of this Symposium, "IREP 2001."

*Lester H. Fink*  
January 2002

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**Session I:**  
**FUTURE-SYSTEMS & RELIABILITY**

Monday, August 27, 09:30–12:00

Chair: Lester H. Fink

## Exploring the Potentials of an All DC (ADC) Bulk Power System

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### Abstract

A structure as a mosaic of eight types of building blocks is proposed for the power system with block wise distributed control under the command of the Control Centers through extensive and increasingly fast communication for tracking the state and distributing the control set points to the blocks. A novel concept for managing a complex power grid is proposed; the novelty comes from combining fast power electronic-based switching with careful systems control. This combination results in an all DC bulk transmission and fully distributed control. It is proposed to compute in the Control Center, virtually instantly, the desired steady state condition of each building block and then subtract it from the existing state in each building block individually. This difference defines the excess or transient energy within each building block. One would then in each block (especially of Type [1], consisting of one bulk transmission line) utilize its series and shunt controls to eliminate this difference in voltage and current at the controlled end of each line. If this is achieved, then the excess energy which would cause transients is drained into or out of the capacitors available for this purpose. If this in turn is accomplished at all building blocks this would mean that the desired system state is realized virtually instantaneously at all times without transients across the network. This idealized situation may be acceptably approximated provided the control process is virtually instantaneous compared to the rate of variation of the desired state.

Given the present state of art of power electronics, computing and communication equipment and facilities, the question arises of how the total power system could be constructed for the best reliability, security, efficiency and other features. Notice that the question asked here is not how to utilize newly developing technology and its tools to improve existing practice, but the converse: how to utilize existing and developing technology to solve the existing problems in the most favorable way. This then raises the question of how a transition can be found. Of course, to be practical, it would be expected that current facilities such as transmission lines, generators, transformers, capacitor

banks etc. would be used, sometimes in novel roles. The innovation would involve a new structuring of the system e.g. an all DC bulk power system and a novel approach to controlling the restructured system. Innovations in several areas of the operation and control of the large power system are involved.

A limited illustration, based on existing technology is given in Section 5.

### Motivation

With the dawn of electricity trading, many fundamental technical questions arise, concerning system integrity and security under various market and equipment status changes. The overall trend is toward more distributed control/decision making closer to the generators; these are becoming smaller in size, and larger in number (distributed generation), and more distributed control/decision making closer to the (arrays, coalitions of) customers; the notion of price-responsive demand adjustment, for example [8].

The technical implementation of these trends creates a huge challenge. As the demand actively responds to the price (rather than its natural tendency), it becomes necessary to implement control at the demand level for this purpose.

This, then, leads to the major question concerning the system-wide integrity, security, stability, and alike.

We suggest that a new technical paradigm is possible in which the system-wide problems are greatly circumvented by moving to an All DC (ADC) bulk transmission and leaving the subtransmission on AC segments fed from the generating facilities at individual bulk transmission buses ahead of the AC/DC converter.

The target (set) points in steady state for All DC systems could be obtained in direct coordination with the trading needs, including response to the electricity price signals.

The distributed controllers with some sort of LC (reactive) power and energy or storage control capabilities will be the muscle behind avoiding transient and dynamic instabilities. This is a qualitatively new paradigm which requires very fast computing-communications at the All DC level, and adaptive distributed control of the non-DC components.

It is conjectured here that the degree of All DC network penetration from the bulk transmission into subtransmission and lower voltage levels will definitely depend on how fast DC penetrates the system and, moreover, on how real the price-responsive loads are.

## 1 Introduction

Predicting future developments is always a risky business with slight chances of materializing. So let us turn our imagination loose and come up with something which is intriguing and exciting even if somewhat far fetched.

As the first author thinks back to the power system as it was in the 1950's just after he arrived to the US and thinks about how he might have predicted for its present state and what has actually developed in 15 years or later, he realizes the difficulty of long range prediction. Actually he has arrived at a critical point in time. The computer arising in its slow primitive form made possible the introducing of AGC (probably the first industrial application of the computer) which made possible the fast expansion of interconnections of power companies across the country and led to the present refined interconnected system which is capable of handling its natural contingencies although in a rather awkward manner, if one thinks of it. The other major and important factor, arising at that time, power electronics, developed immensely although it currently still plays a somewhat secondary role.

Right now there are developments, such as quantum mechanical control, which are leading to orders of magnitude of further speed increase in computers. The pair of computer based advanced AC power system operations combined with the advanced state of power electronics is likely to lead the way to a very drastic rethinking of the power system of today. The logical approach may turn out to be to use the very fast computer and communication in combination with the advanced power electronics to convert the entire highest levels of the high voltage bulk transmission system into a high voltage all DC network, controlled by advanced power electronics.

Such a network would obviate most of the dynamic headaches of the current transmission system (such as stability limits, system oscillations, bifurcations) and many or most other problems. (Of course other types

of problems of a different nature may arise). The new speed level of computers (order of magnitude higher than at present) would make actions of state estimation or prediction virtually instantaneous.

Of course one could not think of just rebuilding the entire transmission network for DC use, but ways would exist for utilizing the AC equipment for DC. For instance existing three phase transmission lines could be used for DC. On double three phase lines this could be done by simply assigning the three lines one side of the high voltage transmission lines to become the plus and the other side the minus pole of the DC system. The three parallel DC circuits arising by this change could be used as one line with three parallel conductors for each, the + and - sides of DC, if they could be used as three separate DC lines each with their own separate switching measures at the ends - this would give flexibility in operation. The rated voltage of the lines would rise from the rms value to the peak value of the AC rating, a large growth in load carrying capacity. A single circuit three phase line could be converted so that the outside lines could form the DC circuit at twice the peak phase voltage of the original AC (and a half of the full DC voltage), and the center line be at the middle i.e. zero voltage.

Of course much new power electronic equipment would still be needed to connect the lines buses and generators into a network. This is a general point. Possibly only one highest voltage DC bulk transmission network would be built, or several separate ones with specially developed separation - interactive equipment.

The power system of today grew up from an initial interconnection of a few AC generators with transformers and circuit breakers. This basic structure got firmly established in the minds in the field and while radically new devices (computers, communication, HVDC and Flexible AC Transmission Systems (FACTS) plus many other power electronic devices) emerged, they were simply utilized as best they could for trying to have the original simple structure, grow to a behemoth, with increasingly complex and challenging difficulties operate with the maximum possible security.

*It would be at least interesting to ask the question of what would emerge if we were to develop the power system starting with the now available toolkit, using DC instead of AC at least at the top interaction level. This might be a starting point of such an analysis. The basic conversion of coal, oil or even nuclear power into electricity is another possible feature of such an analysis.*

Such an analysis could look far fetched and may be even foolish. Yet it may lead to practically very advantageous results, liberated from established thinking emerging from the past.

In a more direct approach one may simply note that many of the most severe dynamic problems on the large interconnected power system derive from the fact that the power now flows in form of AC. Today or in the near future it may be feasible to utilize all DC transmission systems at least in the top or bulk level of transmission networks. Below this top level, in the subtransmission networks the AC nature causes relatively few problems and has advantages which may lead to the retention of AC at least for some time, as explained below.

So it may be at least interesting to analyze, at least in a preliminary fashion, the feasibility, operability of the current difficulties with AC which would disappear and new difficulties which may emerge as well as the shape of new equipment needed for a DC equivalent. [2] The skeleton of one such analysis is presented in the following text.

## 2 The basic advantages and disadvantages of AC versus DC bulk transmission

### 2.1 The All AC System

*The three items which make AC bulk system desirable are*

1. The ease of changing voltage levels by the *transformer* and
2. The relatively easy way of interrupting current (power) flow across any cutset by *circuit breaker* and
3. The ease of converting large values of power back and forth between mechanical and electromagnetic forms in *generators* and *motors*.

In turn, the use of AC in a very large system as we have today in the US and other places creates a mountain of difficulties and problems: A very complex dynamic behavior exists across the entire bulk power transmission system from coast to coast; problems of stability, oscillations across the system, synchronization, active-reactive power, phasors, complex computations, congestion, and many others.

### 2.2 The All DC System

*In an All DC (ADC) transmission system especially one exploiting the ever faster computer and communication facilities (another order of magnitude speed up expected) almost all of these problems of AC and even the concepts of real power-reactive power, phasor, etc. would disappear and the system computation-operation would become smooth.*

The major difficulty-disadvantage is the absence so far of a DC equivalent of the *transformer* and the *circuit breaker*. Brute force solutions incorporating an inverter; transformer/circuit breaker-converter chain is feasible, using existing equipment and it would be possible to be operated using present day technology. Such equipment is under development in the FACTS world. Its economic justification and speed of operation would be doubtful but potentially possible considering the really major advantages for the ADC approach. Moreover, with the development of FACTS equipment the brute force approach will probably yield to a versatile all electronic and superfast version.

Of course, there would be new needs such as draining out the surplus energy storage in line inductances and capacitances (in place of reactive power) to eliminate system wide transients.

Given such developments All DC bulk transmission system should become a reality leading to great improvement of the stability, security, freedom from congestion and economy of bulk transmission.

A skeleton of such an intrinsic ADC system will be outlined below. It should be emphasized that this is just one example, although a logical and reasonable one and alternatives would exist. Furthermore, further developments of the technology should be anticipated.

## 3 Building block structure of the large power system based on an all DC (ADC) bulk transmission system

In general the large regulated or deregulated electric power system divides structurally into four levels as shown in Fig. 2.1 [3].

Here we are exploring how this type of system would be restructured if its transmission level was composed (Fig. 3.1, 3.4) of all DC, *lines* [1]<sup>1</sup> and *buses* [2] in an ADC fashion. For this example it will be assumed that the subtransmission level will remain as a set of conventional AC subtransmission segment [4] (which may have imbedded some isolated DC lines and also one *generating facility* [4] per DC transmission system bus [2] is assumed. One *subtransmission network segment* [3] would be connected to each transmission system bus [2]. The generating facility [3] and its generators of course are AC and jointly with the subtransmission segment [4] they form the "all"

<sup>1</sup>Framed number identify Types of building blocks as will be explained.

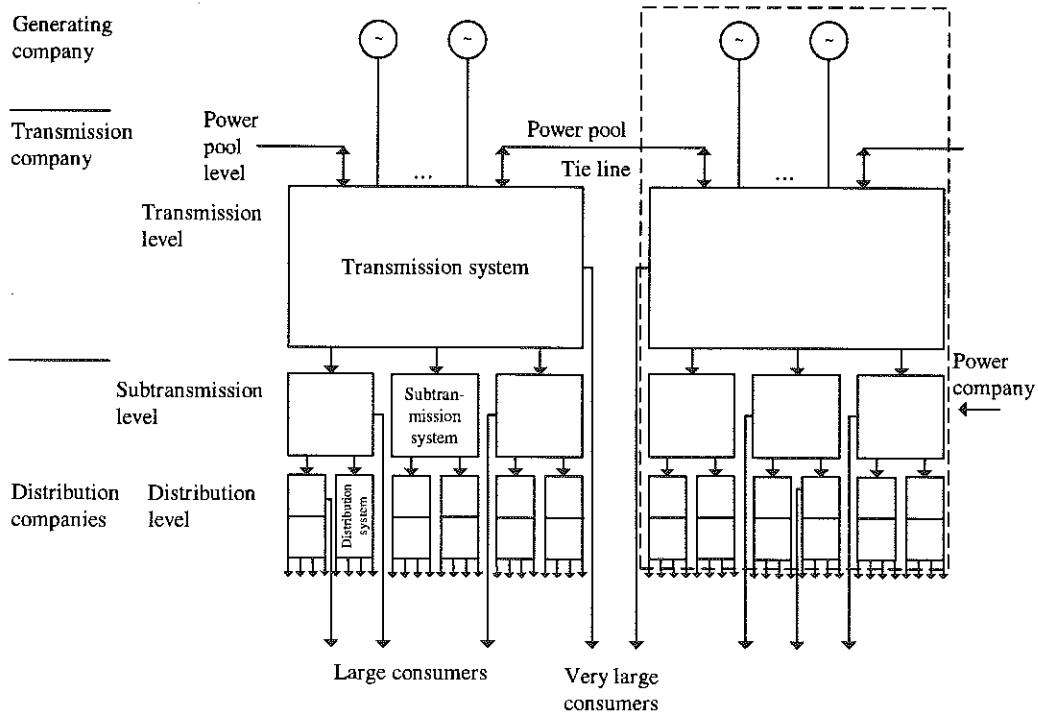


Figure 2.1: Basic traditional structure of a power system and the structural change now in progress. [3]

AC side of the system. Connection of the individual subtransmission and generation segments exists only over the ADC bulk transmission system through one specific bulk transmission system bus. While the segments are AC they are not connected with each other on the AC level and accordingly are not synchronized. They form simple and small AC networks attached to the generator [3] through a small local AC bus [5] also with one generating facility. This combination is then also connected to the ADC bus [2] through a converter-inverter type of electronics [6].

As it will be pointed out a set of charged or discharged capacitors will need to be dispatched for each ADC bus [2] this operation is organized in a block [7] finally. Activities to use frequency and IPP units as energy sources will be organized through [8].

Customers are then fed or a small generator, often independent power produces (IPP) attached from any level of the system (DC on the transmission level and AC on the AC bus [5] and from the subtransmission segment [4]) as indicated in Fig. 3.1, 3.3 and 3.4.

The system described here is sketched out in network fashion in Figures 3.1 to 3.4.

As briefly sketched here in connection with Fig. 2.1 and 3.1 it manifests itself that the complete power system

(conventional or ADC type) is composed of building blocks of a limited number of types connected and interacting with each other in an organized manner.

A type of building block as defined here consists of a set of equipment all connected to each other in a particular manner (in some building block types some of the equipment parts may be absent in some individual building blocks).

A particular type of building block will be present in large numbers within (Fig. 3.1) of the power system. Individual building blocks interact in a specific way with other individual building blocks of other different types.

These characteristics are clearly demonstrated in Fig. 3.1—3.4 for the building blocks in the three top levels (Fig. 2.1) of the power system which are of interest in this paper. Let us now list these building blocks.

*3.1 Brief description of the building blocks structure in the three top levels (generation, transmission, and subtransmission in Fig. 2.1)*

*3.1.1 Structure of Building Block-Type [1]. The ADC transmission line [1] and its control means, (Fig. 3.2). It is clear from the very simple connection diagram in Fig. 3.2 for building block Type [1] and the few very sim-*



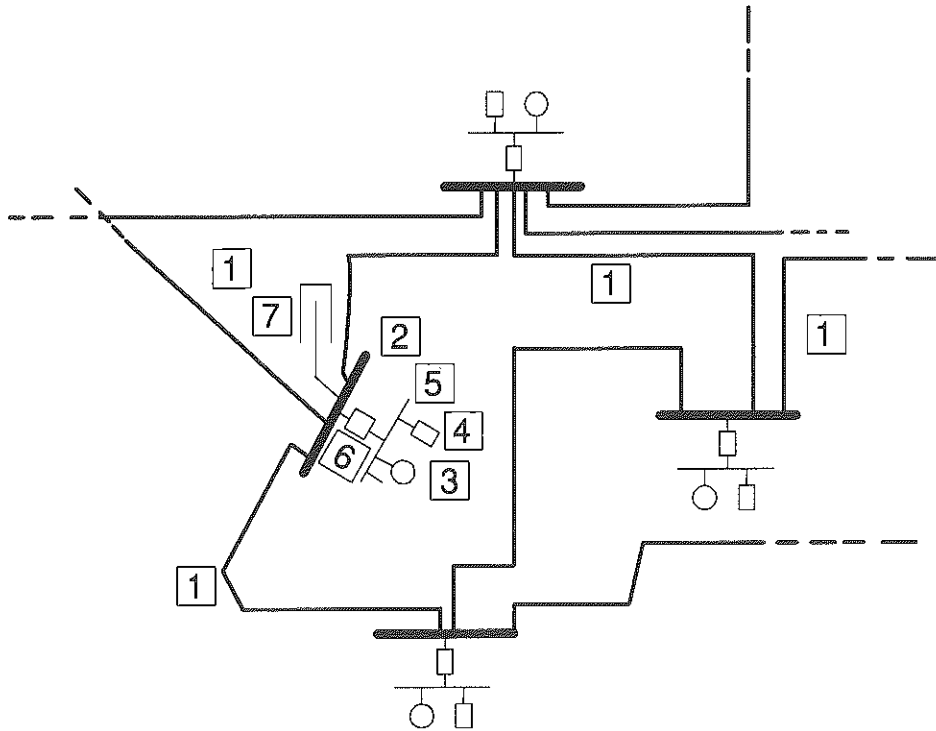


Figure 3.1: A minimal fragment of an all DC (ADC) bulk power transmission network. Note: At individual buses any or all of [3], [4], [5] or [6] may be missing.

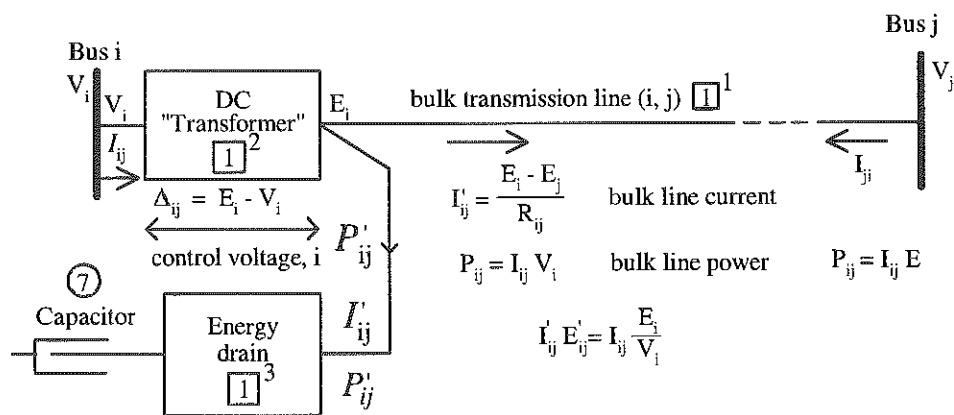


Figure 3.2: Building Block Type [1]; the line connecting bulk transmission buses  $i$  and  $j$  ([1]<sub>1</sub>) with two controls: "DC transformer" or series control ([1]<sub>2</sub>) and  $\Delta$ , or shunt control or Energy drain ([1]<sub>3</sub>). Note that the bulk transmission buses and breakers are Type [2] and not part of Type [1] their presence here just shows the connection of [1] and [2].

ple and obvious relationships shown in Fig. 3.2 (for steady state) that the transmission line outputs  $P_{ij}(t)$  (or  $I_{ij}(t)$ ) are directly obtainable given the (input) bus voltages,  $V_i$  and  $V_j$  and the control inputs to the transmission line  $i$  to  $j$ . This indicates that blockwise local control is feasible.

There are two such control inputs to building block Type [1] i.e. to bulk transmission layer lines.

1. A *series control branch* or sub block [1]<sup>2</sup> at one end of the line ( $I_{ij}$ , here) where a voltage jump  $\Delta_i$  is created between bulk transmission bus voltage input  $V_i$  and voltage  $E_i$  at the line  $i$  end. This controls the steady state current flow  $I_{ij}$  and power transmission  $P_{ij}$  from bus  $i$  to bus  $j$  as indicated in Fig. 3.2.
2. A *shunt control branch* or sub block [1]<sup>3</sup> which can draw an amount of current  $I_i$  or power  $P_i$  out of the line  $ij$  and store it in a capacitor bank (or other storage device) or vice versa. This later can be used to drain off excess energy from the line  $ij$  which would otherwise create transient swings over the network.

The details of this control approach will be explained in Appendix 3.

**3.1.2 Structure of Building Blocks, Type [2], the ADC bus [2] in Fig. 3.2, 3.3, 3.4.** The ADC bus is the interconnection point of the All DC and the AC sides of the system through the inverter-converter type building block, Type [6]. The bus itself is part of the all DC portion of the system as building block Type [2] Fig. 3.1.

An individual bulk transmission system bus (bus  $i$  in Fig. 3.3) is the point of intersection between some of the ADC bulk transmission system lines, Type [1], with one specific generating facility, building block Type [3] and with one segment of the subtransmission network as building block Type [4] and with some very large loads (e.g. an aluminum production plant, or conversely an "independent power producer", (IPP)), there may be some equipment like capacitors for energy storage building block Type [7] not shown in Fig. 3.1 or 3.3. The bulk ADC network is an interconnected network at the top of the overall power system. Logically a local AC bus will accommodate as building block Type [5] the various AC equipment mentioned as associated with the bulk buses Type [2].

On the AC side the generator equipment [3] and individual segments of the AC subtransmission system [4] are not connected to each other system wide. They form sets of individual and disjoint (without direct connection or synchronization) pieces of Type [5] building blocks connected only to one specific ADC bus,  $i$  as shown in Figs. 3.1–3.3.

**3.1.3 Structure of building block, Type [3] the generating facility attached to an individual ADC transmission bus  $i$ , (Fig. 3.1, 3.3).** No modification of conventional generating facilities is assumed in this exploration, conventional generation modeling would be applied, attached to appropriate turbine-boiler set Fig. 3.4.

It is assumed however that one specific generating facility is attached through the converter-inverter facility Type [6] to only one specific ADC bulk transmission bus,  $i$ . (Fig. 3.1, 3.3, 3.4). These individual building blocks [3] of generating facility (power plants) are not otherwise connected and not synchronized with each other, only one generating facility and one subtransmission segment is connected to any one ADC bulk transmission bus.

Independent power producing facilities of relatively small size and small volume would be acceptable on the Type [5] AC bus or within the subtransmission segment. Large IPP units will be connected to the bulk transmission bus Type [2] and are part of the ADC system bulk transmission.

**3.1.4 Structure of Building Block, Type [4].** The segment of the subtransmission system connected to ADC transmission bus  $i$  (Fig. 3.1, 3.3). The overall structure of this building block is already hinted at in connection with Fig. 3.1 and 3.3. This part of the system is quite conventional, a basic AC power system of relatively small size moderate voltage and control, with possibly some isolated HVDC lines imbedded. Small IPP's might be spread over the subtransmission network and below (Fig. 2.1).

It is important to emphasize again that the various subtransmission segments are not synchronized and are running disconnected from each other except through the ADC network. Facilities exist or are being developed however for fast transfer of pieces of subtransmission network unenergized in case of disturbances as will be described in Appendix 1. The all DC approach could be extended in the future to the segments but it is also felt that some flexibility features (Section 2.1) of AC are more desirable at the segment size and simple course structure than they would be on the bulk transmission network (ADC).

**3.1.5 Structure of the building block Type [5].** The AC bus segment attached to each individual bulk ADC transmission bus  $i$  (Fig. 3.1). Each ADC bulk bus  $i$  has a collection of AC equipment attached to it through the converter inverter [5], but not connected to any other similar collection at any other bulk bus. Specifically a single generating facility (power plant) not synchronized to any other, an isolated subtransmission segment (note: a subtransmission network is defined as not connected to any other such network and to be fed from one generating facility—see Fig. 2.1 and [3]) some larger AC loads or

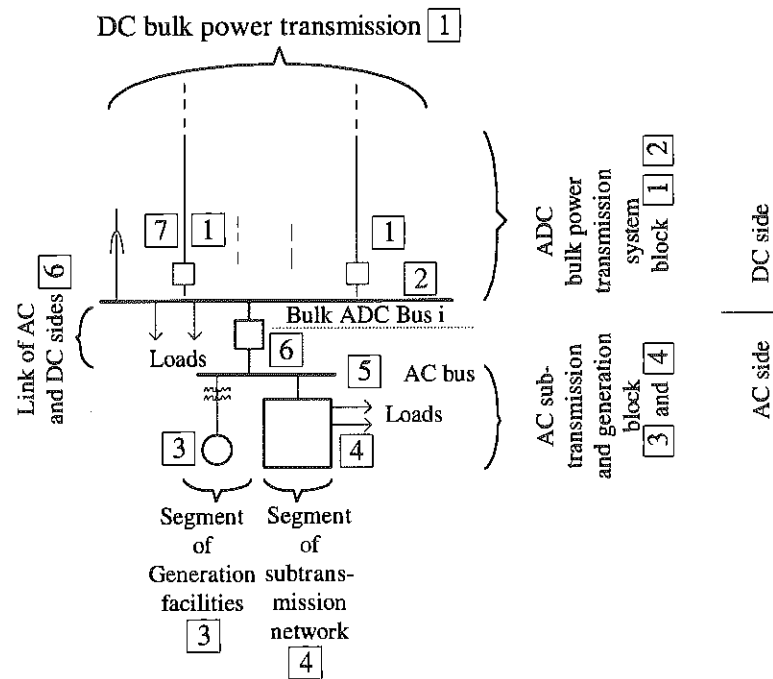


Figure 3.3: Building blocks Type [2], [3], [4] and [5]. Combination of ADC bus Type [2] with affiliated generation segment, Type [3] and load segment, Type [4].

some IPP facilities and some other equipment (on the other hand some or all of the here mentioned facilities may be absent on any specific Type [2] bulk transmission network bus  $i$ ).

**3.1.6 Structure of building block Type [6].** The conversion-inversion facility between building blocks Type [2] and [5] Fig. 3.1. A normal conversion-inversion facility, for example HVDC thyristor AC/DC station. Some modifications will appear later.

**3.1.7 Structure of the building Block Type [7].** As already indicated in 3.1.1 and 3.1.2 the proposed operation involves certain controlled draining of energy into or out of capacitors. This would involve a moderate number of capacitors for each ADC bus terminal which will need to be switched to various line terminals in a variety of polarity and in charged or uncharged condition. This implies a somewhat complex but manageable set of power electronic switches (thyristors) that will need to be designed in an optimal fashion to track and anticipate the needs of operation of the [1] and [2] Type building blocks. Obviously this combination of capacitors, switches and their operating rules will be a challenging but certainly solvable procedure. (3.7 in Appendix 3) Equally obviously, it will represent an active building block Type [7].

**3.1.8 Management of small IPP's (Independent Power**

*Producer*). IPP's are connected directly to the bulk ADC buses, [1] and the local AC buses [2] under the direct management of the Control Center the small IPP are connected to the subtransmission and distribution levels. They turn on and off and deliver just like negative loads and will need to be treated as such. Block Type [8] will provide whatever management would be needed.

**3.2 Defining characteristics of ADC system building blocks based on 3.1.1—3.1.8**

The building blocks of the power system based on an All DC bulk transmission system will now be sketched out. Observe the following basic structural features:

1. Internally the building blocks of the same Type [x] are identical in types of equipment, structure and performance. (In some specific building blocks some items may not be present, e.g. no generator connection on some Type [2] buses, but this will be usually represented by zero input).
2. The external connections and interactions of certain groups of building block types (see Fig. 3.1—3.4) are identical structurally.
3. No direct external connections exist between two individual blocks of the same type. For instance, two ADC bulk buses, Type [2], are always connected through a specific, Type [1] (transmission line) building block.

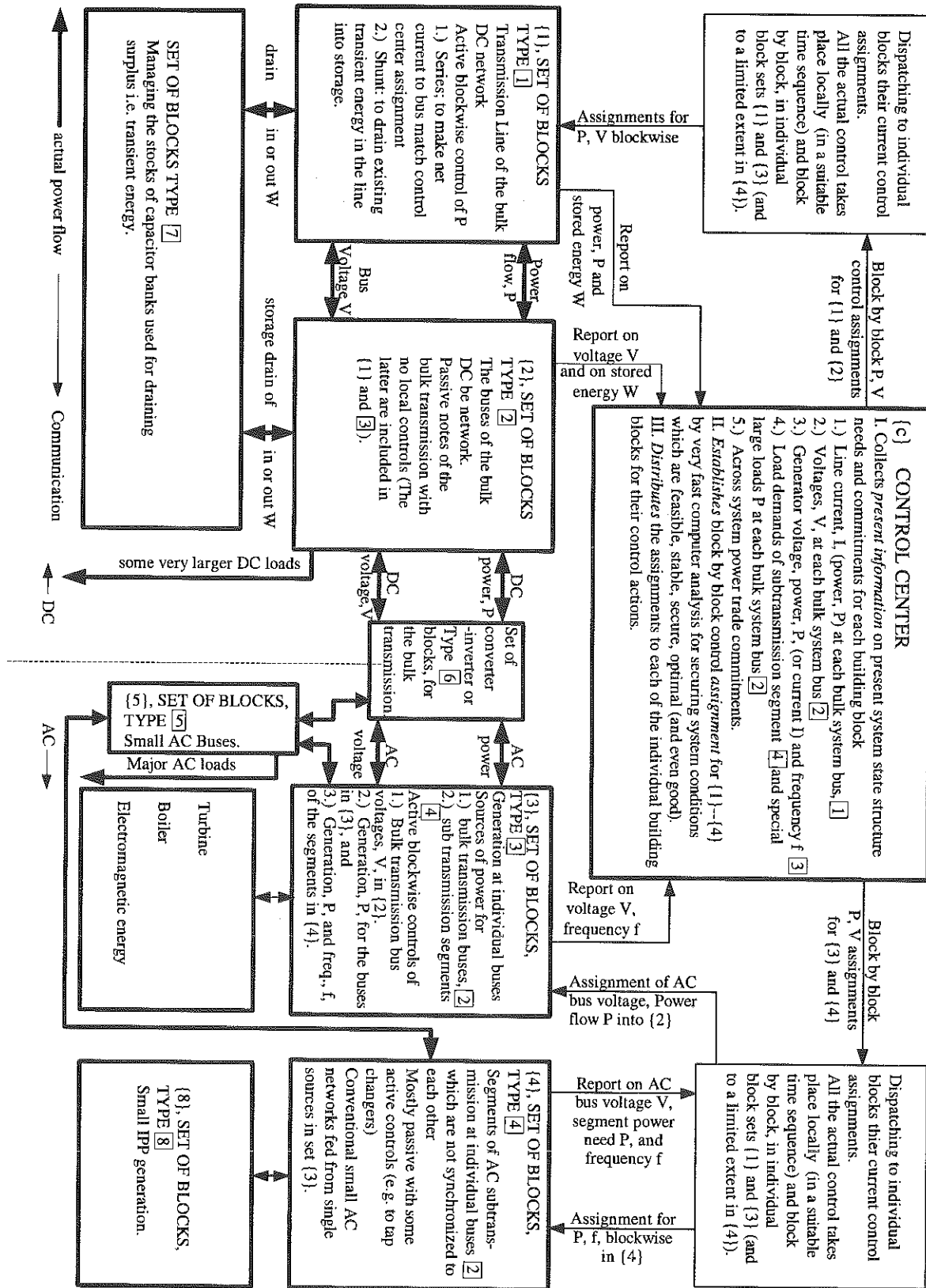


Figure 3.4: Operating structure of the system with ADC bulk transmission level.

4. Each of a given type  $\boxed{x}$  have very large numbers of members which then combine into very large *sets* to be denoted by  $\{x\}$  with no direct interconnection between members of the same set.
5. Control setpoints for all controlled variables of the system are assigned by the Control Center.
6. Actual controls are carried out decentralized internally to the specific building block  $\boxed{x}$  for each controlled variable.

In Fig. 3.1–3.4 using the building blocks  $\boxed{1}$ – $\boxed{8}$  the way of interaction and interconnection of these basic blocks was demonstrated. These interactions and interconnections are unique as they are listed just above. The actual system is very large involving very large numbers of all eight types of these building blocks each of which are large sets.

*3.3 A comprehensive connection diagram, a sort of mosaic, of these sets  $\{x\}$  shown in Fig. 3.4.*

In this figure the heavy line boxes  $\{1\}$ – $\{8\}$  represent the individual sets of Type  $\boxed{1}$ – $\boxed{8}$  building blocks, and the connections represent a specific set of connections between individual building blocks within the two boxes connected. As established, there are no individual connections between building blocks within any particular set  $\{x\}$ . Boxes of heavy boundaries and connection lines between boxes in Fig. 3.4 represent energy storage or exchange, light lines identify communications and control operations connected with the Control Center.

These are the fundamental properties of the proposed ADC system:

This diagram is comprehensive in the sense that the boxes in Fig. 3.4 contain the complete sets of building blocks of a given type, e.g. set  $\{1\}$  means a set of all building blocks of Type  $\boxed{1}$  i.e. all the bulk transmission lines and their control equipment (series and shunt for  $\boxed{1}$ ).

1. Remember that all building blocks of a given type have identical internal structure. So for instance all bulk transmission lines in  $\{1\}$  have the same control equipment for this discussion (although the absence of, say the shunt control could be handled by setting its output  $\equiv 0$  without serious problems).

(So one could think of the sets in the heavy frames in Fig. 3.4 like say telephone lines arriving into a telephone exchange independent and then individually connected.)

This figure also comprises the control of the system under the command of the Control Center (CC). An extensive communication system, as sketched in light lines in Fig. 3.4 permeates the entire system monitors

and reports to CC. A very extensive analysis and decision sources then take place in the CC as sketched in the heavy box for the CC in Fig. 3.4. Basically all control is local for and in every building block following the set points received from the CC.

Beyond that, the CC would also make the operating decisions in normal or abnormal condition following some operating policy which may include some type of optimization.

This Fig. 3.4 gives a comprehensive conceptual picture of the ADC System. It will be utilized in Sections 4–5.

2. All connections between pairs of building blocks are two blocks of different type.
3. All connections between powers of building blocks of the same two types are identical in structure.
4. No connections exist between two building blocks of the same type, all individual members of a set  $\{x\}$ , the contents of any heavy line box in Fig. 3.4 are disjoint within that box.
5. All connections between pairs of types of building blocks are identical in character and topography e.g. no two bulk buses are connected directly within the  $\{2\}$  box in Fig. 3.4 but any two buses  $\boxed{2}$  are connected through a transmission line  $\boxed{1}$ .

Thus Fig. 3.4 summarizes in heavy lines the operating structure of the building block Type in heavy lines the structure and operation of the AGC system as introduced piece meal above including such characteristics as non-synchronized subtransmission (no AC connection between type  $\boxed{4}$ ).

An example will be presented in Section 5, and somewhat limited in scope by the nature of this writing. Please remember that this is an “exploration” based on some assumptions about certain expected developments of technology, mostly in the area of speed of computation and development of special programs for the Control Center and in power electronics which are not yet accordingly linked although realistically expected or planned.

Consequently the example had to be based on some material available in the literature. Even so it was possible to demonstrate some of the new ideas offered in this paper.

## 4 Operation and control of the large power system using ADC and ultrafast switching

After establishing in Section 3 the building block structure of the ADC system with the equipment in the blocks and

their way of operation within the blocks, next we can now look into how this system will operate and how it can be controlled.

System conditions fall into three categories:

- i. Steady state operating conditions, and conventional gradual shifting of the loads;
- ii. Operating conditions following sudden changes in the system structure; and
- iii. Operations during dynamically disturbed conditions.

Before discussing these operating conditions individually, let us briefly summarize the general operating procedures under the command of the Control Center.

#### 4.1 General aspects of operation and control of the ADC system

With reference to Fig. 3.4 we can observe the basic organization of operating and controlling this complex but well organized system.

First of all the eight types of building blocks congeal, in an organizational and programming sense, into eight sets of very large membership as shown in Fig. 3.4.

To recapitulate:

1. Each of the Sets  $\{x\}$  is composed of essentially identical Types (one of eight sizes,  $\boxed{1}$ – $\boxed{8}$ ).
2. The Types  $\boxed{x}$  of the members within one set  $\{x\}$  are all essentially identical in equipment, structure operation to all other members of the same set.
3. There is no direct interconnection between any two members of any Set.
4. Members in one Set may be connected to one or more other Types, provided
  - (a) The pattern of connections is the same for each individual Type  $\boxed{x}$  within one Set.
  - (b) No connection goes directly to a Type  $\boxed{x}$  building block within the same Set.

The basic and general feature of this process is the control of each building block individually and locally, in response to the control center which establishes and communicates set points to each building block individually.

The Control Center has the global view and the ability to establish a system wide plan for control settings, provided a very fast communication and control is available for the Control Center to see overall system state and to analyze and decide the most desirable actions for the building

blocks in the active sets  $\{1\}$ ,  $\{3\}$  and  $\{7\}$  where control actions are available. This then will also imply desirable setpoints in the inactive sets  $\{2\}$  and  $\{4\}$  which will be automatically reached if the process works correctly.

To provide the overall view to the CC it is necessary to establish a well organized and complete communication system for each building block from and to the Center. This reporting needs to be done once in every  $\Delta t$  seconds.  $\Delta t$  must be long enough to give the CC time to carry out its system wide and building block wise analysis and reach a system wide control action plan and then to give the system time to respond substantially, within a small fraction of  $\Delta t$  to the plan after the individual building blocks received and carried out their assignment for control actions properly. The aim and planned steps are:

1. An all DC (ADC) transmission system free from active-reactive power complexities.
2. Separate individual building block wise control in a simple manner which concentrates the solution of systemwide dynamic interaction monitored and directed in the Control Center computer.
3. Such control then results in a smooth shifting of the system from DC steady state to DC steady state over consecutive  $\Delta t$  intervals for the typically slow moving loads in normal operating conditions.
4. This means that no significant system wide transients exist because the energy difference between the steady state at  $t$  and that at  $t + \Delta t$  (the consecutive time instances when the CC control commands are given), is drained off locally within the individual active building blocks of the type,  $\{1\}$ ,  $\{3\}$  and  $\{7\}$ . The drained energy is stored in capacitors in  $\{7\}$  and fed back into the system through thyristor manipulations, or through the generators in order to eradicate system wide dynamic swings.
5. The ready and smooth block by block shifting of the state building block by building block makes it easy to steer and smoothly distribute power flow needs resulting from across the network near or far and to minimize and easily compute losses.
6. There is no active and reactive power, no phasors, no complex computations, no stability problems, no energy swings across the system, no across system or interarea swings.
7. A word of caution, though. The preceding claims are based on an assumption that all loads, generation all network constants and network states are reported to the CC; all assignments leave from the CC; all equipment operating models etc. and all computations and operations are precisely known and available sufficiently fast to be carried out within a sufficiently

short time. All these would be good approximations but the “virtually” instantaneous speed of responses is still limited although their speed is increasing steadily, an order of magnitude speedup in computers is currently expected relatively soon. Total precision is impossible. Consequently a measure of perturbation signals or noise will be present. Hopefully these will be of a non problematic nature. However careful study must be done.

**4.1.1 The Control Center.** The basic operation activity of the Control Center is briefly sketched in the large heavy box {c} in Fig. 3.3.

Some additional details follow here.

The Control Center (CC) receives detailed reports every  $\Delta t$  intervals of the system state: voltages, currents (or power) at  $n$  specific locations covering all building blocks.

Specifically, inputs come from:

1. Large loads (like an aluminum plant fed directly from the bulk transmission system buses [2]).
2. Independent Power Producers (IPP's) connected to the bulk transmission buses [2] with loading schedule.
3. Larger loads connected to the small AC buses [5].
4. Largish IPP's connected to the small AC buses [5].
5. The total load taken by each individual AC sub-transmission segment [4] including small unscheduled IPP's connected to the subtransmission and distribution network. The latter here act mostly as negative load items.

Summary of Control Setpoints.

1. Voltage,  $V_i$ , of bulk power system bus [2], Source: Control Center.
2. Power,  $P_i$ , (or current,  $I_i$ ) flow through the bulk transmission lines into each bus  $i$ , Source: Control Center.
3. Power (or current) flow into each ADC bus out of the converter-inverter [6], Source: Control Center.
4. Transient energy content of bulk transmission lines (always zero in the steady state).
5. Voltage,  $V_i$  on the segment feed point i.e. the local AC bus [5], Source: Control Center.
6. Frequency,  $f_i$  on each segment, Source: Control Center.
7. Availability of drainage space [7].

Summary of Corresponding Control Equipment.

1. Inverter-Converter power control.
2. Inverter-Converter voltage control.
3. Bulk transmission line series branch control of power flow.
4. Bulk transmission line. Shunt branch (control of transient energy drainage inactive in the steady state).
5. Generator Excitation Control.
6. Generator Control Valve.

Let us now discuss the three basic operating conditions.

#### 4.2 Operation and control of the ADC system in the steady state

The two layers for the power system respectively, on the AC and ADC sides, will be discussed here in sequence.

**4.2.1 Steady state in the ADC bulk power transmission layer.** The basis for the steady state control settings is the establishment of the assigned load flow carried out by the Control Center for the whole system based on some optimal policy (like earlier on AGC). The major deviation here is the all DC character of the bulk power transmission system and the requirement to get the result precisely but very fast (“virtually instantaneously”), to allow effective measures to prevent transients. It is generally much simpler to do this for all DC than for AC (no more active or reactive power, no complex computation, all goes in real, etc.).

The available controls were specified in Section 3 for all eight types of building blocks on both layers i.e. sides of the system (transmission, ADC-subtransmission, AC). Their use in the steady state will be described now. (see Fig. 3.4).

- 1.) *Steady state voltage on the bulk power transmission system buses.* These are individually maintained by the voltage output of the electronic inverter-converter [6]. (Fig. 3.4) at the point ordered by the Control Center.
- 2.) *Power or current injection into the bulk system buses in the steady state.* These are maintained through the electronic converter [6] and the series control equipment ( $\Delta$ ) on the all DC transmission lines [1], connected to the bus. The control setpoints, again set by the Control Center, are the DC current (power) output at the DC terminals at the bulk bus (Fig. 3.1 and 3.3).

Note that these two control inputs at all buses will uniquely determine the load flow and voltage profile at all buses on the transmission system matching those computed in the Control Center.

3.) *The shunt control means on the bulk power transmission lines.* Accordingly these shunt controls should be set on their nominal position, in the steady state (Fig. 3.1 and 3.3).

**4.2.2 Operation with typical load variations.** The assumed steady state control operates with the control center assigning control setpoints every  $\Delta t$  seconds. It was also (tacitly) assumed that the system loading and generating condition have not changed within  $\Delta t$ .

On the actual system the loads and generation vary slowly (with a fast small perturbation on top) compared to the  $\Delta t$  side of control assignment cycle and the system will respond during a small fragment of  $\Delta t$ . Under these circumstances the control process proposed will perform without more than a slight perturbation.

**4.2.3 Steady state in the subtransmission layer.** While the building blocks in the transmission layer are directly connected in a mosaic, in the subtransmission [4] and generation [3] layers, the layer of the segments is broken up into disjoint segments, one segment per bulk transmission system bus (Fig. 3.1–3.4). These segments are isolated from each other and not synchronized. Within the realm of one ADC bus however generation, subtransmission, some loads and IPP will be connected to any AC bus [5].

Thus, the layers of the generation and the subtransmission segments (or the local AC bus) are a large number of small and simple AC networks with, possibly, a few occasional and individual AC-DC lines imbedded in some of them, Fig. 3.4.

Each of the ADC buses and attached segments has just one generating facility attached. They are isolated from each other on the AC level and thus are not synchronized to any neighbor. So they are quite small individual systems.

Accordingly they are controlled individually and conventionally at their connection point to the segmented generation at the local AC bus [5] just ahead of the inverter [6] to DC. (Fig. 3.4). Their voltage and frequency are set by the generator controls and their power flow needs to supply the customers on the subtransmission segment [4] covered by the segment, [3], by adding them to the power supplied by the generator into or out of the bulk transmission system.

**4.3 Operation and control of the ADC bulk transmission level after sudden changes of the system structure.**

After a sudden structural change a different system structure and the desirable load distribution on it will emerge suddenly and it will be virtually instantly identified in the Control Center where a desired voltage and power flow for

the new structure will be identified by computation and communicated to the building block controls in a very short time relative to system transients.

Once this is done the task to establish the new steady state becomes identical to the task of steady state control, which was described in Section 4.2. There is a difference, however. We are now talking about steady state distribution in which sudden changes just emerged and were analytically identified. Consequently the electromagnetic energy of the old and different equilibrium still is physically in the system. This difference must be eliminated to move the system into its new steady state equilibrium. Left alone this will be reached by system wide transient swings damped by the line resistances. Here we propose a novel approach to control of transients – by draining the transient energy out of the individual system transmission line as follows.

**4.3.1 The draining out the bulk transient energy to prevent transient system swings on the bulk power system after sudden changes of the system structure.** For the sudden shift of steady state of the ADC system considered in this section the process can be summarized as follows: (also see Appendix 2 for a thought experiment)

1. The system is divided into eight types of building blocks (bulk transmission lines [1], buses [2], subtransmission segments, [4] generation [3], local AC buses [5], converter-inverter [6], set of capacitors for energy draining, [7], management of the small IPP in [8]).
2. Changes of the steady state DC voltages and power flow are computed very fast in the Control Center and then communicated as setpoints and implemented building block by building blocks by using their local controls i.e. the series voltage control,  $\Delta$ , in [1]<sup>2</sup>, and the shunt flow control in [7] plus the power input from the converters [6].

This physically establishes the new steady state flow and voltage on the bulk, DC, transmission system and makes it possible to enforce it provided:

3. The excess or deficiency of transient energy can be drained, to or from, capacitor banks (or other storage, like rotors) through the shunt control branches [1]<sub>3</sub> of the transmission line building blocks [1]. (Appendix 2)
4. Since the voltage and current at the  $i$  end in the  $ij$  line change for the new steady state following the sudden change can be computable in the Control Center for each of the bulk transmission lines and communicated to the controls on the line very fast, it is then possible to use the series and shunt controls of the line  $ij$  (see block [1] in Appendix 2 and 3) to adjust the  $V_i$



voltage and the  $I_{ij}$  current on the  $ij$  line to the new static value very fast with  $V_i$  and  $V_j$  adjusted by the electronics in [6] even before the fast adjustment of the current  $I_{ij}$  (Appendix 3). This adjustment then will automatically drain the difference of the energy stored in line  $ij$  before and after the sudden change resulting in a virtually instantaneous shift of the system steady state to accompany the sudden shift of the system structure (e.g. drop out of a generator) without any substantial system wide transient swings. The latter could be quite violent since in ADC conditions on the bulk transmission system is a simple RLC circuit (no reactive power, reactance etc.) superimposed on the DC static flow. Very long transmission lines will inject some additional complexities.

**4.3.2 Slowly Changing System State.** The technique described in Section 4 takes the system from one steady state condition to another. The quick transition is achieved by a proposed control technique which results in a fast rearrangement of the energy stored in individual lines or masses by local actions utilizing local energy storage facilities at the buses. The restrictive assumption here is the bulk change from one steady state to another in a jump fashion. Now consider:

1. These techniques are likely to give good approximate results even if the “steady states” before and after the sudden change are not really steady but only very slow varying compared to the time required for draining out of the individual lines the excess, i.e. “transient energy” left after the switch of steady states, as proposed. This speedup of the computation-communication technology is, however, the basic assumption of this proposed ADC system.
2. Then again if there is no jump but the state is changing softly in a general system wide transient, as we are here considering, the fast draining mechanism could also track the slow variations with a periodic adjustment, say every  $\Delta t$  second, on CC orders, slow change. This then means that any system wide transient swings are drained out before they develop with a slight delay so the ADC operation can follow its steady state or slowly changing operation without any superimposed RLC swings on the system. This would create a new way of dealing with transient disturbances on the bulk ADC transmission system.
3. This approach presented in a sketchy manner here needs to be subjected to a truly penetrating analysis with both mathematical and operating means. No attempts can be made here to indulge in explaining or forecasting these studies.

**4.3.3 Operation and Control of the layer of the segments after sudden changes of the system structure.** The segments are, essentially conventional AC subtransmission

systems and their behavior during disturbances will also be fairly conventional.

As part of this structure with an ADC bulk system however and with the aim of keeping the majority of the customers as undisturbed as possible some interesting and important special aspects emerge such as transferring parts of a disrupted subtransmission system to neighbors without synchronization. (see Appendix 1).

#### 4.4 Dynamic system state

In Section 4.2 it was assumed that the disturbance was a sudden change in the system structure such as the loss of a generator, line, large load etc. In this situation it can be assumed that given a capability of very fast distributed control response as is proposed here the system state can be directly shifted to a new equilibrium before major dynamic transients develop. This made the explanation of the basics of the proposed way of operation easier.

In the general case discussed in this section the system would be in a dynamic situation even before the disturbance process takes its course which may include a sequence of faults, the dropping of lines or other equipment etc. By its tendency to keep the system at a feasible and stable equilibrium, however, the new approach will tend to shorten and smooth out these possibly prolonged transient converging chain of events.

#### 4.5 Some future work

In order to further explore the concepts presented here, it is necessary to develop a solid analytic basis for this novel approach to the dispensing of power over an All DC transmission system. Several quite novel and unusual tasks are outlined in the preceding description which are not simple transformations of conventional AC bulk power transmission. The most challenging ones are:

1. Develop an analytic theory and computational approach for the system with all DC bulk power transmission to replace the very large body of such methods now existing for the AC system based on phasors active and reactive power etc. which have limited meaning or validity for ADC.
2. The composition and system structure for ADC is defined as a mosaic of four types of building blocks. This representation needs to be properly defined for analysis and computation.
3. A special new type of interplay between the Control Center and the building blocks is proposed and it needs to be formally established.
4. It is assumed that computation and equipment (FACTS) are now moving to become fast enough

to become virtually instantaneous compared to the movement of system wide transients and load demands.

5. It is then proposed to use controls block by block to maintain the main power flow and voltage command by the Control Center. Simultaneously electromagnetic energy in excess or shortage of the amount within the mosaic flow ordered by the Control Center would be drained (or from) block by block into storage and then fed back into the mosaic flow. A novel way of dynamic control resulting in a smooth following of demands on the system without transients (modulo some small perturbations). This approach needs to be analyzed in depth. Above are only some of the tasks involved in this.

## 5 Simulation on a small scale example <sup>2</sup>

To show adequate functioning of the proposed alteration of the AC system, a nine bus example was implemented in Matlab. The nine bus system studied in this paper is based on the nine bus studied in [4, 5]. In Figure 5.1 a topology altered system (compared to the example in [4]) is shown, in particular AC lines  $e_{57}^a$ ,  $e_{89}^a$ ,  $e_{46}^a$  where changed to form DC lines  $e_{47}^d$ ,  $e_{79}^d$ ,  $e_{49}^d$  respectively. This AC cut was chosen in order to associate strongly connected loads (small  $X_{ij}$ ) with each generator. The DC lines now interconnect three similar AC subsystems. This type of DC interconnection has previously been identified in the literature and termed, MDC (Multiterminal DC) systems [6]. It is not the ADC system, but approximates it to a degree.

### 5.1 AC/DC converter stations

The AC and DC systems are joined through AC/DC converters. In this paper HVDC thyristor technology was chosen for the implementation of these converters. It is important to stress that we are not limited to this technology and converters that give more degrees of freedom like IGBT controlled converters can be implemented.

Twelve pulse, single pole thyristor converters were implemented. Note that a six pulse converter might suffice, but better harmonic performance of the 12 pulse system will help reduce the stress on the shunt and series control devices found both sides of a DC line (to be discussed in the next section). The inverter-converter at AC buses 4 and 7 were chosen to be rectifiers, and the inverter-converter at AC bus 9 is an inverter. At the converter buses we have an interface between the DC and the AC systems, which

is made explicit by the following:

$$V_i^d = 2 \times \mu_i \left( \mu_i \frac{3\sqrt{2}}{\pi} V_i \cos \alpha_i - \frac{3X_i^c}{\pi} I_i^d \right), \quad (1)$$

where  $V_i^d$  is the average value of the DC side voltage of the converter,  $I_i^d$  is the DC side current flowing,  $\mu_i = [1; 1; -1]$  for  $i = [4; 7; 9]$  respectively and nominally  $0 \leq \alpha_{4,7} \leq \frac{\pi}{2}$ ,  $\frac{\pi}{2} \leq \alpha_9 \leq \pi$ .  $X_i^c$  is the commutation reactance, and per AC Area is approximate  $X_i^c = x'_{di} + X_{ij}$  where  $x'_{di}$  is the applicable generator's d-axis transient reactance,  $i = [1; 2; 3]$  and correspondingly  $j = [4; 7; 9]$ <sup>3</sup>.

### 5.2 Bulk transmission lines' shunt and series control devices

In this section the shunt and series branch devices will be combined to form one black box. In Figure 5.2 the current and voltage relationships for such a device are shown.

The control center is responsible to compute and communicate the device output voltage set points,  $E_{ij}^{sp}$ .<sup>4</sup> Practically  $E_{ij}$  might need to be controlled in order to follow  $E_{ij}^{sp}$ . Lines are mainly inductive, making purely steady state (instantaneous) operation of the bulk transmission lines difficult. If  $P_{ij}$  is from  $i$  to  $j$ , but at the next time instance the flow needs to be reversed, then  $I_{ij}$  can not instantaneously be redirected. By controlling  $E_{ij}$  to change gradually instead of instantaneously the stress on a device can be lessened (model based control is a good candidate). However, in this section it will be assumed that the device can instantaneously follow any setpoint changes and that the DC lines are purely resistive. (see Appendix 2 explaining these matters). The combination of the series and shunt controls with drainage however makes it possible to keep the line current, constant and adjust the series current instantly (see Appendix 2).

The shunt branches on both side of  $e_{ij}^d$  can draw (or inject) a current ( $I_i$ ) out-of (or into)  $e_{ij}^d$ , hence storing (or extracting) it in (or from) a storage device.

Current technologies that might be used to realize the DC voltage drop across the device is a full bridge DC/DC power converter. The full bridge DC/DC converter allows four quadrant operation and power can flow from DC side 1 to DC side 2 and vice versa. Energy storage can be achieved by using shunt capacitors or inductors (maybe superconducting coils) that are appropriately placed. An economic evaluation of the feasibility using current technologies need to be done. (see also block 7 in Appendix 3).

<sup>3</sup>All susceptances are ignored and the lines are taken to be lossless.

<sup>4</sup>In Figure 5.3 the output voltage of the DC transformer is defined as  $E_i$ . In this section a double subscript is used for the same variable to account for the fact that multiple DC lines can emanate from the same DC bus. Thus  $E_{ij}$  is the output voltage of the DC transformer situated at DC bus  $i$  for the DC line  $e_{ij}^d$ .

<sup>2</sup>The contribution in this section was mainly made by Ernst Scholtz, a doctoral candidate at MIT.

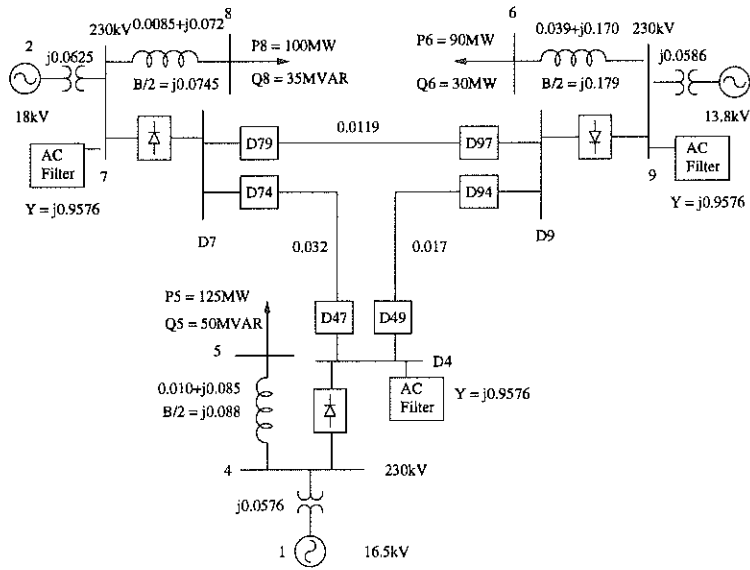


Figure 5.1: The nine bus example under investigation. All the parameters are expressed assuming  $S_{base} = 100\text{MVA}$ . For the DC lines only the per unit resistances are shown.

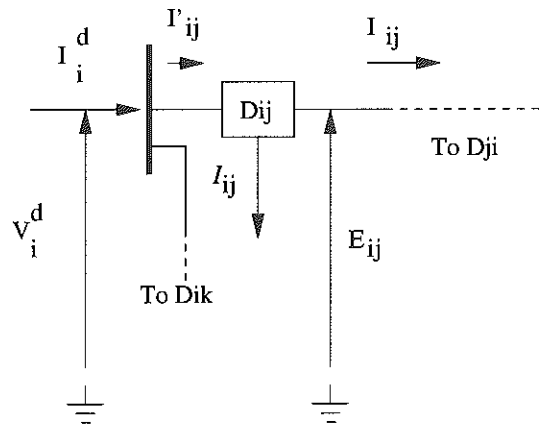


Figure 5.2: Black box formulation of Device 9 and 10.

For the mathematical approach there are two alternatives that can be investigated, focusing on the storage(or injecting) capability of these devices. The alternatives are:

- The storage device or injecting source has infinite i.e. (large enough) storage and sourcing capability.
- The storage and sourcing capability of the device are finite.

The significance of the first alternative is that due to the way the black-box device can be implemented, a perfect DC voltage  $E_{ij}$  will be exhibited on the bulk transmission lines. Thus no transient on the AC side will progress through to the DC side. Thus for such a device the only conceivable dynamics on the DC lines would be due to the inductive and capacitive nature of high voltage transmission lines. Capacitors of large enough size should not be a technical problem one needs to assess their economics.

For the second alternative, AC side transients can progress through to the DC lines. The reverse also holds and if the unrealistic assumption is dropped that the DC lines are purely resistive, then these DC side transients will influence the AC system.

The voltage at, and current flowing into, the DC side of the converter (DC bus  $i$ ) are,  $V_i^d(t) = V_i^d + v_i^d(t)$  and  $I_i^d(t) = I_i^d + i_i^d(t)$ . As a first iteration the converter output voltage will be taken as the average voltage term given in (1). The normal discrete switching waveform is not considered, but forms part of the extension of this work. This average voltage will exhibit dynamical behavior which is dictated by the dynamics of the AC subsystem. See Figure 5.3 for dynamical responses of these average DC bus voltages.

The following current and voltage relationships are applicable for these devices<sup>5</sup>:

$$I_{ij} = \frac{E_{ij} - E_{ji}}{R_{ij}},$$

$$\text{where } R_{ij} = R_{ji} \text{ (steady state equation)} \quad (2)$$

$$\Delta_{ij} = E_{ij} - V_i^d \quad (3)$$

$$I'_{ij} = I_{ij} + \mathcal{I}_{ij} \quad (4)$$

$$I_i^d = \sum_{j \in \mathcal{C}_i} I'_{ij} \quad (5)$$

$$P_{ij}^{in} = V_i^d I'_{ij} = V_i^d I_{ij} + V_i^d \mathcal{I}_{ij} \quad (6)$$

$$P_{ij}^{out} = E_{ij} I_{ij} \quad (7)$$

$$P_{ij}^{dev9\&10} = V_i^d I'_{ij} - E_{ij} I_{ij} = -\Delta_{ij} I_{ij} + V_i^d \mathcal{I}_{ij} \quad (8)$$

$$P_{ij}^{dev9} = E_{ij} \mathcal{I}_{ij} \quad (9)$$

$$P_{ij}^{dev10} = -\Delta_{ij} I'_{ij} =$$

$$-E_{ij} \mathcal{I}_{ij} + V_i^d \mathcal{I}_{ij} - E_{ij} I_{ij} + V_i^d I_{ij} \quad (10)$$

$$\mathcal{P}_{ij} = E_{ij} \mathcal{I}_{ij} \quad (11)$$

<sup>5</sup>Note that  $E_{ij}$  is not necessarily equal to  $V_i^d$ .

where  $\mathcal{C}_i$  is the cut set of node  $i$ .

### 5.3 AC subsystems

Each AC subsystem consists of a synchronous generator (round rotor), an IEEE Type 1 Voltage regulator, a Hydraulic Turbine and Governor Unit, a step up transformer (from generation to transmission voltage levels) and an AC transmission line feeding an AC load. In table 1 the dynamic parameters of the generators are given. All the applicable impedances of the network are indicated in Figure 5.1.

The DAE model has 56 (ADC system and 53 for the MDC system) states, which are broken down as follows:

- 9 states per generator (dynamic);
- DQ currents of generators (algebraic);
- 9 Terminal voltages (algebraic);
- 8 Voltage angles ( $\theta_1 = 0$  is fixed) (algebraic);
- 3 Converter currents (dynamic - for ADC system, algebraic - for MDC system);
- 3 DC bus voltages (algebraic) - Not part of the MDC system.

The state space model associated with an AC subsystem is standard and books [5, 3] can be consulted. The parameters for the regulators were taken from [5].

A DC system DAE model can be constructed where the state in question is the current through the applicable smoothing inductor,  $L_i^d$ , on the DC side of the inverter-converter.

$$L_i^d \dot{I}_i^d(t) = \mu(V_i^d(t) - V_i^{dbus}) \quad (12)$$

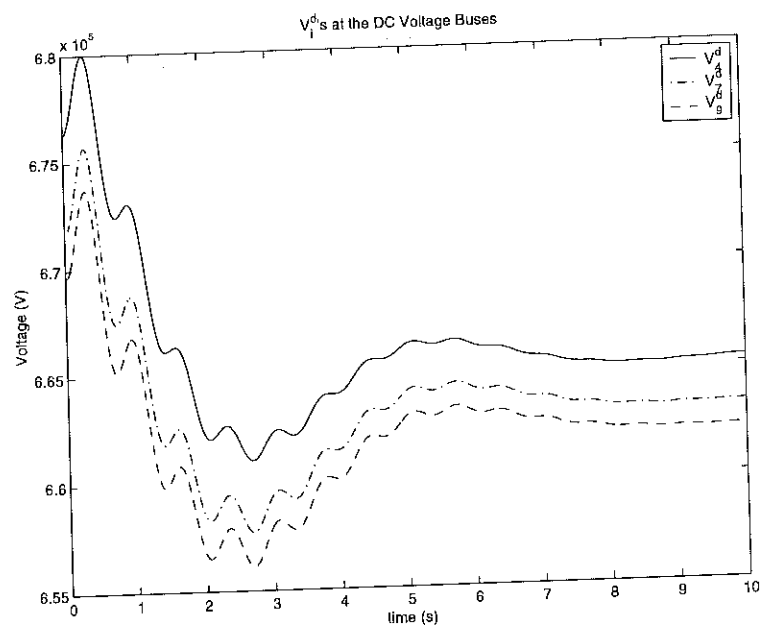
The algebraic variables  $V_i^{dbus}$  are solved using one of the loadflow equations (which became available after fixing  $\theta_1$ ) and 2 other independent equations. (see (18) and (19)).

For the MDC system, the  $I_i^d$ s are algebraic variables and the above mentioned independent equations are used in the DAE model while the state equations of the smoothing inductors and the  $V_i^{dbus}$ s drop out. The DAE model of the ADC system is still under development. Recall that a MDC is just an approximation of ADC so results should be considered with this in mind.

### 5.4 Loadflow

Different algorithms and approaches exist for the computation of the AD/DC loadflow. (see Chapter 4 of [7]). The following assumptions are made for the steady state analysis of AC/DC converters:

- The AC system's voltages at the terminal busbar are balanced and sinusoidal.



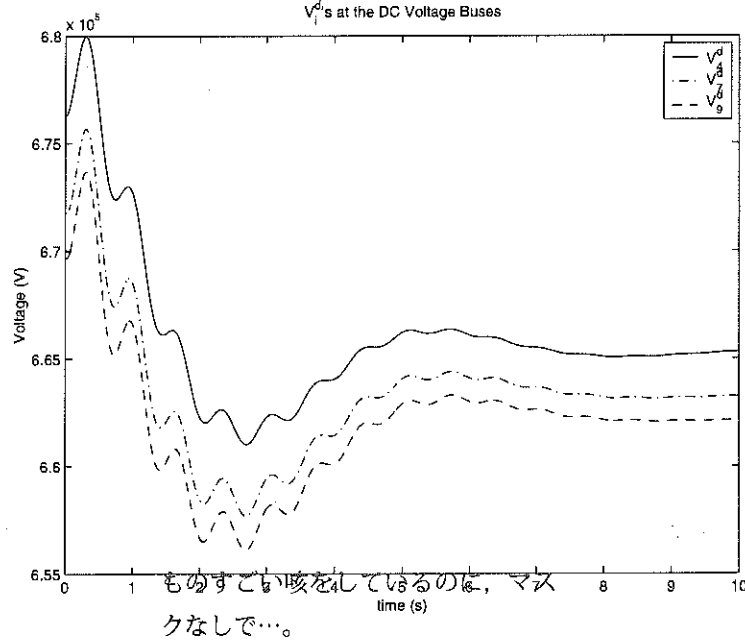


Figure 5.3: Dynamic response of the average voltages at the DC buses after the application of a perturbation. See section 5 for event description.

Table 1: Generator data for the nine bus example (all reactances are expressed in per unit with a 100MVA base) [4, 5].

| Parameter              | Gen 1  | Gen 2  | Gen 3  |
|------------------------|--------|--------|--------|
| $S_n$ (MVA)            | 247.5  | 192    | 128    |
| $x_d$ (pu)             | 0.146  | 0.8958 | 1.3125 |
| $x'_d$ (pu)            | 0.0608 | 0.1198 | 0.1813 |
| $x_q$ (pu)             | 0.0969 | 0.8645 | 1.2578 |
| $x'_q$ (pu)            | 0.0969 | 0.1969 | 0.25   |
| $H$ (s)                | 23.64  | 6.4    | 3.01   |
| $\frac{D\omega_s}{2H}$ | 1      | 1.2    | 1.5    |
| $T'_{d0}$ (s)          | 8.96   | 6      | 5.89   |
| $T'_{q0}$ (s)          | 0.31   | 0.535  | 0.6    |

- The converter operation is balanced.
- The DC side current and voltage have no ripple components.
- The converter transformer is lossless and magnetizing of it is ignored.

Traditionally HVDC converter buses have been handled as PQ buses in the AC loadflow. Active power can flow from the AC side to the DC side (rectifier mode) and vice versa (inverter mode), however in both modes of operation of a converter extracts VARS from the AC side.

It was decided to split the loadflow problem and calculations of  $E_{ij}^{sp}$  (i.e. optimal DC power routing) into two

Table 2: Loadflow classification of the buses (17 unknowns).

| Type of bus | Bus number        | Unknowns                  |
|-------------|-------------------|---------------------------|
| Slack       | $i = 1$           | -                         |
| PV          | $i = \{2, 3\}$    | $\theta_i$                |
| PQ          | $i = \{5, 6, 8\}$ | $\theta_i, V_i$           |
| AC-DC       | $i = \{4, 7, 9\}$ | $\theta_i, V_i, \alpha_i$ |

problems. Thus in the loadflow problem it is assumed that  $\Delta_{ij} = 0$ .

The loadflow equations for the AC system are (14 equations):

$$P_{Gi} + P_{Li} + V_i \sum_{j \in C_i} V_j (G_{ij} \cos(\theta_i - \theta_j) + B_{ij} \sin(\theta_i - \theta_j)) + V_i^2 G_{ii} = 0, \forall i = 2, \dots, 9 \quad (13)$$

$$Q_{Gi} + Q_{Li} + V_i \sum_{j \in C_i} V_j (G_{ij} \sin(\theta_i - \theta_j) - B_{ij} \cos(\theta_i - \theta_j)) - V_i^2 B_{ii} = 0, \forall i = 4, \dots, 9 \quad (14)$$

where  $P_{Gi} > 0$  when power is delivered and  $P_{Li} < 0$  when power is extracted from the AC system (same holds for reactive power). At the converter buses the power and reactive power are given as<sup>6</sup>:

$$P_i = -\mu_i V_i^d I_i^d, \quad (15)$$

$$\phi_i = \arccos\left(\frac{1}{2}\mu_i \cos \alpha_i - \frac{\sqrt{3}}{2\sqrt{6}} X_i^c \frac{I_i^d}{V_i^d}\right) \quad (16)$$

$$Q_i = -|P_i \tan \phi_i|. \quad (17)$$

<sup>6</sup>Where the minus signs indicate that the active and reactive powers are extracted from the AC system.

where  $\phi_i$  is the power factor angle of the converter.

Thus far we have 14 independent equations from the AC side and three additional independent equations from the DC network are:

$$\begin{bmatrix} 1 & 0 & 1 \\ 1 & 1 & 0 \end{bmatrix} \begin{bmatrix} I_{74} \\ I_{79} \\ I_{94} \end{bmatrix} = \begin{bmatrix} -I_4^d \\ I_7^d \end{bmatrix} \quad (18)$$

$$V_4^d I_4^d + V_7^d I_7^d - V_9^d I_9^d - I_{79}^2 R_{79} - I_{74}^2 R_{47} - I_{94}^2 R_{49} = 0 \quad (19)$$

One is not guaranteed a feasible solution for arbitrary settings of the  $(P, V)$ s at the PV buses and the  $(P, Q)$ s settings at the load buses. In order to find a feasible loadflow solution the following approach was followed:

1. Define  $\mathbf{F}(\mathbf{x})$  as being a mismatch vector. This vector element-wise gives the mismatch of each of the 17 independent loadflow equations from zero. For a feasible solution  $\mathbf{F}(\mathbf{x}) = \mathbf{0}$ .
2. Making the  $V$  of the slack bus, the  $(P, V)$ s of the PV buses, free, while keeping the  $(P, Q)$ s of the loads (from [4]) fixed, one can minimize  $J(\mathbf{x}) = \mathbf{F}(\mathbf{x})^T \mathbf{F}(\mathbf{x})$  in order to obtain a feasible solution.
3. The constraints on this optimization problem are:
  - $P_i \leq S_{ni}$  for  $i = \{1, 2, 3\}$ , where  $S_{ni}$  is the rated apparent power of the applicable machine. (see table 1);
  - $I_9^d > 0$  while at least one of the other two DC currents need to be strictly greater than zero, i.e.  $I_4^d$  or  $I_7^d > 0$  and  $I_7^d$  or  $I_4^d \geq 0$ .

In column 2 of Table 3 a feasible loadflow solution is shown. Column 3 of the table shows a feasible solution for the system when the active and reactive load at bus 6 was increased. Column 4 of the aforementioned table shows a feasible loadflow solution when only the reactive power at bus 6 was increased. We note that for the latter case the voltage at bus 6 dropped significantly from 0.99p.u. to 0.85p.u. We also note that the reactive generation (imaginary part of  $S_3$ ) in AC subsystem 3 increased from 0.0018p.u. to 0.8677p.u. in order to meet the reactive power demand. It is observed that in an AC subsystem there need to be enough local reactive power supply capability. In column 3 it is shown that the voltage drop at bus 6 is 0.09p.u. The active and reactive generation of generator 3 increased to help meet the load, while the active power import from the other two AC subsystems stays nearly the same. (see real parts of  $S_4$ ,  $S_7$  and the currents  $I_4^d$ ,  $I_7^d$ ).

### 5.5 Optimal DC power routing

Optimization of the setpoints  $E_{ij}^{sp}$  can be done in order to minimize the  $I^2 R$  losses on the DC lines. The energy

absorbed (or injected) by the shunt devices. It is returned to the ADC network through systematic manipulation described in Appendix 3 Section 7. As a first iteration this routing problem was completely decoupled from the loadflow problem. The inputs for this optimization problem are  $V_i^d$  and  $I_i^d$  (for  $i = \{4, 7, 9\}$ ). The problem is formulated as follows:

$$\min_{E_{ij}, I_{ij}} (I_{74}^2 R_{47})^2 + (I_{79}^2 R_{79})^2 + (I_{94}^2 R_{49})^2 + \sum_i \sum_{j \in C_i} (P_{ij}^{dev9\&10})^2 \quad (20)$$

$$\text{subject to } \sum_i (P_i^d + \sum_{j \in C_i} P_{ij}^{dev9\&10}) + I_{74}^2 R_{47} + I_{79}^2 R_{79} + I_{94}^2 R_{49} = 0 \quad (21)$$

The terms in the cost function (20) have dimension of  $[VA]^2$ . This choice is necessitated because the magnitude of power handled by the series and shunt control devices should be limited. If the dimension was taken to be  $[VA]$  the cost function would not have been bounded from below.

The trivial solution for this problem<sup>7</sup> is  $I_{ij} = 0$  and  $E_{ij} = V_i^d$ , which would have been the result in steady state if the  $I^2 R$  losses were not incorporated into the cost function. The proposed cost function can be replaced or enhanced by additional terms that will reward transmission owners. In Table 4 the result of this static optimization is shown, where the initial guess was the trivial solution previously discussed.

The extra flexibility that device 9 and 10 provides, may make it feasible to control the flow optimally (in terms of the utilization of the wires) on the DC network. This however needs to be investigated further. The dynamic simulation section however was implemented without running the optimal DC power routing problem. In such cases  $E_{ij}^{sp}$  was taken to be the DC bus voltage at the converter stations, which were obtained from the loadflow analysis.

### 5.6 Operation and Control

The following primary control devices form part of the system under investigation:

- Generator excitation control implemented as a Type 1 IEEE regulator [3].
- Hydraulic turbine and governor primary controllers.
- Inverter-Converter with which we can control the DC side voltages and power.
- Series branch control of power flow on the DC bulk transmission lines.

<sup>7</sup>Remember that shunt branch is normally used to smooth out transients on the ADC side. Most of the time  $I_{ij}$  is 0.

Table 3: Feasible solutions for the loadflow problem. All angles are expressed in degrees and voltages are in per unit (unless otherwise indicated). Flow into the AC network indicates positive apparent power. All currents are in A.

| Variable              | Unperturbed              | $\Delta P_6 = -.3p.u., \Delta Q_6 = -.3p.u$ | $\Delta P_6 = 0, \Delta Q_6 = -.6p.u.,$ |
|-----------------------|--------------------------|---------------------------------------------|-----------------------------------------|
| $V_1 \angle \theta_1$ | 1.0817 $\angle$ 0        | 1.0811 $\angle$ 0.0000                      | 1.0819 $\angle$ 0.0000                  |
| $V_2 \angle \theta_2$ | 1.0798 $\angle$ 4.8965   | 1.0801 $\angle$ 4.0666                      | 1.0802 $\angle$ 4.9019                  |
| $V_3 \angle \theta_3$ | 1.0605 $\angle$ 0.0726   | 1.0910 $\angle$ 0.0543                      | 1.1069 $\angle$ 0.0688                  |
| $V_4 \angle \theta_4$ | 1.0926 $\angle$ -4.2382  | 1.0922 $\angle$ -4.2341                     | 1.0927 $\angle$ -4.2390                 |
| $V_5 \angle \theta_5$ | 1.0433 $\angle$ -9.3827  | 1.0428 $\angle$ -9.3825                     | 1.0434 $\angle$ -9.3822                 |
| $V_6 \angle \theta_6$ | .99367 $\angle$ -9.0395  | 0.9026 $\angle$ -13.1510                    | 0.8584 $\angle$ -8.7921                 |
| $V_7 \angle \theta_7$ | 1.0941 $\angle$ 0.81413  | 1.0930 $\angle$ -0.0552                     | 1.0944 $\angle$ 0.8166                  |
| $V_8 \angle \theta_8$ | 1.0663 $\angle$ -2.6131  | 1.0651 $\angle$ -3.4896                     | 1.0665 $\angle$ -2.6092                 |
| $V_9 \angle \theta_9$ | 1.0606 $\angle$ -0.95609 | 1.0603 $\angle$ -1.9252                     | 1.0611 $\angle$ -1.0282                 |
| $S_1$                 | 1.5164 - $j$ 0.14801     | 1.5135 - $j$ 0.1521                         | 1.5170 - $j$ 0.1472                     |
| $S_2$                 | 1.3457 - $j$ 0.19973     | 1.3577 - $j$ 0.1745                         | 1.3475 - $j$ 0.1971                     |
| $S_3$                 | 0.3446 + $j$ 0.00183     | 0.6818 + $j$ 0.5848                         | 0.3837 + $j$ 0.8677                     |
| $S_4$                 | -0.2505 + $j$ 0.80129    | -0.2476 + $j$ 0.8053                        | -0.2512 + $j$ 0.8005                    |
| $S_5$                 | -1.2500 - $j$ 0.40422    | -1.2500 - $j$ 0.4043                        | -1.2500 - $j$ 0.4042                    |
| $S_6$                 | -0.9000 - $j$ 0.12326    | -1.2000 - $j$ 0.4542                        | -0.9000 - $j$ 0.7681                    |
| $S_7$                 | -0.3377 + $j$ 0.63202    | -0.3497 + $j$ 0.6083                        | -0.3395 + $j$ 0.6295                    |
| $S_8$                 | -1.0000 - $j$ 0.26529    | -1.0000 - $j$ 0.2655                        | -1.0000 - $j$ 0.2653                    |
| $S_9$                 | 0.58797 + $j$ 0.26969    | 0.5970 + $j$ 0.2527                         | 0.5904 + $j$ 0.2665                     |
| $V_4^d$ (kV)          | 663.87                   | 663.334                                     | 664.07                                  |
| $I_4^d$               | 37.738                   | 37.328                                      | 37.8250                                 |
| $\alpha_4$            | 10.018                   | 10.1816                                     | 9.9525                                  |
| $V_7^d$ (kV)          | 663.86                   | 663.332                                     | 664.06                                  |
| $I_7^d$               | 50.873                   | 52.7140                                     | 51.1220                                 |
| $\alpha_7$            | 7.9102                   | 7.5984                                      | 7.8489                                  |
| $V_9^d$ (kV)          | 663.54                   | 662.999                                     | 663.73                                  |
| $I_9^d$               | 88.611                   | 90.0420                                     | 88.9470                                 |
| $\alpha_9$            | 167.03                   | 166.77                                      | 166.9600                                |

Table 4: Optimal DC power routing results when iron losses were taken into consideration and not. All values are expressed as ratios of  $E_{max} = 618.63kV$  and  $I_{max} 91.833A$ . The loadflow data used for the creation of this table are when inverter-converter station 4 is operating as an inverter (current is reversed in Figure 5.1).

| Subscript                   | (4, 7)    | (7, 4)     | (7, 9)     | (9, 7)    | (9, 4)     | (4, 9)     |
|-----------------------------|-----------|------------|------------|-----------|------------|------------|
| $E$ (w/ironloss)            | 0.99833   | 4.99872    | 0.99977    | 0.99954   | 1.9003     | 1          |
| $E$ (wo/ironloss)           | 0.99895   | 4          | 1          | 0.99947   | 0.99937    | 0.99892    |
| $\mathcal{I}$ (w/ironloss)  | 7.0648e-4 | -7.8615e-5 | 5.9664e-5  | 1.0012e-4 | 2.8655e-4  | -1.0892e-4 |
| $\mathcal{I}$ (wo/ironloss) | 1.8945e-8 | -1.9103e-7 | -2.3194e-8 | 1.1385e-7 | -1.8003e-7 | 1.9216e-8  |



- Shunt branch control of transient energy drainage (or injection) from (or into) the DC bulk transmission lines.

The Control Center is responsible for computing the following during their steady state analysis:

- The AC/DC loadflow for a given load profile (e.g.  $P_i$ ,  $Q_i$ ,  $V_i$ ,  $\theta_i$  and  $\alpha_i$ )
- $E_{ij}$  and  $\mathcal{I}_{ij}$  are then computed from the optimal DC power routing problem.

Dynamical operation of the system will proceed as follows:

- Control Center compute new steady state setpoints for the desired load profile and/or the current network topology, after the system has been perturbed.
- These new setpoints are communicated to the subsystems, in a very short time relative to the system transient.
- Steady state control then ensues around these new setpoints.
- The difference in energy between the old and new equilibria must be drained (or injected) from (or into) the system at the appropriate locations, in order to eliminate multi-area transient swings that might ensue. (Appendix 3, Section 3.7).

When computing the new ADC loadflow we have no guarantee that a solution exist with the specified  $(P, V)$ 's at the  $PV$  buses. Letting  $P_i$  and  $V_i$  (for  $i = \{1, 2, 3\}$ ) be free parameters, and following the same approach that was followed when an unperturbed feasible loadflow solution was sought, new setpoint values for  $P_1, V_1, P_2, V_2, P_3, V_3$  are obtained for the given load profile.

### 5.7 Simulated event

The validity of the simulation model was tested by simulating the nine bus example, but with devices 9 and 10 removed. The resulting MDC system has no AC interconnections between the AC buses, the areas thus not operate in synchrony. For this test we have that  $\Delta_{ij} = 0$ , and  $\mathcal{I}_{ij} = 0$  which unfortunately leaves out some of the most important innovations.

Due to the number of assumptions that were made while developing the MDC DAE model, it was found that using the "ode15s.m" numerical integration tool in Matlab<sup>8</sup>, that the calculated initial conditions of the states (obtained from the loadflow solution and setting the time derivatives to zero), did not result in a bumpless simulation start-up. The transients however die out and the simulation converges to a slightly modified version of the loadflow solution. See Figures 5.3 and 5.4 for a dynamic response of

<sup>8</sup>This tool can solve DAE models of index 1.

the system towards the slightly modified loadflow solution.

The transients in the DC lines are near non-oscillatory compared to the generator DQ-Axis currents. This can be observed from Figures 5.5 - 5.7. This observation is especially clear in Figure 5.7.

Thus it appears that even without devices 9 and 10 included this MDC configuration (with no AC line interconnections between AC areas) helps in confining the AC area transients to its own specific area. The addition of devices 9 and 10, with their appropriate control laws will limit the transient effect on the DC lines as well as aid in controlling the power flow from area to area more accurately.

This paper is an exploration of how a more effective overall power system could be devised using today's technology and its powerful advancement expected to be reached in the near future, instead of just fitting such improvements into the existing system, as is usually done. This makes demonstration quite difficult at this stage. So what we are offering here is an example written in the framework of current technology. Still we are able to demonstrate in this paper some improvements in this framework.

## 6 Conclusion

*This is a truly novel approach which suppresses the usual system wide transient dynamics and assures a smooth and fast shift from one steady state condition to the next one following a sudden system change or a disturbed period.*

*The price is the use of potentially expensive power electronic devices [9] [10] on each of the bulk transmission lines. This may be too high a price for just smoothing out occasional sudden changes of system composition or disturbed conditions but it has a much wider role. It would also allow to flatten the loading pattern of the entire bulk transmission system to nearly uniform percentage loading bulk line by bulk line. This means eliminating traffic jams i.e. congestion. This would be a truly major relief for the on line trading problem allowing uniform relative loading of all the bulk lines which slide along automatically and virtually instantly with the waves of the across the network trading.*

*It seems achievable relatively easily with the speedup of computation currently in progress and assuming the availability of equipment described here. Of course virtually instantaneous is still not instantaneous, so minor fringe fluctuations need to be expected and dealt with.*

*This new approach is particularly useful when the transient swings would take the system into an unstable region in the system state space, thus resulting in system*

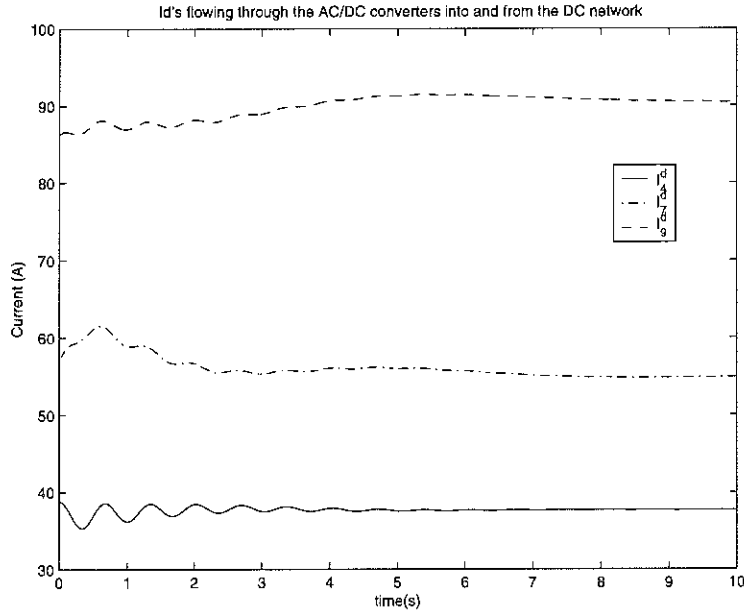


Figure 5.4: Dynamic response of the currents flowing through the inverter-converter stations into and out of the DC network. The perturbation is in the form of a non-bumpless simulation startup.

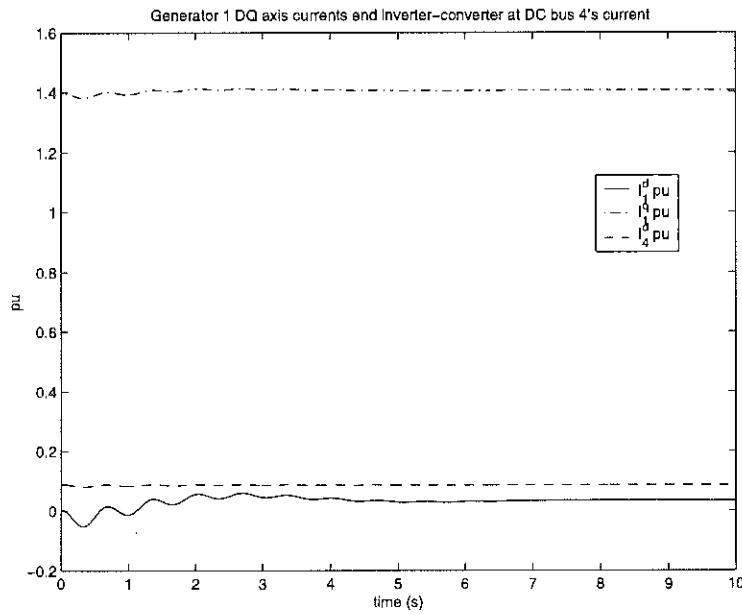


Figure 5.5: Dynamic response of the per unit DQ-Axis currents of generator 1 and  $I_4^d$  ( $I_{base} = \frac{100MVA}{230kV}$ ). The perturbation is in the form of a non-bumpless simulation startup.

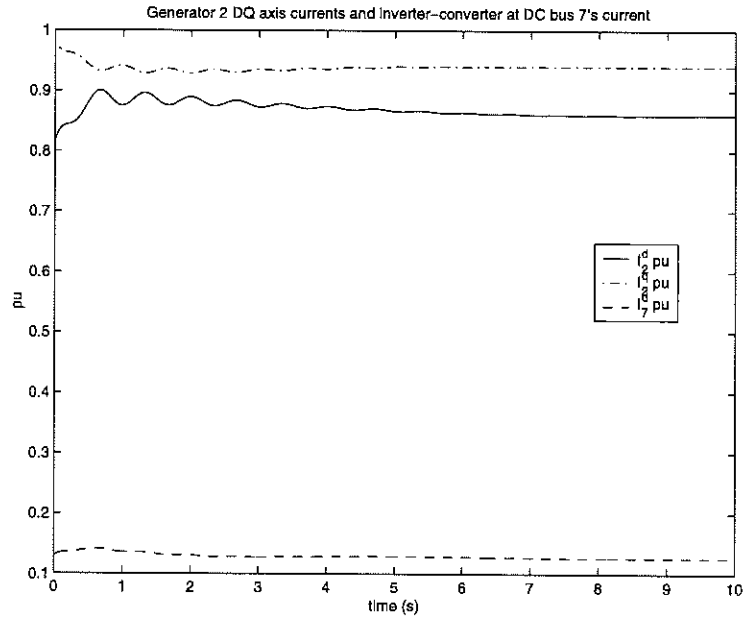


Figure 5.6: Dynamic response of the per unit DQ-Axis currents of generator 2 and  $I_7^d$  ( $I_{base} = \frac{100 MVA}{230 kV}$ ). The perturbation is in the form of a non-bumpless simulation startup.

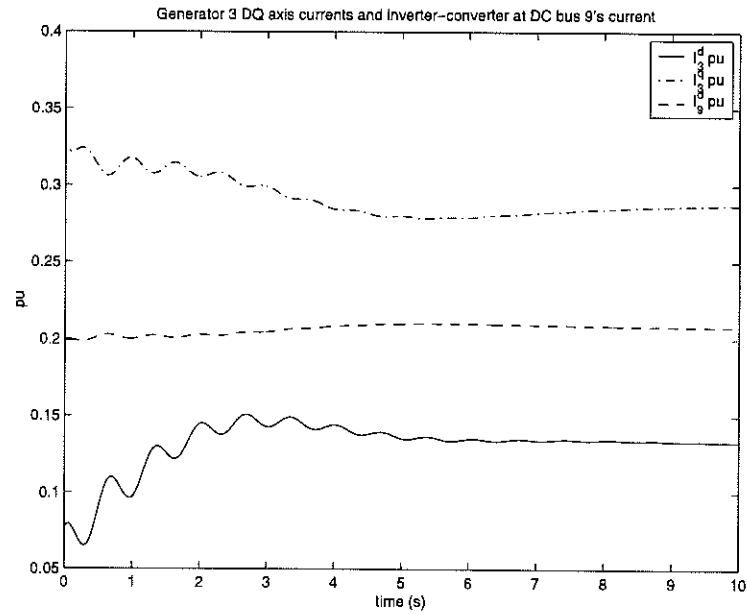


Figure 5.7: Dynamic response of the per unit DQ-Axis currents of generator 3 and  $I_9^d$  ( $I_{base} = \frac{100 MVA}{230 kV}$ ). The perturbation is in the form of a non-bumpless simulation startup.

breakup even though the steady state of the new system configuration after the change is stable. By eliminating the transients and taking the system directly to the new operating condition on the transmission lines the transient breakup is essentially pushed out of the picture.

Note that this kind of floating operation would be implemented by the control centers-commodities exchange combination residing on:

1. The bulk power transmission side terminal voltage of the converter-inverter equipment [6] at the bulk transmission buses [2]. These voltages may or may not be fixed.
2. The series flow control voltage  $\Delta$  at the bulk power lines [1].
3. Shunt control of transient energy at the bulk power lines.

There would be almost no transients but with 5 minute trading the load flow picture would be like the surface of a lake exited by, say, sail boats.

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## Appendix #1: Breaking up a disabled local subtransmission system: Systemic load control.

A disabled subtransmission system, i.e. with insufficient generation to carry on within feasible frequency and voltage range, will need to be broken up and the detached sub-segments will be connected to neighboring systems. This is more or less traditional but, while it normally involves temporary blackouts with ad hoc separations, synchronizations etc. schemes, with the new type of equipment it could be carried out smoothly with at most virtually instantaneous blackout periods on the order of a few seconds. It would be necessary to disconnect all the small IPP's on the system when the connection at the AC bus opens.

This can be achieved by the following means.

1. Predesigned breakup schemes for each local subtransmission section will be available in CC memory storage potentially in a number of varieties. The current composition of the subtransmission system can be used by CC to pick the applicable varieties.
2. As part of the preplanned schemes, emergency control can act almost instantly to select a desirable and feasible sequence of switching actions to break up the local subtransmission system into separate subsegments by simultaneous (but not synchronized) circuit breaker operations, which would be automatically ordered and carried out by the applicable programs. All this would happen in the order of a second, without human interference.
3. Again, automatically, the segments which have no generation would be reconnected to their various neighboring subtransmission segments as ordered by the prearranged program for the emergency control. Instant reconnection is possible because of the absence of generation in the broken segment created in the breakup. (small, IPP feedback generators will disconnect automatically and be later reconnected)

So all the load of the disabled subtransmission section is now again part of the overall system, it is connected to the top ADC bulk transmission system. The customers on the disabled sector have experienced only a brief (order of seconds) blackout.

Also now the management of the emergency on the ADC top bulk transmission system can proceed.

## Appendix #2: A thought experiment type. An example of draining of transient energy

The Control Center orders to change the #1 (Fig. 3.1) of a Type [1] building block (Fig. 3.2) to a different steady state #2 (Fig. 3.1).

The objective is to make the change “virtually” instantaneous.

From the CC analysis, the value of the variables (not just the controls) shown for steady states #1 and #2 will be known as shown in Fig. A.1 and A.2 including the two controls, 1.)  $m', m''$  and 2.) the drainage current  $I'_1, I''_1$ . The latter of course is zero in the steady state.

The hitch is that because the main line current  $I_{ji}$  flows through the line inductance,  $L$ , it can not physically be changed instantly i.e.

$$I_{ji} = I'_{ji} \text{ just after the switch}$$

Our aim is to move  $I_{ji}$  from  $I'_{ji}$  to the value  $I''_{ji}$  as fast as possible by draining the excess (or shortage) magnetic energy from or to capacitor storage as fast as possible.

A somewhat similar situation exists in conjunction to the voltage  $V_i$  and  $V_j$  because of their connection to generator excitation and inertia. To make this simple we will initially assume that  $V'_i = \text{const}$  and  $V''_j = \text{const}$ . This assumption can be materialized by Type [3] and [6] control.

State immediately after switching

$$\Delta E'_i \rightarrow \Delta E''$$

considering that  $I_{ji} = I'_{ji}$  is flowing through the line inductance,  $L$ , and hence it can not change discontinuously there still will be  $I_{ji} = I'_{ji}$  immediately after the switch of  $\Delta E'_i \rightarrow \Delta E''$ .

So a transient through the system will result.

To avoid this we need to open the drain line (by closing the drain line thyristor switch) into the drain capacitor which is empty. Since the circuit of the draining capacitances (the shunt control branch) has no significant inductance the drainage current  $I_{Li}$  can change instantly from zero to  $I''_{i1} = I'_{ji} - I''_{ji}$  (assuming  $I'_{ji} > I''_{ji}$ ). Then the immediate post change status as shown Fig. A.3 this is the state of the system right after the change to the newly ordered equilibrium.

In this condition:

1. The desired series branch current  $I''_i$  reaches its intended value  $I''_i$  instantly controlled by the voltage

$\Delta E''_i$ , generated (power electronically) from  $E_{i1}$  in Box 1.

2. The current generated in the  $j$  terminal is  $I'_{ji}$  matches the current just before the change. This is required and enforced by the line inductance over which current must flow.

So there is momentary balance but there is the extra magnetic energy in the line current (and the capacitive charge on the line). The later will play little part here. This current can be controlled by the  $\Delta E_{i1}$  control voltage generated as shown in the Figure A.3.

Now our problem is to drain the excess magnetic energy out of the transmission line using the controls  $\Delta E_i$  and  $\Delta E_{i1}$ .

1. Of these two  $\Delta E_i$  on the main  $I_i$  branch will be used mainly to control the  $I_i$  current and to keep it on the  $I'_i$  value during the quick transmission period after the change. This means that the main current transfer is virtually undisturbed, it changes to its new equilibrium value smoothly and “instantly”. To avoid interference the Box 1 equipment may need to rectify out current flow from bus  $i$  to the branching point  $E_i$  just during the transition.
2. The control on the other side is more complicated. This basically is an LC circuit in a nonstationary position.

In the immediate post switching period with  $V'_i$  and  $V_i$  held fixed by the outside circuits (Type [3] and [6] block control) the voltages  $\Delta E_i$  and  $\Delta E_{i1}$  generated within the two power electronics Boxes 1 and 2 will control the currents  $I_i$  and  $I_{i1}$  dynamically as dictated by  $\Delta E_i \Delta E_{i1}$  and the electromagnetic energy initially contained in the impedance  $L$  in the form of current  $I_{ji}$  line. Initially  $I_{ji} = I'_{ji}$ .

The dynamic part of the circuit then consists of the LC circuit in one line.

The line voltage on the line capacitance will change only slightly on the order of voltage drop along the line so the dominant dynamic capacitor will be  $C_i$  the one in Box 2. (Fig. A.4)

So the dynamic circuit is  $L_{ij}$  and  $C_i$  with initial state  $E_c^0 = 0$ ,  $I_{ji}^0 = I'_i - I''_i$  where  $I'_i$  is a constant, kept that way by control  $\Delta E_i$ .

This leaves simply an LC circuit in a non static condition.

The resulting transient will be the typical damped (because of the line resistance) sine waves of the voltage  $E_i$  and the current  $I_{ji} - I''_i$  with a displacement (also

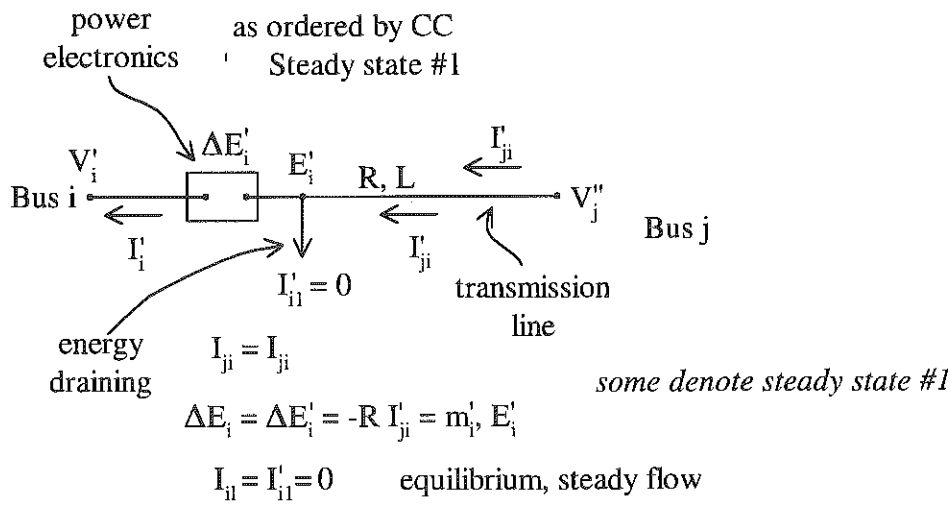
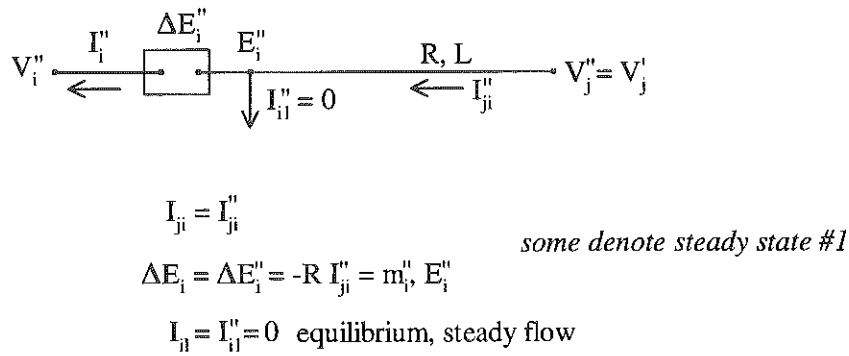


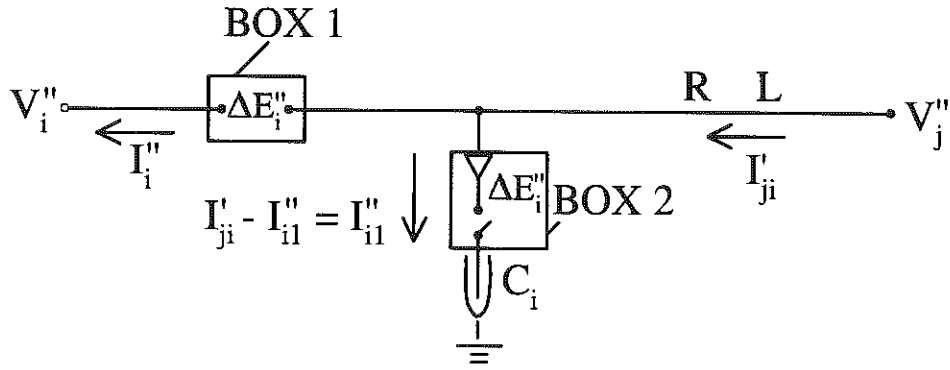
Figure A.1: Steady state #1. Abstracted from Fig. A.3.

" Steady State #2



Note: E or V without primes denote the state variable with ' or '' a specific value

Figure A.2: Steady state #2.



$$I_{ji} = I_{ji}'$$

$$\Delta E_i = \Delta E_i'' = -R I_{ji}'' = m_i'' I_i''$$

$$I_i = I_{i1}'' = I_{ji}' - I_{ji}''$$

Figure A.3: State immediately after switching  $V_i' \rightarrow V_i''$   $V_j' \rightarrow V_j''$  on CC order.

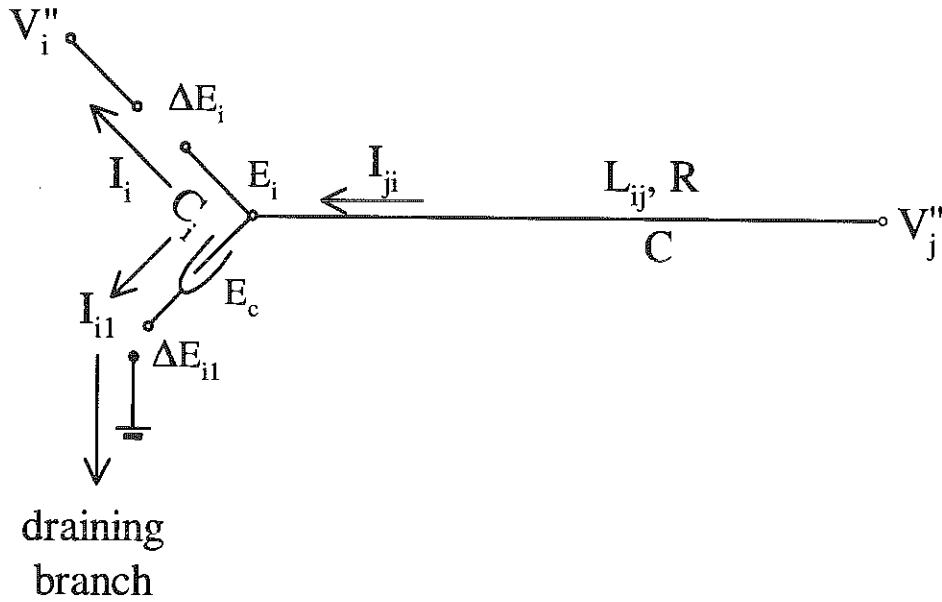


Figure A.4: Immediately after closing.

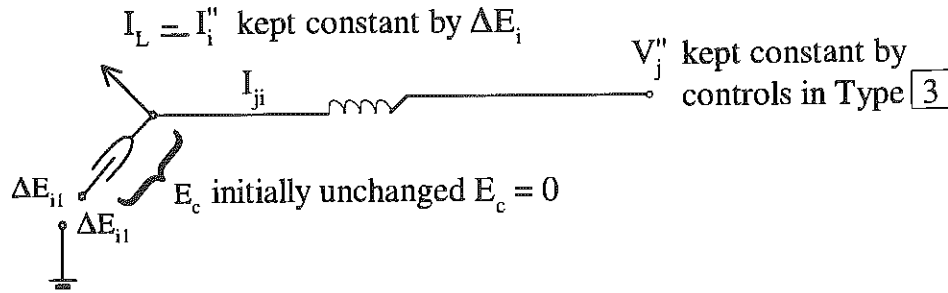


Figure A.5: Alternate use of Fig. A.4.

damped) because the initial mismatch of the instantaneous voltage and current, as also commonly encountered in LC transients in AC lines.

This is a very fast oscillation and the current  $I_{i1}$  will reach  $I_{i1} = 0$  in less than one half cycle of this oscillation at which time the draining branch can be separated effect in Box 2 leaving the  $ij$  line in its new steady,  $I_{ij}''$ , state virtually instantaneously after the CC command. The drainage branch is left with a charged capacitor. The latter can be utilized in a way described in Appendix 3. Section 3.7.

Some numerical results are shown in Section 5 earlier.

Note: The draining current is sort of guided or constrained to a channel by keeping the bus voltages  $V_i V_j$  fixed during the draining process by the electronics in the converter [6]. A back flow barrier (rectifier) on the series circuit may also be needed during the draining process.

The above of course is just one example, possibly the easiest yet most unusual with the assumption  $I_{ij}' > I_{ij}''$  or with both equilibrium currents flowing into bus  $i$ . Under other assumptions like  $I_{ij} < I_i''$  or  $I_{ij}' = -I_{ij}''$ , or cases where  $V_i$  rather than  $I_{ij}$  is the target of the change, somewhat more but feasible strategies will apply. These will need to be kept in the CC memory.

All these cases can be solved by the manner of study shown here, the mathematical relations for which are simple to write down on the homework level as they would be in this case based on this analysis.

Some additional tools which may be included would be 1.) control equipment ( $1_2, 1_3$ ) on both ends of the line or 2.) using the other energy storage in mechanical form in blocks Type 3 in kinetic and heat energy form in the generation and the subtransmission. Energy withdrawal here takes the form of brief and minor droppings of frequency—the withdrawal from  $V_i$  through  $E$  can still be done through Box 2 and  $\Delta E_{i1}$ .

Let us again emphasize that this “exploration” is not aimed at solutions which can be economically built within today’s technology. For instance the above solution could be physically built with today’s technology—using brute force transformation (converter-transformer-taps-inverter) but its economy and speed would be questionable. Economy is not the issue here. We are trying to find new ways of approaches with new type of thinking which will lead us to truly better solutions made possible by expected major advances of technology (rather than just pitching up existing solutions).

### Appendix #3: Summary of operation of the building block sets

#### The Control Center

To start with the list in the {C} block for Control Center in Fig. 3.4 enumerates the major tasks to be performed. This will be a major task in developing the proposed system organization (Fig. 3.4). Preliminary explorations indicate that present day technology could handle some of these tasks but not all of them. On the other hand an order of magnitude speedup is expected to result from current new approaches (such as computation based on quantum mechanic control) Once this is achieved the objective set for CC can be achieved also. Furthermore additional very major speedups can result from clever design of the mathematical formulations and algorithmic processes for the various tasks in the CC block of Fig. 3.4. The major simplifications resulting from working with DC rather than AC circuits is another encouraging factor.

All this seems to justify this preliminary exploration of the system along the lines of Fig. 3.4, which introduces a number of unconventional ideas for operating the power system.

In this appendix characteristic qualities of the eight buses during blocks will be summarized as a foundation for further studies.



### 3.1 Operation and Control Problems of the Type [1] building block, the ADC transmission lines.

The role of this building block [1] is  $j$  to keep the DC circuit current flowing from bus  $j$  to  $i$ ,  $I_{ij}$ , at the value assigned by the Control Center  $i$  to each individual line  $L_{ij}$ .

Control to satisfy the assignment of CC is strictly local within the individual Type [1] block.

*Control tools.* (see Fig. 3.2) for line  $ij$  are:

1. *Serial control* which inserts a voltage jump  $\Delta E_{ij}$  into the active or  $i$  end of the line tapchanger fashion (Fig. 3.2).
2. *Shunt controls* (Fig. 3.2) which draws, in or out of the line  $ij$ , a given amount of energy  $\Delta W_{ij}$  from the  $i$  end of line  $ij$ . (Appendix 2)

It is assumed that all controls of each line  $ij$  is concentrated at one end  $i$  while the states at the  $j$  end are inputs from bus  $j$ .

*Control Inputs to block [1]:*

1. The assignment from CC is coming at fixed time intervals  $\Delta t$ . For line  $ij$  it consists of only  $I_{ij}$ , the DC component of the line current which carries the DC power  $P_{ij}$  to flow from bus  $ij$ , to bus  $i$ .
2. *Local measurements of*
  - (a)  $V_i$  and  $V_j$  the voltages of the buses  $i$  and  $j$  respectively.
  - (b) The local measurements of the current at the ends  $i$  and  $j$ .

Note that the controls of building blocks [1]<sub>ij</sub> has no responsibility or capability for controlling the voltages  $V_i$  and  $V_j$ . These are the responsibility of Blocks [3]<sub>k</sub>, the generators. Thus when controlling the line current  $I_{ij}$  the voltages  $V_i$ ,  $V_j$  are just inputs. This type of decoupling makes the distributed control proposed here simple, provided it is practical i.e. feasible. See Appendix 2.

*Operation and control of Block [1]<sub>ij</sub>*

- (a)  $I_{ij}$  takes care of the local flow dispatch of the system. While the static  $I_{DC}$  is flowing however a substantial quantity of electromagnetic energy,  $W_{ij}$ , is stored in the inductances and capacitances of the line  $ij$ . This energy is also static until the current  $I_{DC}$  and voltage  $EDC$  is changing.

When  $I_{DC}$  and  $V_{DC}$  are changing however then this energy,  $W_{ij}$ , also has to change. If no control steps are taken then these stored energies will

dissolve in a system wide transient which would need to be dealt with—a rather complicated task. An alternative approach is proposed here. Let us drain out this trapped energy from the individual  $ij$  lines into capacitive storage section 3.7 below and Appendix 2, line by line. If this can be accomplished then the system will move on from quasi steady state to quasi steady state smoothly without transient (of course 100% accuracy is not possible so some perturbation level transient will still persist and, hopefully damp out quietly). The control tool to be used for this is the shunt branch control proposed here.

- (b) The *shunt control of Block [1]<sub>ij</sub>*. To drain out the trapped energy in line  $ij$  it is first necessary to establish its size and for that purpose one needs to establish its composition. In a steady system state with known  $V_i$ ,  $V_j$ ,  $I_{ij}$  and  $L$  and  $C$  per mile of line  $ij$  plus the line length the stored energy in  $L$  and  $C$  can be readily computed. Let us say this steady state value is  $W_{ij}$ . Now if the CC assigns a different quasi static state over step  $\Delta t$ , or a major shift results because of a disturbance like losing a line or generator, then seeking the new stored energy a shift of  $\Delta W_{ij}$  in the stored energy is needed. Thus the change  $\Delta W_{ij}$  in line  $ij$  is readily computed provided the system is kept in a steady state before and after the shift over time  $\Delta t$ —which is the condition we try to achieve with current or future speed or equipment.

This  $\Delta W_{ij}$  excess energy then will be drained into or out of a storage capacitor bank, in the course of the shunt control operation, as discussed in the section devoted to segment ② in the figure 3.2 devoted to the organization of the draining capacitor equipment.

Since energy would be drained by the shunt branches, in both directions (either charge or discharge) and any particular bus in [2]<sub>j</sub> will connect to several lines [1]<sub>ij</sub>. The storage capacitors of these would logically be combined in a station, bus  $k$  storage capacitor as indicated in the Table in the box below {1} and {2}. This station storage capacitor will still need to have a structure allowing enough flexibility of connections. On the other hand since drainage would vary between both direction statistically canceling, the overall size of the static capacitor bank should turn out manageable.

#### Equipment wise

The Serial Control requires a tapchanger type control with a small range of control range (possibly less than 15% of the full voltage) but it should be very fast and smooth. Brute force converter-tap changer-inverter solutions should be possible but probably too slow even utilizing

power electronic devices (as I believe they do in England or Japan) instead of the US mechanical ones—(about 1 minute per operation). Fast power electronic approaches will be developed or even exist already. (see the example in Section 5).

The *shunt control* requires some very fast electronic switching to connect the  $i$  end to an energy storage volume of a proper capacity which can be regulated. It may be possible to construct something of this nature now with potential large speedup in the future.

Since both series and shunt controls will involve power electronic equipment it is probable that they will be merged into *one single piece of equipment*. (see the example).

*Ultimately* then the feasibility and success of this proposed approach hinges on the feasibility of providing equipment which can perform fast enough (“virtually instantaneously”) compared to the rate of variation on the events which are being controlled. A critical item here is the speed with which the Control Center can arrive at a new set of control assignments. The latter will set the lower limit for  $\Delta t$  the sampling time of the operation, it seems questionable whether current equipment can produce such speed, yet there are developments which promise another large step reduction of computation time (in the one order of magnitude range). Considerable effort could produce really large reductions of the Control Center functions. Going DC and avoiding all the time consuming computations connected with reactive power, reactances, AC stability and many others, plus carefully minimizing the computations needed by climate-ring, exploiting the moderate size of changes over  $\Delta t$  or else their “instantaneous” character would result in the future in drastic speedup of CC.

The result would be a smooth, more secure and simpler overall power system.

### 3.2 Operation and Control Problems of the Type [2] building block, the All DC bulk transmission buses

The ADC transmission buses in the set (2) of Type [2] building blocks are quite typical. They are controlwise inactive. The only active role played would be opening and closing the circuit breakers connecting with the bulk transmission lines or blocks [1] provided these are considered. These breakers are counted as part of blocks [2] rather than 1. In addition to the regular block [1] transmission lines a few of the IPP (Independent Power Producers) lines may be connected to the [2] buses, but at this level of voltage they would be considered as parts of the [1]—[2] system although possibly under somewhat different operating rules but still under the control of the CC. The voltage of the buses is controlled

through blocks Type [3] by the generation on [3] and the conversion-inversion equipment in Type [6]. Power flow in and out is controlled by Type [1] series controls and the in and out drainage by the shunt control of Type [1] lines supplied of energy by the capacitor in Type [5]. Of course there is extensive precise and fast communication equipment with the CC in and out.

### 3.3 Operation and Control Problems of the Type [3] building block, The Generation Supporting individual buses

The role (Fig. 3.4) of the building block Type {3} is to

1. Supply the amount of power  $P_k$  flowing into the bulk power system bus  $k$ .
2. Keep the AC bus voltage  $V_{ac}$  at its nominal value which may be altered from time to time by CC depending on system condition.
3. Supply the power needs,  $P_s$ , as they are measured and/or estimated for each segment of ac subtransmission in {4} which is attached to each bulk system bus in {2}. (see Fig. 3.1–3.4).

Type [3] controls the voltage of the internal AC buses of the Type [3] blocks. This bus is feeding (Fig. 3.1) both the bulk transmission Type [2] bus and the segment of subtransmission, [4]. The CC may keep the setting of this voltage on the AC bus in {3}, achieved through [6], fixed at about the rated voltage of the subtransmission network.

Finally, 1 is the bus  $k$  share of the power input  $P_k$  into the bulk power transmission system {1} and {2}.

Let us now look closer at the control of voltage and power flow around [3].

#### 1.) Voltage control

There are two voltages to be controlled

- I. The voltage,  $V_k$ , of the bulk power system bus,  $V_k$ , within {2}.
- II. The voltage,  $V_{ac}$ , of the internal AC bus in the set {3}.

Typically the voltage  $V_k$  of the bulk buses within {2} is controlled by the converter [6] every  $\Delta t$  sec. to the value assigned by CC and the voltage  $V_{ac}$  is assigned a nominal value by CC which may be constant or be changed occasionally, say raised during the daily peak.

There also are two control tools for the two voltages

- I' The generation excitation of the generating equipment at each individual AC bus in {3} which is attached to one specific bulk bus in {2}.
- II' The power electronic equipment [6] in the converter inverter set leading from the AC bus in set {3} to the bulk power transmission bus,  $k$ , within {2}.

It seems reasonable to use the power electronic equipment primarily to control the bulk system bus  $k$  voltage and the generation excitation control mostly for the voltage of the local AC bus [5] in set {3} (Fig. 3.3) which is the source of the subtransmission segment. Of course these controls are interacting so we have a two (or more e.g. when there are several generators in the power plant) dimensional control state space to manage. But this still would be a routine problem to solve.

2.) *Control of Power flow  $P$  into the bulk system bus  $k$  of the segment and of the frequency,  $f_k$ , in the segment,  $k$ .*

So there are again two state variables to control

- I' the power flow  $P_k$  into the bulk transmission system bus,  $k$ .
- II' the frequency  $f_k$  of the segment  $k$  associated with the bulk transmission bus  $k$ .

Typically both of these would be controlled to the assignments of the CC in the basic process of one assignment every  $\Delta t$  seconds although the frequency of the segment may be assigned less frequently. This is a matter to select when developing the CC program.

There also are two control tools

- I' The control valve opening in the generators serving bus  $k$  within the set {2}.
- II' The power electronic equipment [6] at the AC-DC boundary in {2}.

Again it needs to be established in the CC program how these roles would be divided between I' and II' but the use of the power electronic controls to regulate the power flow into the bulk transmission system seems a logical choice. Then if the assigned frequency assignment is tracked by the control valves of the generators this will result in feeding into the subtransmission segment the power it needs to satisfy its load demand at the assigned frequency. This load demand as observed, and reported to CC then becomes one of the inputs into the CC system control.

*Summarizing the control process around {3}*

- 1.) *Local measurements* of states as inputs to the controls.
  - a. Local measurement of voltage  $V_k$  of bus  $k$  in {2}.

- b. The local measurement of the power flow bus by bus from {3} into {2}.
- c. Local measurements of the voltage on the AC bus  $k$  at {3}.
- d. Local measurement of the frequency  $f$  of the AC bus at {3}.
- e. Local measurement of the total power flow into the segment  $k$  of {2}.

2.) *Control setpoints assignment in block Type 3.*

In the course of normal operation from the CC assignment arrive in fixed time intervals  $\Delta t$ . For buses in set {3} they consist of

- 1. Power demand of each bus  $k$  in {2}.
- 2. The AC frequency of the subtransmission segment,  $k$ , in {3}.
- 3. The voltage of each bulk transmission system bus  $k$  in {2}.
- 4. The voltage of the AC bus in the segment,  $k$ , attached to each bus  $k$  in {2}.

3.4 *Operation and Control Problems of the Type [4] building block, the Subtransmission Segment*

The Type [4] set {4} of subtransmission segments are quite conventional AC subtransmission networks, (see Fig. 2.1), with possibly a few isolated DC lines imbedded in them. However they are of a well defined nature

- 1. They are isolated and connected to only one bulk transmission system bus and a single source of power generation (this of course is the basic definition of subtransmission. (see Fig. 2.1).
- 2. These isolated networks have as connection to each other only in ADC through the Type [2] building block, a bulk power transmission bus, (Fig. 3.4), and the generation of this Type [2] bus.
- 3.) The interconnection of AC network, generation, conversion [6] is through a small local and conventional AC bus described separately in set {5} of Type [5].
- 4.) Thus the subtransmission networks are not synchronized and no option exists to do so. Without synchronization the voltage, and power consumption and frequency can be directly and independently regulated by the generation (Type [3]) and conversion (Type [6]) operations.
- 5.) This allows the frequency to be used as an energy storage variable (within appropriately narrow limits of

synchronous time) with mechanical energy storage in generation facilities *in partnership with the capacitor energy storage* on the bulk network side.

6.) All this opens up great new flexibility in system operation and dealing with emergencies.

7.) In case the emergency affects the specific segment itself then a prearranged process (described in Appendix 1) can be used to transfer segments of the affected sub-transmission system to neighbors without synchronization but instead with a mini (seconds) blackout. Even this of course will happen very rarely. One should remember that conventional AC manipulation of transfer also takes time (two was personally doing it)

Overall it would seem that major flexibility can be gained by this approach for distribution with very minor sacrifice.

### 3.5 Operation and Control Problems of the Type [5] building block, short local AC bus

Each subtransmission, {4}, generation, {3}, conversion {6} grouping utilizes an individual and separate, small AC bus for cooperation within the group. This is an entirely conventional small AC bus incorporating the circuit breaker of its connection. Beyond the three basic connections mentioned there could be addition direct connections for some large IPP operations which are not quite large enough to connect to the Type [2] bulk DC buses and also some large loads.

### 3.6 Operation and Control of the Type [6] building block the Conversion-Inversion Operating

The Conversion-Inversion apparatus between AC and DC parts of systems are well developed and understood. It does not seem necessary to take up space at this place and time to discuss them. Developing technology will make it possible to improve and upgrade response time and add a few necessary additional features.

### 3.7 Operation and Control problems of the Type [7] building block. Managing the drainage capacitors for an individual, Type [2] bulk bus

As indicated in the illustrative description of (Appendix) an uncharged capacitor bank would be needed to drain out the excess, transient, current flow from a bulk transmission line. This capacitor needs to be connected and charged and again disconnected charged in a very short time later. Conversely charged capacitor may be needed e.g. to raise the current in a transmission line. To make this kind of operation efficient and reduce the cost it is important to have a set of capacitors both in charged and discharged condition at either polarity and provide the one in the desired condition available at any bulk line and

to connect it at electronic speeds.

Probably what is needed here is fully charged or discharged. The process may leave partially charged or discharged banks so the first step will be to add or take out charge from the capacitor after its action.

Fortunately the required manipulations on the capacitors are inherently extremely fast and flexible provided the following structural and equipmental rules are followed.

1. Organize a set of capacitors as set {7} of building blocks Type [7], (see Fig. 3.4), for each bulk transmission block type [2] rather than for individual bulk transmission lines Type [1].
2. Every capacitor bank (probably all of the same size) must be fully insulated (proper size insulator columns supporting their housing above ground).
3. If so insulated than either terminal of the capacitor can be connected to either + or - poles of any transmission line and/or bus, including even one capacitor terminal to either the + or - conductor and the other to the opposite provided the internal insulation of the capacitor is for the full + to - voltage (Depending on the manipulation prescribed capacitors insulated for + to 0 or - to 0 may suffice).
4. Remember that it takes very minimal energy (involving only the capacitance of the capacitor cases to ground) to connect only one end of the capacitor.
5. It then takes a complex but feasible bookkeeping structure of capacitor banks and connecting waves insulated for full voltage and organized into a network with electronic type switching to
  - (a) Keep the necessary number of each connection ready to be instantly connectable to any of the transmission lines Type [1] when and where needed.
  - (b) To build such a managing setup for each bus in a project which is feasible in the framework of present technology but challenging and require careful thinking.

The alternative of building a much simpler bookkeeping system for a smaller set of capacitors firmly assigned to each particular line ending remains open of course. In this alternative the capacitor set {7} becomes disjoint between line ends at each bus just like the set of lines {1} itself is disjoint.

Either way the set of draining capacitors is the foundation for draining the transient energy out of the bulk transmission lines line by line i.e. block by block.

*3.8 Operation and control problems of the Type [8] building block. Managing of the scattered smaller IPP's within the subtransmission and distribution networks*

This important problem will not be discussed within this paper because of its rather different nature from the other contents.

Discussion by Lester H. Fink of

## Exploring the Potentials of an All DC (ADC) Bulk Power System

by John Zaborszky, Maria Ilic, and Ernst Scholtz

**Lester H. Fink:** Professor Zaborszky has presented a thoughtful, detailed overview of a likely candidate bulk power transmission system of the future. His paper deserves careful and thoughtful review by all those interested, not only in the hardware of the future system, but also by all who are concerned with its operation and control.

There are two aspects of this prevision that should be noted. First, it does not constitute a regression to the "battle of the currents" of a century ago, but rather a natural next stage in the ongoing evolution of electric power transmission technology. Second, the first steps in this next stage have already been taken.

To the first point: By the last decade of the nineteenth century, the major cities of the industrialized world were peppered with a bewildering variety of electric power systems, employing various types of engines, dynamos, and turbines to power a like diversity of generators, each of which were designed to serve a particular type of load - arc lighting for streets and large buildings, incandescent lighting for homes (all competing more or less successfully with gas lighting), traction loads, stationary motor loads, etc. Each of these "systems" required a different "type" of electric energy. By 1895, Philadelphia had about twenty electric companies with distribution systems operating at 100-V and 500-V two-wire dc and 220-V three-wire dc; single-phase, two-phase, and three-phase ac; with frequencies of 60, 66, 125, and 133 cycles per second; and feeders at 1000-1200 V and 2000-2400 V. These diverse systems could not be interconnected, were effective over areas of different extensiveness, had diverse reliability records, and were all using all available means of competition, fair or otherwise, to increase their share of the market.

The efforts of a number of inventors resulted in a variety of interface devices that enabled such diverse systems to be interconnected and operated together, including the Bradley Rotary [AC-DC] Converter (1888), the transformer developed by three Hungarian engineers (introduced at the 1885 Industrial Exhibition of Budapest), and the frequency changer. The "universal" system made possible by coordinated application of these devices was demonstrated by Westinghouse at the Chicago Exposition in 1893, and put into practical use by the Niagara Falls system in 1895.

The impact of the universal system was significant at

several levels. At the technical level, it solved a number of vexing problems that resulted in significantly more efficient use of capital plant, since it enabled virtually all generating capacity to be operated in parallel to serve any type of load, taking significant advantage of load diversity, rather than each type of generator being sized to match a peak load that was required only during very short periods. Moreover, the more efficient generators could be fully utilized, with less-efficient generators used only during periods of net system peak. At the corporate level, the universal system provided significant incentive for the merging of competing companies serving overlapping territories, thus again resulting in less redundant capital investment and labor, and leading further to standardization of the bewildering variety of voltages, frequencies, equipment designs, and operating practices, all leading to more economic operation.

A major element contributing to the classical mid-century electric energy system was high-voltage long distance transmission. Initial development of this technology was motivated by circumstances on the Pacific coast, where large urban centers were dependent for power on imported coal, while in the distant inland mountain ranges water power was plentiful. In 1895, the Folsom hydro power plant transmitted 3,000 kW of 60 cycle three-phase current from four GE generators at 11,000 volts over a distance of 20 miles to Sacramento. Within six years, two parallel 60,000 volt transmission lines were carrying 3,000 kW from another hydro power plant over a distance 140 miles to Oakland.

Thus, the "battle of the currents" was decided by the need for flexible utilization, distribution, and long distance bulk transmission of electric power, all of which needs were served uniquely by alternating current technology. At this juncture, a century later, direct current loads are served efficiently via conversion devices at any desired voltage level, and there is no question of reverting to direct current distribution. The major problem now facing us is that of increased capacity for long distance bulk power transmission. AC transmission requirements have now saturated existing corridors, and additional corridors are unavailable. The solution to this problem is to be found in two technologies unavailable 100 years ago: "high temperature" superconducting DC transmission and high voltage DC transmission utilizing power electronics devices.

To the second point: These technologies have been developed over the past thirty years, and initial applications are now in service. The 845 mile Pacific Northwest-Pacific Southwest 800 kV, 1440 MW DC Intertie between the Celilo converter station in Oregon and the Sylmar terminal station near Los Angeles, energized in 1968, is now being upgraded to 1000 kV, 3100 MW, by replacing the 1960 era vacuum tube technology (mercury-arc valves) with solid-state converters (roll in thyristor valves) and controls. For over a decade, Texas has been connected to the rest of the U.S. by a number of back-to-back high voltage AC-DC-AC converters/inverters. Last year, Detroit Edison announced 400 feet of copper wire in its downtown Frisbie Station with high temperature superconducting cable. None of these, or similar installations constitute a first stage in a planned AC to DC conversion of bulk power transmission, but they do indicate that industry needs and advances in technology are converging on the use of high voltage DC to solve problems for which high voltage AC is no longer adequate. (It is conceivable that whenever the first long high voltage superconducting DC lin is installed, its additional capacity will provide a window of opportunity for conversion of parallel AC lines to DC.)

## Answers to Lester H. Fink

by John Zaborszky, Maria Ilic, and Ernst Scholtz

**Response of the author's:** The authors very much appreciate the contribution by the discussor of a historical sketch of development of transmission equipment technology (which was only alluded to in the paper) and explaining how it naturally led to the choice of AC because of the flexibility it provided at a point in time when the top level of hardware or equipment technology was the transformer and circuit breaker. This choice is valid even today on the subtransmission level and below in the overall electric power system (Fig. 2.1). At the time of decision of going AC all existing or expected interconnected power systems were small enough to not be overly concerned with the complexities of the dynamics and of processes of operating and controlling the entire interconnection systems. Generators inherently supply electric power over a (sinusoidal) carrier, i.e. in the AC format. Retaining this carrier based, or AC, format for the interconnected transmission system definitely provides flexibility to the transmission and distribution (load flow) system with the help of transformers and circuit breakers in choosing a variety of voltage levels.

However, as the the price paid for using AC, the sinusoidal AC carrier also generates a multitude of additional concepts such as active-reactive power, phasors, complex impedances, reactances, etc., concepts which exist only in the AC world and disappear when AC is not being used. And most of the gigantic structure of dynamic operation and control processes would also disappear.

Yet these concepts and their physical identities have been so deeply ingrained in our minds that most of us find it impossible to think of the electric power system in any other framework such as an All DC system.

Still, we should be aware of the fact that the above mentioned flexibility in matching voltages to amount of power and distance of transmission of an AC system is gained at a very high price of complexity of system dynamics and operation as compared to e.g. an All DC approach.

Developing such awareness of avoidable complexity in the dynamics of operation and control of the large power system is one objective of exploring in this paper these features provided by an All DC system.

At least partially, and not always consciously, such simplification was the motivating objective of two very important new developments in power electronics in recent decades "High temperature superconducting DC transmission and high voltage DC transmission utilizing power electronic devices" as described by the discussor at the end of the discussion. These are pointing toward a general development like ADC and its power electronic foundations.

One should mention here that in the paper a primitive

form of "series control" is utilized in Fig. 3.2, for purposes of exploration and explanation with assumption of the availability of suitable power electronic control. The discussion then provides data on an existing and operational specific example of such a device.

Beyond the material taken up in the discussion the paper proceeds exploring the utility of the ADC approach in at least three additional directions

### 1. Building block mosaic structure

A clear building block mosaic structure emerges with ADC and with the disappearance of the tightly coupled active and reactive power with the disappearance of the AC carrier. The system breaks down to a mosaic of only about 8 clearly defined Types of building blocks, which congeal into building block wise distributed control operation under the central command of the Control Centers as explained in connection with (Fig. 3.4).

### 2. Separation of Control Centers commanded and transient energy

When power is flowing at a constant rate through a building block which has energy storage capability like a transmission line (Type [1], or a turbo generator, Type [3]) then a fixed amount of energy (electromagnetic in Type [1] mechanical and electromagnetic in Type [3]) will be stored in the building block.

In operating or disturbed conditions the amount of power flow will vary either

- 1.) instantly as in switching operations, a sudden fault, (loss of equipment) or
- 2.) continuously, following normal changes of the load.

The change of energy is not simultaneous with the change of power e.g. after a sudden power flow change the energy (line current and charges in Type [1]) stays momentarily unchanged. So there will be a difference between the energy contents of the line and the energy needed to be stored in the line to match the new power flow as commanded by the Control Center.

When the change is gradual and continuous then the "transient energy" is usually computed periodically, say every  $\tau$  seconds.

If nothing is done this "transient energy" will result in system wide transient swings and eventually it is dissipated in the line resistances. These still would be of a simpler nature in ADC than what is happening in the AC case.

It should be realized and recognized that the AC carrier causes and generates a close coupling between active, and reactive power (which do not even exist without



using AC). This coupling in turn makes the dynamics and control of the large AC bulk transmission system with coast to coast connections very complicated (also challenging, and exciting as those of us building this colossal edifice of dynamics realize and appreciate).

Eliminating the AC carrier would eliminate most of this complexity and opens a new attractive alternative scenario which can be effective for ADC.

### 3. Draining off of transient size energy block by block for ADC

Since the various building blocks have their separate controls (if they are of the controlled type like transmission lines—Type [1]) which dominate over control effects from other building blocks. Furthermore control of the various building blocks actually aid each other moving the system toward the desired equilibrium solution established in the Control Center. In fact, given appropriate “shunt” controls in each block. it would be possible to drain off the excess, i.e. transient energy block by block as discussed in the paper (example in Appendix 2). This would then result in absence of transient dynamic oscillations (like those accompanying switching activities in common AC system) and result in a smooth sliding of the main stationary, equilibrium load flow through operation and disturbance caused changes, provided the draining process can operate very fast before the transients start.

Thus the shift of AC to ADC operation visualized in this exploration depends ultimately on the development of sophisticated power electronic hardware, some already accomplished as pointed out by the review. Similarly the block by block draining out of transient energy postulated here depends on very extensive Control Center and Communications operations as grossly sketched out in Block {C} in the functional block diagram Fig. 3.4 of the paper. It is doubtful that it could ever be accomplished in the All AC framework. On the other hand the current surge of computation speed may have already brought it into feasibility for ADC and the speedup still continues.

Thus this paper gives a global design for ADC not tied to existing practice and not restricted to one or two aspects.

Thus our paper explores the broad scope of technical potentials and problems of an All DC bulk power system but with little attention to its business aspects.

### 4. An interesting coincidence

It so happens that the business aspects of ADC transmission networks, without any deep technical scope are comprehensively discussed in a paper published concurrently (Sept. 15, 01) by James Liles in a business journal (Public Utilities Fortnightly).

The two papers supplement each other. In contrast to our broad technical exploration

1. Liles's paper reveals a very large scale, strong and real effort by the business world to build three extensive bulk power trading DC networks (grids) each covering a major segment of the US.
2. In the latter part of his paper the major concern seems to be the complications arising in private ownership (or part ownership) of individual transmission lines within these grids because of the congestion problems which are even now creating severe problems in the AC bulk transmission systems.

Let us make a few comments which would come from the exploration and technical discussions on our paper.

The new ADC system will be controlled by dominant controls separated building block by building block (of 8 Types, transmission lines being Type [1]) under the command of the Control Center. So the Control Center will assign among other things the exact amount of flow through each line which then is enforced by the local dominant control in each block of Type [1]. Thus the Control Center, within its function of generating commands (box {C} in Fig. 3.4), can send power around the network in any optimal fashion up to the total load carrying capacity of the network (i.e. up to whole system congestion). No more congestion spots in the ADC network. Business companies still can own all or a specific fraction of individual transmission lines (technically this amounts to a constraint in the Control Center program).

The companies then have the desired control of using part or all of their share of property of the line. They can also rent directly any capacity which they own but do not use momentarily. Five minute (or even faster) trading is no problem.

In addition the system proposed by us, would drain out transient energy assuring smooth shifting of loads across the network without dynamic swinging.

So the two work areas represented by the two papers may be ideal counterparts.

Work beyond exploration in our project is continuing by proper research analysis of its operation and dynamics.

# The Electric Power System as a Customer-Driven System Endowed with Self-Healing Capabilities *A Report on CIMEG's Activities*

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## Abstract

The Consortium for the Intelligent Management of the Electric Power Grid (CIMEG)<sup>1</sup> is developing a new theoretical approach to modeling the deregulated power grid as a customer-driven system. The approach is demonstrated through TELOS, an agent-based anticipatory system that is under development in the service areas of Exelon and TVA. When the grid is viewed through the temporal behavior of its customers several possibilities for defensive and ameliorative strategies become easy to implement in an efficient and reliable manner. Yet, new modeling, identification and prediction challenges emerge. We present recent contributions and give a status report on CIMEG's accomplishments and work in progress.

## Keywords

Utilities Deregulation, Power Systems, Forecasting, Neuro-fuzzy Systems, Intelligent Systems

## 1. Introduction

In 1997, the United States Information Administration (EIA) predicted major benefits for the US economy from the introduction of competition in the electric power industry. Motivated by the desire for lower electricity prices and the success of deregulation in other industries (railroads, trucking, natural gas production, telephone industry) competition was expected to lower average energy prices as much as 6 to 13 percent by the year 2000 [2]. Although these predictions have not materialized in most US regions (certainly not in California which is experiencing an energy crisis) the restructuring of the US power industry is generating economic pressures for the development of new innovative technologies changing the nature of the electric power infrastructure.

In the future, electric power systems are expected to be fully coupled with information networks resulting in what is often

referred to as the "Intergrid." The marriage of power and information is already commonplace in several US utilities using advanced energy tracking systems to monitor consumption patterns and affect price-induced elasticity in demand.

In the Intergrid, predictions of anticipated global supply and local demand may be taken into account in anticipatory decision strategies concerning whether and in what sequence small generators should be dispatched as well as whether and in what sequence demand-side management actions could take place.

The Consortium for the Intelligent Management of the Electric Power Grid (CIMEG) has been investigating new intelligent approaches for endowing the grid with fault-containment, and self-stabilization and self-healing capabilities [1]. CIMEG's main efforts focus on investigating and developing a customer-driven intelligent systems approach that promotes anticipatory or proactive management of the electric power infrastructure. New anticipatory strategies for dispatching small generating units and price-induced elasticity in demand have been shown (through simulation) to promote the reliability and self-healing capabilities of the electric power grid. Anticipatory strategies are sequences of control actions that modify current state on the basis of anticipated future states [5]. We have shown that such anticipatory strategies could be effective on subsets of the electric power grid, called Local Area Grids (LAGs).

In essence, LAGs are sets of customers with a mix of residential, commercial, and industrial consumption patterns and volatilities. The connectivity of the grid permits LAG properties to be functionally defined (in terms of the number and types of loads and/or small generators) and does not necessarily require that LAGs are geographically contiguous. From the point of view of stability and security a LAG is where most interesting phenomena on the grid appear (early enough for effective actions to be taken promoting not only local but also the global well being of the system). A typical aggregate load in a LAG is in the range of 100-300 MW. Although most optimization and protection functions take place within LAGs (based on the observation and prediction of intra-LAG phenomena), inter-LAG behaviors are also important. For example, during periods of stress to regional grids (or even the entire system), LAGs may coalesce or break up to form new

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LAGs. Local anticipatory controls to protect the grid crucially depend on our ability to model the temporal behavior of individual loads and/or classes of loads that have significant local impact.

In the following sections we present a brief status report on CIMEG's agent-based framework, certain advancements and work on TELOS, an internet-based intelligent tool for the protection and self-healing of the Intergrid.

## 2. Agent-based Framework

Intelligent agents are software entities that carry out a set of well-defined instructions from humans, other agents or programs. These entities have some degree of autonomy and the ability to move around a network to accomplish their defined tasks. They are also endowed with some knowledge or representation of the user's goals to help them achieve their tasks [4].

A system consisting of many such autonomous agents is referred to as a multi-agent system. Such multi-agent systems provide for a modular, extensible approach to problem solving. The agents in a multi-agent system are collections that can dynamically organize themselves into organizations. These agent organizations can be hierarchical, democratic or some other form depending on the task involved.

In the developed framework predictions of customer demand drive supply scheduling, stability and congestion analyses and protection functions. The following important steps are taken in regular time intervals (our short-term horizon is currently one hour but the methodology can be implemented in varying time scales ranging from a minute to an hour):

- A dedicated prediction agent at the customer site computes how the electric load will vary for the short-term horizon and makes a prediction. The granularity of the predictions are area and problem specific and the prediction agent is capable of learning (via neurofuzzy tools)
- The values obtained from all prediction agents (within each LAG) are then used to determine the changes in the power flow of the grid. Various control actions can be taken to minimize different variables of interest; namely economic factors, safety considerations, customer importance, etc.
- The control actions that are determined and scheduled are then analyzed to ensure that the grid will be stable and optimal within the near future (the short-term horizon).
- As potential problems in meeting demand maybe encountered, anticipatory strategies for dispatching local generation (or energy storage) and/or achieving price-induced elasticity in demand profiles may be used within a LAG.

The steps are repeated at a rate that is sufficient computationally and physically. The **TELOS** (Transmission-distribution Entities with Learning and On-line Self-healing) system developed by CIMEG is realizing these procedures. TELOS maybe useful as a stand-alone system or as a tool for ISOs, RTOs and bulk power centers. The overall idea is to have a semi-autonomous distributed computing system tackling these problems in parallel with the capability to maintain system operation should even a few of the computational elements fail.

In implementing the proposed framework a series of challenges emerge from the fact that the electric power grid is an extremely complex system. They include the following:

- The scale of the problem is at least the same, if not bigger than, what is found when one looks at the Internet alone (a system hosting millions of computers). Any solution to the complexity of the grid should be examined within this scope and should not just work for a small group of entities. Furthermore, since we're seeking the solution for the entire grid, the final answer should be both technically and economically feasible.
- Avoiding and containing cascading failures is a major concern for the deregulated power system. This means that a failure (either in power or in information) should be isolated and should not spread within the network.
- The solution should be scalable, which requires that it's open to the dynamical changes of the system: either in size or in structure. Considering the trend of deregulation, this requirement is mandatory.

The Intergrid calls for intelligent power meters having an IP address and local computing capability. Intelligent meters will further complicate the existing network, where huge amount of meters come into the scope of the problem. In order to meet the coming challenges, a feasible solution is expected to possess the following properties:

- Each agent should be relatively independent. It only exchanges necessary information with its environment. It is functionally self-contained which enables it to function with minimal interference from outside.
- Agents themselves should be passive. A passive agent will be disconnected from the network if it malfunctions. This also requires that each agent have some sort of self-diagnosis and self-healing capability. Whenever an internal, incurable error is detected, the agent isolates it from the others.
- Protocol-based robustness is preferable than implementation based robustness. By protocol-based robustness we means that any exception should be considered and handled explicitly by the protocol.

Examining the abovementioned requirements, we can conclude that only a distributed solution is able to meet all these challenges.

### 3. Customer-Based Grid Partitions

A LAG is defined as a set of customers within a service area. This is just a logical organization and need not necessarily reflect geographical proximity between the customers and producers. The central controlling agency in a LAG is called the LAG Manager. Each producer (small unit) or customer agent communicates important data to the LAG Manager, thus the LAG Manager has complete information about the status of the LAG at any given point of time. To incorporate fault-tolerance into the system, the producer/customer agents may communicate with a neighboring LAG Manager as well. The basic organization of a LAG is shown in figure 1 below.

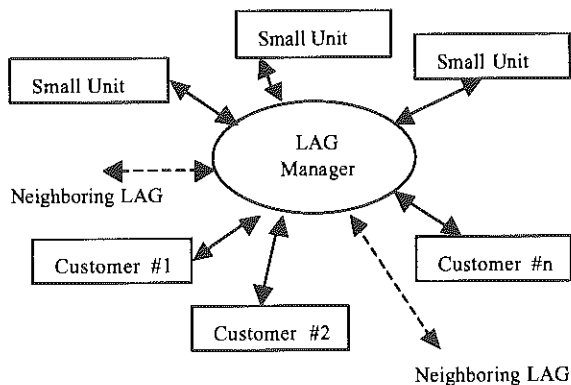


Figure 1: Organization of a LAG.

Each of the customer agents shown in the figure can represent either one large commercial/industrial customer or a group of small commercial or residential customers. Each of these customer agents will have a local database and prediction agents to perform load forecasts for that particular customer (or group of customers). Each customer agent can be represented as in figure 2 below.

The power meter logs power usage and feeds the data to the local database as well as to the prediction agents. The prediction agents use this current data as well as historical data from the database to make load forecasts for a specified time into the future. These forecasts are put back into the database and communicated to the LAG Manager along with the current load (as measured by the meter). The decision module then makes decisions based on the local forecasts and from the directives, if any, from the LAG Manager. The decisions are then conveyed to the effectors, which execute the final control action. This could be in the form of bringing online captive generation or shedding some local load.

The power meter logs power usage and feeds the data to the local database as well as to the prediction agents. The prediction agents use this current data as well as historical data from the database to make load forecasts for a specified time into the future. These forecasts are put back into the database and communicated to the LAG Manager along with the current load (as measured by the meter). The decision module then makes decisions based on the local forecasts and from the directives, if any, from the LAG Manager. The decisions are then conveyed to the effectors, which execute the final control action. This could be in the form of bringing online captive generation or shedding some local load.

The LAG Manager gets information about the current demand in the LAG, the amount of local generation available and inflows/outflows from neighboring LAGs. Also the LAG Manager has knowledge of all the contracts the customers have with respect to curtailment programs. Hence, with authorization from the power company, the LAG Manager can

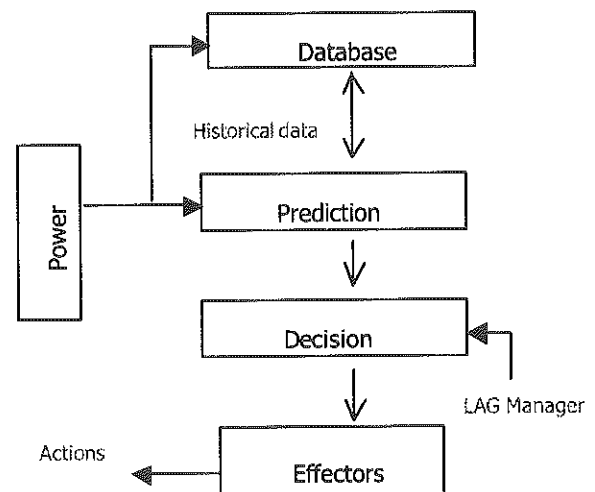


Figure 2: Customer agent at intelligent meter.

choose to curtail power for certain customers, if the situation demands such an action.

The LAGs themselves can be organized in a hierarchical manner, with entities at the top having a more abstract view of the system. Tasks like optimal power flow solutions and system wide security analysis can be handled at these higher levels.

### 4. TELOS Agents

The main goals for TELOS are guarding reliability and efficiency within a Local Area Grid (LAG) without compromising the reliability of neighboring LAGs and by extension the reliability of the grid. These goals are achievable through the balance of the power flow in a customer-driven model of the system. In order to maintain the balance, we need some sort of monitoring and controlling mechanism to watch the power flow through each segment of the grid. Generally, two kinds of control mechanisms exist for such purposes: centralized

control and distributed control. Centralized control is not very attractive for complex system modeling. First, it is rather impractical to consolidate all responsibilities to one central agent; it requires huge communication resources and network bandwidth. Second, a central control agent may create a severe performance bottleneck for the entire network. It is intuitively obvious that adding another layer of complexity on the grid (that is agents) is not simplifying or enhancing the reliability of the system. Therefore, a distributed architecture, where responsibilities are spread among a set of agents, offers a successful and reliable solution to a complex system. In a distributed system, each agent is assumed to have some degree of autonomy. There is no single powerful agent with responsibility for managing other agents. Thus, hardware and software requirement can be subsequently lowered (from the point of view of costs) and overall system reliability enhanced. Robustness is an inherent feature of distributed systems. Since the inference amongst different agents has been reduced a minimal level, the corruption of one or several agents may not cause a large-scale negative effect on the grid. An important question concerns the degree of autonomy of individual agent. Should each agent be fully autonomous and thus behaves independently? Alternatively, should there be some hierarchical control agents governing a small set of agents?

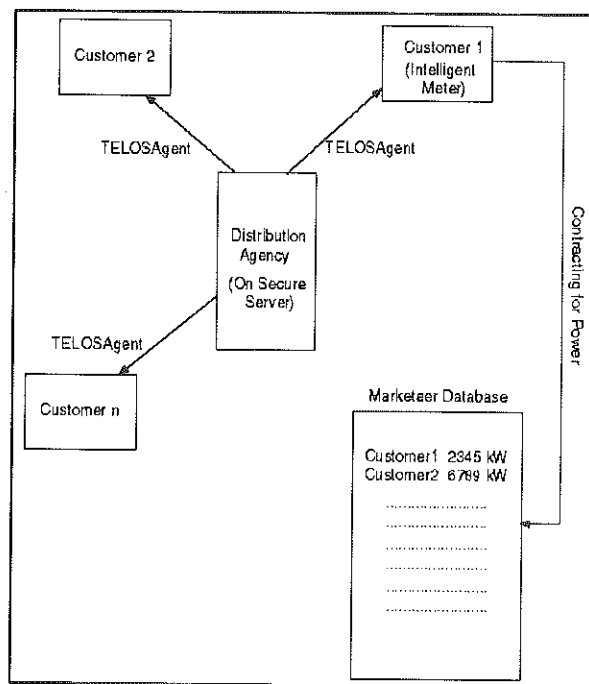


Figure 3: Customer agents in TELOS.

Figure 4 illustrates how some of TELOS' agents work. At some initial point in time a Distribution Agency sends agents, called TELOSAgents, to customer sites. Each agent sent resides on a host intelligent meter and gets trained with a specific customer's data. It subsequently predicts what the customer's demand will be in the short-term time horizon (e.g., during the next hour) and sends out this information to a Marketeer Database where available power and prices are listed. The information is also sent to the LAG Manager and

shared with authorized agents elsewhere (not shown in figure 3).

## 5. Load Forecasting

Neural networks and fuzzy logic have been studied and determined to be a robust forecasting system for non-stationary and non-linear time series applications [3][6]. Incorporating artificial neural network (ANN) and fuzzy logic technology, a novel neurofuzzy forecaster is developed as a part of our new power grid management. The new system is composed of two neural networks in series and a fuzzy analysis module in parallel. As shown in figure 4, the combined output serves as input to a third neural network, which is responsible for the final prediction (an extensive description of the algorithm can be found in Reference [7]).

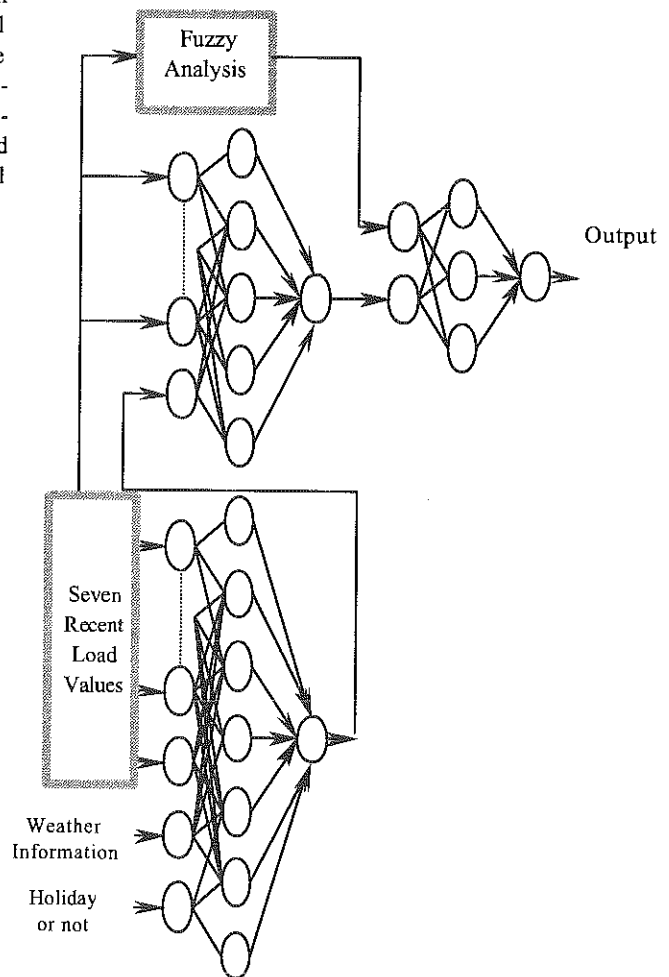


Figure 4: Combined neural network and fuzzy logic prediction system.

The first partially connected neural network performs 'steady-state' hourly load prediction. The input data includes current weather condition, the previous load, day of the week, time of the day and holidays or not. In order to improve the accuracy, the weather condition is fuzzified in advance. A provisional prediction is provided by this module and serves as input to the second neural network for correction.

The fuzzy analysis module identifies whether there is a significant deviation from a customer's equilibrium or steady-state pattern of power consumption – this is intended to capture quick changes in power consumption patterns such as those appearing on certain holidays or unexpected events. The previous load values are fed into this module. Several important features are extracted from the incoming on-line signal and fuzzified into triangular fuzzy numbers. These fuzzy numbers are then fused into one final fuzzy number in order to summarize all the information contained. A final decision of to which category (*increasing*, *decreasing* or *constant*) the current sample point belongs is provided based on the information included in the final fuzzy number.

The neural network on the upper right hand side of figure 4 is utilized to make modifications on the provisional prediction with the signal trend decision coming from the fuzzy module. The output of this network is the prediction of power that the customer will demand during the next time step, which is used by TELOS.

Validation tests have been performed on this new methodology with data provided by a local electric utility. The results show that the load prediction during holidays and specific events is satisfactory and the overall accuracy can be improved significantly. The overall error rate is less than 8%.

## 6. Summary

A new framework for the intelligent management of the electric power grid under the deregulated system has been presented in this paper. TELOS is a distributed agent-based system that realizes the proposed framework. In TELOS, the various entities in the electric power grid are represented as intelligent agents, each with a specified function. These agents are organized in a semi-hierarchical structure (actually a "federalist" type of structure) and work in collaboration with each other, except where privacy issues dictate otherwise.

Accurate nodal load forecasting at all times is an important issue in the effective management of the Intergrid via the presented framework. Novel neurofuzzy techniques have been developed for nodal demand prediction (at each customer site). These prediction tools are embedded into the customer agent. Given the estimated loads, the LAG decides on the most appropriate action to satisfy this demand. Power-flow solution is checked to see if any physical or operating constraints are violated. Fault detection and isolation proceeds on similar grounds. Because the whole strategy is a bottom-up one, i.e., the customer is the basis of the entire operation, the approach lends very well to the deregulated scenario.

CIMEG is investigating several topics that we did not present in this paper. They include the following: Genetic algorithms for optimal power flow calculations and the dispatch of small generators (pursued by J. Lawler and J. Ilic at the University of Tennessee, Knoxville); new metrics for model selection combining complexity theory and prediction errors (also pursued at the University of Tennessee by A. Gribok, A. Urmanov and R.E. Uhrig); intelligent tools for dispatching emerging

energy storage technologies; neural wavelet-based metrics for quantifying the predictability of each individual customer (as a function of time); novel complexity-based methodologies for dynamically segmenting the Intergrid into LAGs; computational metaphors of consciousness applied to the self-healing of the Intergrid (pursued at Fisk University by H.J. Caulfield and his colleagues); and self-healing algorithms based on simplified models of cellular metabolism and self-repair.

## Acknowledgement

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## Discussions on Session I: FUTURE-SYSTEMS & RELIABILITY

### Part 1

**Chairman** (Les Fink): By virtue of ruthlessly rushing each other's papers, we managed to arrive at the time for discussion and questions now. We have two re-conceptualizations of future power systems. John Zaborszky presented what we might think of as a re-conceptualization of the electromagnetic structure of the system to improve its controllability, and then we have a re-conceptualization of the control structure in terms of the anticipatory nature of the system control. Both of these are fascinating. I would ask firstly if anyone has questions or comments on the materials John Zaborszky has presented, so tersely in the time available to him. I'm hoping some of you have a chance to look at the text of the presentation on the Internet, so that they are not telling you completely cold.

**C. Canizares** (University of Waterloo): My question is for Professor Zaborszky. I guess, probably he has a chance to explain a little more about the control. I'm referring to a little bit of the problem, it was looked up by Bryan Johnson and Bob Lasseter. It was looking at the issue of DC Power Systems. I guess they are the superconductors to the transmission system. One of the problems they dealt with was control, coordination and protection. Could you elaborate on the way you see the control of the system? The issue here was the dynamics shifted from the generator side onto the transmission system, so the dynamic time scales changed from transients to electromagnetics. Please elaborate on the way you see the control, the coordinated control of the whole system.

**J. Zaborszky**: We actually utilize the great simplification of avoiding the AC dynamics, which when we change to DC, becomes really separable into building blocks. Typical building blocks would be seen as transmission line, bus, generating station and so on. Only eight of them will describe the whole system, and this building block is something, which has a very defined role like a transmission line, connected to the other part of the system. Since the interaction becomes much looser, everything can get simpler. For instance, the various control operations, because of the uniform simple nature of the building block, the control can be looked at from building blocks. Of course this command of control center and they give instructions to individual building blocks. There is a very overwhelming or dominant control action, which will force the building blocks to set each particular target. For instance, in the case of the transmission line, it will be the power flow of the transmission line, or, for the bus, it would be the voltage of the bus. This can be set by a direct and powerful local control device. All of these controls act to

achieve a stable desirable solution. I advise you to take a look at the collection of the slides, which I had over there. Each slide has a short explanation.

**F. Wu** (University of Hong Kong): I have a question for the first speaker as well. I guess I confine to the second speaker for the time being. The power industry is undergoing a transformation - the industry is open for competition. One scenario people talk about is the customer side competition and retail competition. It seems to me you assume there is an entity where ISO or system operator has all the information about the customers, the historical details of the customers. But if we go into retail competition, then the customer information becomes proprietary. In that scenario, how would you reconcile the conflict in control and in economics?

**L. Tsoukalas**: Very good point. Indeed, the consumption patterns are proprietary information. Imagine if I am a chocolate manufacturer and there is another chocolate manufacturer down the road and he knows my profile and a lot about my inventory and my business. There is a security aspect to this. That is, to isolate and to keep this record locked, to protect it from being seen by others. I mean the ISO doesn't really know the individual customer tasks. This information should be protected. The data doesn't transfer, or in any way shouldn't flow liberally in the information network. It should be locally held. There are points and times where it needs to flow, but this is extremely important. You pointed out this big issue.

**F. Wu**: When the power system was first developed, there was a battle between Thomas Edison and George Westinghouse. When Thomas Edison proposed the DC system, George Westinghouse proposed the AC system. We all know George Westinghouse won the battle finally. For the next hundred years the power system has developed into mostly AC systems. Who wants to change back to the DC system? Probably there are several dimensions to the issue. One is the technical issue and the other is economics. The third is the social issue. I guess John suggests that we start the discussion, revisit the issue from the technical point of view. So I will confine my comment on the technical issue of the DC system. AC systems were developed more than 100 years ago, we did not anticipate many of the problems. Because technology was not there at the time, so as the system develops, the system evolves. As the equipment became available, we realize other technical problems. That's how it develops all these years. My question to John is: in old DC systems, do you anticipate the devices

will become available? Do we anticipate there would be other major technical issues on the horizon?

**J. Zaborszky:** Of course the point which we make in the paper is that the choice was probably correct. The initial discussions, the level of terminology, and the solution was logical. When the system grew to gigantic proportions, then the theory and dynamic aspects become tremendously complicated. The question we are asking is, if we start the system today, what kind of function we would use, and what kind of advantages we would provide. Now the answer is that there are major advantages, and much simplification of the theory structure. You pointed out the issue of what is the price to pay. In our program we made some assumptions of further developments, because the technology of communication and control plays a major role in the real organization. So we did some exploration of the progress of the technology, but the progress is on going and very fast in that direction. So to that extent we have made some assumptions there, they are not going very far in the direction.

**Chairman:** That concludes the presentations of the program. I have an apology. In the first discussion period, I neglected to ask whether there are any prepared discussions. If any of you did have prepared discussions for either of those two papers, I hope you would have let me know. So then I would ask the four speakers if they would come up on the platform.



## BULK TRANSMISSION SYSTEM RELIABILITY PERFORMANCE STANDARDS FOR USE IN A DEREGULATED ELECTRICITY MARKET

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**Abstract:** - The reliability of an electric utility transmission system is a measure of its ability to continuously meet the demands of all its customers (i.e., points of delivery). Enhancing the supply reliability is one of planning and design targets of any utility within the constraints of capital investments, intense free market competition, variable and higher level of customer preferences and safety and environmental considerations. The utilization of transmission system facilities is changing from its traditional role in this new deregulated era and raising significant concerns about the possible erosion of the reliability of utility transmission facilities. It has been recognized that the movement towards a deregulated and competitive electricity market, decisions to improve reliability will be heavily influenced by customer preferences requiring service level benchmarks to be defined. This paper presents an approach to establish customer-responsive transmission system reliability performance standards that provide a measure against which the different planning and design procedures can be evaluated to assist in achieving the primary objective of providing reliable electricity with competitive rates to utility customers. The applications of the developed standards are illustrated using a simple system example.

**Key Words:** Competitive market, customer-responsive, reliability standards, point of delivery, value-based justification.

### INTRODUCTION

Modern society depends on uninterrupted electricity supply for sustainable development. Reliability of electricity supply, therefore, becomes a paramount element in a country's ability to organize its commerce and industry capabilities [1]. Today, industrial and commercial customers of an electric utility compete in the global market place. The customer's ability to compete in intense free market environment is influenced by the ability of its electricity suppliers to provide services that are of high reliability and cost – effective. Increasingly, a utility's every ultimate customer is going to look for an electricity service that balances cost, product support and

reliability in a manner that best satisfy the customer's individual requirements.

Customers who have processes that are highly susceptible to sustained interruptions in their power supply view reliability as a key factor in their ability to produce end products. The product output volume is the key component in the profitability of any commercial and industrial manufacturing organization. Electricity supply interruptions upset customers' manufacturing processes resulting in a decrease in product output and profitability.

As the deregulation and competition unfold in the electricity sector, the customers will increasingly look for value-added services from the utilities for their very survival in the global market place. One of the major challenges to electric utilities is to increase the market value of the services they provide with the right amount of reliability while providing lower rates for its customers [2]. It is, therefore, important that a utility develops a strategy that defines the cost, service and reliability standards it will provide to its customers in the new competitive era.

Virtually all Canadian utilities have been monitoring and reporting transmission system interruptions since late eighties. Lately, it has been recognized that with no reliability performance standards in place, it is not possible for a utility or its customers to measure when a performance issue exists. It also is virtually impossible to determine whether reliability performance driven system improvements are required without an effective point of utilization performance feedback loop between planning, operation and maintenance groups of a utility and its industrial and commercial customers.

This paper proposes an approach to develop customer-responsive bulk transmission system reliability standards based on historical bulk system reliability performance records which can represent an acceptable level of service that is an appropriate balance between the cost of facilities and the reliability of supply received by the majority of utility customers. The utility reliability performance standards provide industrial and commercial customers with a

knowledge base to assess the impact of unreliable utility supplies on their processes and profitability.

### RELIABILITY INDICES

All electric utilities in Canada collect and report transmission outage information using a consistent outage data collection format designed by the Canadian Electricity Association (CEA) [3]. It's a comprehensive data bank, which the CEA uses to produce annual reports on interruption statistics [4]. Several other utility groups also report reliability measurement processes based on bulk system point of utilization supply. References 5 and 6 discuss the similarities and differences as well as limitations in some of the measurement methods used in different measurement systems. The most developed system for collecting and analyzing the outage data is currently used by the CEA. The CEA data collection and reporting system is highly data intensive and provides useful indices on reliability performance of the transmission system.

A point of delivery is the point of supply where the energy from the transmission network is transferred to the distribution system or the retail customer. The point is generally taken as the transformer substation low voltage bus at a utility owned substation. For customer owned stations supplied directly from the high voltage networks, this point is generally taken as the interface between the utility owned equipment and the customer equipment. A point of delivery is considered to be interrupted when its voltage supply is interrupted due to a problem with the busbar or due to problems within the transmission system. It is important to note that point of delivery interruptions caused by problems originating either in the distribution system or the customer system are not considered, unless the transmission system fails to limit their impacts to other delivery points.

Performance indices referred to in this paper are a measure of supply continuity to a point of delivery including related issues of voltage, frequency and other power quality issues. In order to capture power quality and low voltage related load loss events, a utility would require a sophisticated and comprehensive measurement scheme in its system at all points of delivery. (e.g., SCADA, power line monitors, supervisory control computers, etc.). The cost of continuously monitoring momentary interruptions at all points of delivery is costly issue today for utilities. However, many large industrial and commercial facilities have some form of monitoring in place with their computerized utility metering services.

An interruption to a point of delivery is defined as being momentary when the duration of the interruption is less than one minute. These are interruptions of transient nature and are generally restored by automatic reclosing or auto-sectionalizing facilities. An interruption is defined as being sustained when the loss of supply voltage to a point of delivery of supply takes place longer than one minute.

Traditionally, the electric utility industry has been focused on minimizing sustained outages. Over the past decade, there has

been increasing attention to momentary outages due to the impact of these outage types on new susceptible computerized load equipment. In addition, the majority of transmission disturbances affecting customers are momentary (trip and reclose), or are a result of voltage violations and other power quality problems. It has been reported [e.g., References 7, 8 and 9] that for a significant percentage of customers process interruptions are due to power quality problems rather than sustained outages.

As a reflection of transmission system reliability performance, the electric utility industry has developed a number of average system-wide performance measures. These system averages provide an overall indication of system reliability performance. Traditionally, these indices are used for objective comparison between different operating areas and to ascertain historical evidence of increasing or decreasing trends in transmission system reliability performance over the years.

A few of the widely used reliability performance indices are defined in the following [5]:

#### 1. System Average Interruption Frequency Index (SAIFI)

##### a) Momentary Interruption Frequency Index SAIFI(MI)

$$\text{SAIFI(MI)} = \frac{\text{Total number of momentary interruptions}}{\text{Total number of points of delivery monitored}}$$

Units: momentary interruptions per point of delivery per year

SAIFI(MI) provides a measure of the average number of momentary interruptions that a point of delivery experiences during a year.

##### b) Sustained Interruption Frequency Index SAIFI(SI)

$$\text{SAIFI(SI)} = \frac{\text{Total number of sustained interruptions}}{\text{Total number of points of delivery monitored}}$$

Units: sustained interruptions per point of delivery per year.

SAIFI(SI) provides a measure of the average number of sustained interruptions that a point of delivery experiences during a year.

#### 2. System Average Interruption Duration Index (SAIDI)

$$\text{SAIDI} = \frac{\text{Total duration of all interruptions}}{\text{Total number of points of delivery monitored}}$$

Units: minutes per point of delivery per year.

SAIDI presents a measure of the average total interruption duration that a point of delivery experiences during a year.

#### 3. System Average Restoration Index (SARI)

$$\text{SARI} = \frac{\text{Total duration of all interruptions}}{\text{Total number of sustained interruptions}}$$

Units: minutes per interruption.

SARI provides a measure of the average interruption duration of a point of delivery. In fact, it represents the average restoration time for each point of delivery interruption.

#### 4. Delivery Point Unreliability Index (DPUI)

$$\text{DPUI} = \frac{\text{Total unsupplied energy in MW} \cdot \text{Min}}{\text{System peak load in MW}}$$

Units: System Minutes.

“One System Minute” is equivalent to an interruption of the total system load for one minute at the time of the annual system peak.

System-wide performance measures provide a good indication of the long-term average transmission system performance; however, these indices tend to mask unusually good or poor performance of individual points of delivery. Evaluation of the interruption frequency and annual interruption duration of individual point of delivery determines the average performance of points of utilization. Electric utilities may use some or all of the reliability indices depending on their own, customers’ and regulatory bodies’ requirements.

The performance indices may not include interruptions caused by major storms or other natural disasters of extensive loss of service such as the January 1998 ice storms in Eastern Canada covering parts of Ontario, Quebec and Maritime provinces. This is valid as the major disaster types could dramatically skew one-year’s statistics and the utility transmission systems are generally not designed to withstand these extreme weather conditions. Customers normally accept a service interruption when they perceive it to be due to a major storm or widespread severe disturbance that is felt to be beyond the utility control. Eventually, it is the electric utility that has to determine whether it is going to provide reliable and cost-effective service to customers. Moreover, increased competition will force utilities to use some form of reliability figures to present to existing and prospective customers for service evaluations.

This paper proposes an approach of taking a long-term average measured point of delivery performance and defining it as a service standard. The established standards would provide a measure against which the technical requirements for a system improvement project as well as different operating and maintenance practices could be evaluated. These numerical standards are based on past experience and generally perceived to be an acceptable level of service that is an appropriate balance between the cost of facilities and the reliability of supply received by the majority of utility customers. A possible itinerary for a single or set of transmission reliability standard levels is shown in Fig. 1.

With reference to Fig. 1, the annual reliability standards can follow various itineraries (e. g., year 1 - 2 - 3 - 4 - 5). The long-term average (i.e., 5 years) in this example remains near the minimum total reliability cost to both the utility and its customers. When the performance standard levels deviate significantly from the established norms or the long term performance trends are significantly eroding service performance, utilities can undertake economical mitigation actions to improve system reliability. Depending upon whether the frequency or duration norms are non-compliant will dictate what economical actions the utility can undertake to improve service reliability. In this new era of deregulation of the electric power industry, the difficulty for utilities is to formulate an action plan based on acceptable performance norms and define the maximum reliability standard levels to initiate economical mitigating actions.

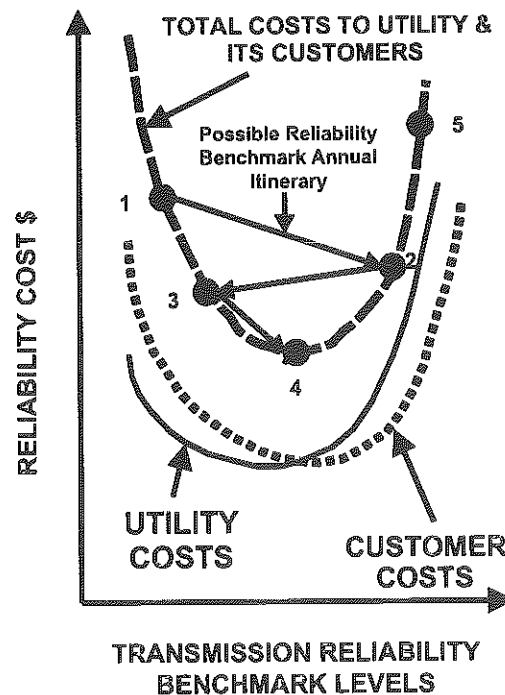


Fig. 1. Reliability cost versus transmission reliability standard levels

Changes in standard levels from year to year provide a guide for utilities to take proactive mitigating and reliability enforcement actions if the long-term average levels are outside acceptable norms. Severe storms can significantly erode standard levels; however, mitigating actions may be economically not feasible or impossible. Long-term averages excluding the impact of severe storm related events provide stable standards for utilities to determine trends in standards and make the appropriate economical decisions.

With reference to Fig. 1 it is important for utility and its customers to note that low reliability performance standard levels are costly to both the utility and its customers. However, reliability performance standard levels that are too high can also be costly to both the utility and its customers (e.g., costly for the utility to deliver and the incremental capital and operating costs could be reflected in higher consumer costs of energy). A reliability cost-reliability worth analysis is required to establish benchmark constraints in the form of upper and lower boundaries. Typical values of these standards are not readily available because of the present utility competitive market.

#### Performance Standards

Performance standards for transmission networks may be defined as the set of conditions that should be satisfied in order to achieve required reliability. These conditions are set in the form of numerical parameters that present quantitative measures of reliability, in other words, the upper bounds on unreliability.

Given the configuration of power networks, it is virtually impossible to provide the same level of service reliability to every customer. Customer expectations and the cost of service vary greatly depending on their geographical location in relationship to existing transmission services. Urban areas normally experience higher reliability levels due to the concentration of critical facilities, as urban life style is

highly dependent on a reliable supply of electricity. Within urban areas of high load density, transmission and distribution networks are highly integrated. In order to obtain high reliability levels, trade-off is made in providing the service reliability either through a distribution design or through a transmission design. Urban area transmission network design may include two transmission circuits per point of delivery, one transformer per point of delivery and a backup transformer if the load level reaches, say 25 MW, high side interrupting devices and split secondary bus with remote or automatic closing facilities.

On the contrary, service to rural areas normally associated with longer feeders and lower load densities. Long feeder circuits are often exposed to more lightning, animals, trees, vehicles and other hazards than urban feeders. Rural networks generally experience more interruptions per year. The duration of rural network interruptions is also significantly longer due to the lengthy times often required to isolate and identify faulty feeder sections spread over a large geographical area (e.g., 25-mile rural tap). Rural area networks usually consist of single radial transmission line, single transformer per point of delivery, no high side breaker and high side faulting switch with transmission line clearing at remote terminal. Many farm industries (e.g., poultry, dairy, layer barns, etc.) have standby generation equipment at their facilities to mitigate the impact of lengthy rural outages.

The basic objective of establishing reliability standards is to provide the different customer types with some assurance that reliability levels will not drop below a pre-determined level. Tables I and II present some typical system-wide performance standards for urban and rural transmission systems considering all points of delivery. These standards are based on the long-term electric industry average statistics [5]. These performance standards provide an overall indication of transmission system reliability, however, mask the individual point of delivery reliability performance in a particular year.

With reference to Tables I and II, the historical system performance standards (i.e., SAIFI (SI), SAIDI, SARI and DPUI) for the rural area are approximately double the urban system performance standards. In the majority of utility case studies, the capital requirements to improve the rural system reliability standard levels to the level of urban customers cannot be justified from a reliability cost-reliability worth analysis. However, it is important for rural industries to have knowledge of the range of rural power system performance standard levels, which can be incorporated into their daily operating practices of their respective processes.

TABLE I  
System-Wide long-term Reliability Performance  
STANDARDS  
SAIFI(MI), Saifi(SI) and SAIDI  
CONSIDERING ALL POINTS OF DELIVERY

| SAIFI (MI)<br>(interruptions per<br>delivery point per<br>year) |       | SAIFI (SI)<br>(interruptions<br>per delivery<br>point per year) |       | SAIDI<br>(minutes per<br>delivery point per<br>year) |       |
|-----------------------------------------------------------------|-------|-----------------------------------------------------------------|-------|------------------------------------------------------|-------|
| urban                                                           | rural | urban                                                           | rural | urban                                                | rural |
| 0.75                                                            | 2.0   | 0.60                                                            | 1.50  | 65                                                   | 120   |

TABLE II  
SYSTEM-WIDE LONG-TERM RELIABILITY PERFORMANCE  
STANDARDS  
SARI and DPUI  
CONSIDERING ALL POINTS OF DELIVERY

| SARI<br>( minutes per<br>interruption) |       | DPUI<br>(system minutes) |       |
|----------------------------------------|-------|--------------------------|-------|
| urban                                  | rural | urban                    | rural |
| 65                                     | 110   | 55                       | 100   |

Tables III and IV provide frequency, duration and annual outage duration standards for individual point of delivery for one operating year [5]. Both long-term and yearly performance standards are important when considering reliability performance driven system improvement projects. The individual point of delivery reliability standards provide customers with a knowledge base for comparing existing and future levels of service reliability.

TABLE III  
INDIVIDUAL POINT OF DELIVERY RELIABILITY  
PERFORMANCE STANDARDS  
MAXIMUM NUMBER OF MOMENTARY AND SUSTAINED  
INTERRUPTIONS IN ONE YEAR

| Maximum number of<br>momentary interruptions in<br>one year |       | Maximum number of<br>sustained interruptions in one<br>year |       |
|-------------------------------------------------------------|-------|-------------------------------------------------------------|-------|
| urban                                                       | rural | urban                                                       | rural |
| 4                                                           | 10    | 2                                                           | 4     |

TABLE IV  
INDIVIDUAL POINT OF DELIVERY RELIABILITY  
PERFORMANCE STANDARDS  
MAXIMUM OUTAGE DURATION AND MAXIMUM  
CUMULATIVE OUTAGE DURATION

| Maximum outage duration<br>per interruption, minutes<br>For one year |           | Maximum cumulative annual<br>outage time, minutes for one<br>year |       |
|----------------------------------------------------------------------|-----------|-------------------------------------------------------------------|-------|
| urban                                                                | rural     | urban                                                             | rural |
| 90                                                                   | 240 -1440 | 120                                                               | 1440  |

The maximum outage duration per interruption could be anywhere between a couple of hours to a day depending on the time requirements for a mobile substation to be connected to the site. Any major substation outages in the rural area (e.g., transformer failure) can result in lengthy interruptions to the rural community particularly during severe lengthy storms.

Tables I to IV provide an acceptable upper bounds on unreliability performance, which provide a cut-off point satisfying which normally would not require a review of individual point of delivery and / or overall system reliability performance. However, violations of these targets would warrant a rigorous review of poor point of delivery performance with respect to causes, and correlation to the equipment performance and different operations and maintenance policies.

## INCORPORATING VALE-BASED PLANNING CONCEPTS IN THE PLANNING STANDARDS

Reliability of electric service should be based on balancing the costs to a utility and the value of the benefits received by its customers. Therefore, in order to render a rational means of decision making on the necessity of changing service continuity levels experienced by customers, utility costs and the costs incurred by customers associated with interruptions of service must be incorporated in current planning and operating practices [10 - 15]. Value-based planning methods are appealing in that they attempt to mathematically compare the cost of unreliability with the cost of providing additional reliability in order to determine whether the system enhancements are justified.

A value-based reliability planning approach attempts to locate the minimum cost solution where total cost includes the utility investment cost plus the operating cost plus the customer interruption cost. Fig. 1 illustrates how utility costs (i.e., reflected in customer rates) and the customer interruption costs are combined to give the 'total cost'.

The utility cost curve shows how customer rates go up as more money is spent for increased system reliability levels. The customer interruption cost curve shows how customer cost of interruptions decreases as the system reliability increases. It is also important to note that for low levels of system reliability levels, the customer interruption costs are significant. The utility cost curve, however, can also increase significantly in the additional costs of restoring the system to a normal operating state and the loss of revenue (i.e., the utility cost curve shown in Figure 1 is based on the belief that increased costs will achieve higher levels of system reliability). When the combined utility and customer interruption costs are minimized, then the utility customers will receive the least cost service. Therefore, using the concept of value-based system reliability planning, a given level of service reliability can be examined in terms of the cost and the worth to the customer of providing the electric service from various proposed transmission configurations.

The value-based analysis can add great insight to the transmission system reinforcement problems and has sufficient merit on that basis alone. It would be extremely hard to justify building a project that one could not rationalize provided sufficient benefits to warrant the expected cost. Accordingly, it is important that all potential transmission system improvement projects identified using the reliability performance standards presented in Section III should be subjected to a value-based assessment before their materialization.

The basic objective of bulk transmission reliability planning is to determine and therefore plan the transmission system with a reliability that is suitable for the individual transmission system. This involves the recognition of reliability cost and reliability worth. A cost / benefit analysis to determine when

an additional transmission source should be planned is required to complement the reliability planning standards for transmission planning. The additional source should be provided if the analysis indicates that the improvement in supply reliability would be cost effective. Outage probability and outage cost data specific to the system being studied should be utilized for cost / benefit analysis. An illustrative example for the framework of cost-benefit analysis of transmission upgrade is given in following.

### *Evaluating the Cost - Benefit of Radial versus Loop Feed*

A very simplified representation of the investment decision is adopted in this example. The basic intent behind this is to focus on the framework for cost - benefit analysis in similar situations and the very essence of the trade - off involved. The example, for simplicity, assumed the alternative considered would provide perfect reliability. The cost figures used for the customer interruption and for the facility in the example are in Canadian funds. The economic parameters assumed are 2 per cent inflation rate and 9.71 per cent discount rate. An aggregate outage cost value of \$14/kWh was used in computing impact of customer interruptions.

For this example, assume that there is a radial transmission line that has a substation at the end of the line that supplies an area at 144 kV. Assume that annual measurements of point of delivery reliability performance for the radial substation reveal sub-standard reliability performance for the radial delivery point according to the reliability standards presented in Section III. Planning engineers would normally perform conventional technical and economic studies to investigate different transmission upgrade projects for the area network served by the radial substation. Let the least cost transmission project recommended by the planning engineers based on cost, technical superiority, long-term fit, flexibility, environment, safety and considering all other pros and cons is to provide another feed to the substation, eventually transforming the radial network into a meshed network in order to improve the service reliability to the area customers.

If implemented, the proposed alternate feed is expected to reduce the customer outage costs. The next step would be to perform a cost-benefit analysis for the proposed line addition to the area to ascertain whether the capital investment would be justified from customers' point of interest in terms of reduced customer interruption cost rendered by the facility addition. Table V describes steps to calculate the present value of reliability benefits, i.e., avoided customer interruption costs, should a dual feed be provided to a load point supplied by a single radial line at present.

TABLE V  
COST – BENEFIT OF A LOOP FEED  
TO A RADIAL LOAD

|                                                                                      |                                             |
|--------------------------------------------------------------------------------------|---------------------------------------------|
| Economic life of line                                                                | 30 years                                    |
| Length of line                                                                       | 100 km                                      |
| Average outage frequency                                                             | 0.2927 occurrences<br>per year<br>(100 km ) |
| Average length of an outage                                                          | 5.81 hours                                  |
| Expected outage hours<br>avoided                                                     | $0.2927 \times 5.81 = 1.7$<br>hours / year  |
| Unserved load                                                                        | 35 MW                                       |
| Load factor                                                                          | 85 percent                                  |
| Avoided expected unserved<br>energy (EUE)                                            | $35 \times 1.7 \times .85 = 50.6$<br>MWh    |
| Customer interruption cost                                                           | \$ 14 / kWh                                 |
| Expected reliability benefits                                                        | \$ 14,000 x 50.6 =<br>\$ 708,400 / year     |
| Expected cumulative present<br>value of reliability benefits<br>over 30 years        | \$ 8,948,000                                |
| Capital cost of 100 km line                                                          | \$ 10,000,000                               |
| Cumulative present value of<br>the cost of 100 km line over<br>30 year economic life | \$ 15,287,000                               |

The load is interrupted every time the line is out. Assume that such interruptions average 1.7 hours per year. The substation supplies a peak load of 35 MW and the annual load factor is 85 percent. Therefore, the average load not supplied is 29.8 MW. The expected unserved energy (EUE) is then 50.6 MWh per year which is the product of the average load not supplied and the average outage duration per year.

Using the aggregate value of the customer interruption cost of \$ 14 / kWh, the outage cost amounts to \$ 708,400 per year. The expected cumulative present value of the customer outage cost over 30 year is \$ 8,948,000.

An option to reduce the above outage costs is to add a second line to the substation, thereby virtually eliminating the annual outage time. The cumulative present value of the cost of adding a 100 km line at the cost of \$ 100,000 per kilometer line over 30 year economic life is \$ 15,287,000.

In this example, the investment cost exceeds the expected customer outage costs. The customers, therefore, would find it more cost-effective to incur the outages, because adding a second circuit would not result in least-cost service. However, if either the outage rate or the interruption cost were higher, outage costs would make addition of a new line cost effective. The value-based methodology is very sensitive to outage duration and outage cost data. It should also be noted that this analysis was based on the maximum load staying at 35 MW. If the load were to increase, then the economics to reinforce the area supply would be more favorable.

### Conclusions

Electricity is viewed as an essential service by the modern society and the general population expects that utility companies will plan and construct adequate facilities to guarantee a reasonable level of supply reliability. In addition to satisfying societal expectations, a minimum standard would present customers with an indicator that they could use in their business planning processes. This indicator is of paramount importance especially to those customers who have supply sensitive processes for it establishes a standard for the supply reliability variable in their different production processes.

This paper has presented an approach to establish transmission system reliability performance standards based on historical operating experience data that generally represented an acceptable level of service to customers. These standards have a number of applications and can be applied to developing reliability performance standards for industrial and commercial power systems.

The standards are primarily intended for use as an aid in making decisions for the optimal allocation of available resources in the transmission system planning and design. When the performance becomes worse than the benchmark level, alternatives for changing the system can be investigated. The benchmarks are intended to provide consistency in evaluating system reinforcement needs and effectiveness of operation and maintenance strategies.

The standards would render feedback to planners on the result of the executed projects and to operations and maintenance personnel on the reliability effects of operating and maintenance practices. The standards, however, should not be considered as rigid requirements as refinements to the standards may be required from time to time to reflect changing utility business environment and appropriate customer performance requirements.

In conclusion, it is important to note that the desired level of reliability for a point of delivery can be achieved by controlling exposure to interruptions, by controlling recovery from interruptions, and by controlling numbers and types of facilities and their configurations. The annual point of delivery reliability performance calibration against the standards would allow performing earlier mentioned control functions in a consistent manner.

These standards are vital to determining the changing utilization of transmission facilities in new era of deregulation. The question remaining to be answered is how much will the utility transmission facility's reliability levels be eroded and how far are the standards from the historical "traditional" norms.

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## New Approach for Risk Assessment in Probabilistic Reliability Calculation

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**Abstract**—Under the new conditions in liberalised electricity markets, the need for detailed reliability analysis with quantitative results is steadily increasing. For the assessment of risks, the knowledge of the probability distributions of the reliability indices is a prerequisite. Up to now, this requires the usage of Monte-Carlo-Simulations. The faster analytical calculation approaches cannot provide probability distributions. This paper presents a method to identify the probability distributions out of the results of the analytical calculation. The method is explained and several examples demonstrating its results are illustrated.

**Keywords**—Probabilistic reliability calculation, probability distribution of probabilistic reliability indices, risk assessment

### 1 Introduction

Ongoing liberalisation efforts in the electricity markets throughout the world are exposing utility companies in those markets to ever growing cost pressure in the newly competitive environment. As the electricity prices decrease significantly in most cases, this loss of income for the utility companies has to be met by corresponding reductions in investment cost as well as operating cost in generation, transmission and distribution. Resulting measures include operation of the networks at higher loads, shortened or even cancelled investments or reduced maintenance activities. All these measures in general are likely to have a negative effect on the supply reliability of the customers.

However, supply reliability is also evolving into a key factor in the competition within the new electricity market. For customers, quality of supply is, apart from the price, the most interesting characteristic of electrical energy – especially as the public attention is drawn to events like the tremendous storms in Europe in 1999/2000 [1] or the energy crisis in California [2]. And for the utility companies, quality of supply will be a key characteristic in benchmarking processes and the only reason to justify higher costs with consideration to special geographical or climatical conditions, and also the only reason to justify higher prices for customers.

These two important aspects of liberalisation of course are in contrast to each other in most cases – reducing costs will have negative effects on the quality of supply. It is a delicate question to find the acceptable balance between cost effectiveness and supply quality. In order to support decision processes, information as detailed as possible is required. Whereas this is no general problem for the financial aspects, the assessment of supply quality – which is usually divided into voltage quality and supply reliability, which will be in the further scope of this paper – is by far more difficult.

As a result, the interest in detailed and quantified reliability analysis is also growing. Especially the requirement for quantified information cannot be fulfilled satisfactorily by classical tools used for the determination of supply reliability in network planning, like e.g. the (n-1)-criterion [3]. This criterion can only provide the information whether a network variant violates its requirements or not.

An appropriate tool to meet these new requirements is the probabilistic reliability calculation [4]. Several studies and application examples have proven the usefulness of such tools [4, 5]. This method allows the calculation of reliability indices for the complete system and for individual customers. Using different calculation and analysis modules, a detailed investigation of supply reliability providing quantitative results is possible.

In a deregulated market, it is especially important to be able to quantify the risks involved in planning decisions. With regard to reliability aspects, the risk derives from the stochastic nature of the considered failure events. Because of the rareness of the calculated contingencies, the probabilistic reliability indices normally possess a very widespread distribution. So, the knowledge of these probability distributions is a prerequisite for any risk assessment.

Up to now, the probability distributions of reliability indices are determined using Monte-Carlo-Simulation approaches. Featuring some advantages in modelling capabilities, one disadvantage of Monte Carlo simulations is the computation time. In order to achieve trustworthy results, events have to be simulated many times. Equation (1) can be used to estimate the



required number of simulations [6]. With typical values for the parameters the required number of simulations is quite high, e.g.  $n = 500000$  for a confidence interval of 95 % (Gauss parameter  $z = 1.96$ ), a tolerated relative error of  $f = 0.1$  and a probability of the event under consideration of  $p = 0.001$ . For comparable accuracy, the computation time is far higher for Monte Carlo simulations than for analytical calculations.

$$n = \frac{z^2}{f^2} \frac{1-p}{p} \quad (1)$$

This paper presents a new method to identify the probability distributions of reliability indices, using the results of analytical calculations. With the analytical approach, not only the expected value of each reliability index is calculated, but also the variance can be determined. Using these results, any distribution function described by two parameters can be identified. So, the continuous distribution function for the reliability index can be obtained which is an approximation for the actual discrete distribution.

After a short description of probabilistic reliability calculation in general, the method to determine probability distribution functions for certain reliability indices is presented in detail. Finally, using real example networks of the HV and MV level, the application of reliability analysis including risk assessment according to the newly developed method is demonstrated.

For the implementation of the new method described later on and the investigations of the example networks presented in this paper the probabilistic reliability calculation tool ZUBER (*Zuverlässigkeitsberechnung* – reliability calculation) [7] is used.

## 2 Probabilistic Reliability Analysis

Probabilistic reliability calculation was developed since the 1980s [8, 9] and its ability to provide detailed and, above all, quantitative results steadily increases its usage under the new conditions of deregulation [10, 11]. The schematic sequence of a probabilistic reliability analysis is shown in Fig. 1.

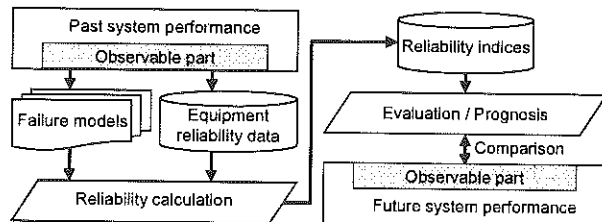


Fig. 1. Schematic sequence of a probabilistic reliability analysis

Observations of the past system performance provide several typical failure models, which allow a classification of the manifold fault occurrences and thus enable a mathematical description. Failure models include e.g. independent single

failures, common mode failures or expansion of the failure by malfunction of protection device. The appropriate equipment reliability data can also be derived from the past system performance. In Germany, the VDEW statistic of incidents in its extended form since 1994 [12] offers a large database from which trustworthy values for the required data can be derived. If available, statistical data of the system under consideration will provide valuable information. Together with standard topological and electrical data of the system, these reliability data make up the input data for the calculation module.

The actual reliability calculation uses either an analytical approach or a Monte-Carlo-Simulation to create the failure events. In the analytical approach, the contingency states are combinationally created and the frequency of occurrence is calculated for each contingency state from the input reliability data of the system components. Further investigations are performed only for those contingency states with a frequency of occurrence above a given limit. With the Monte-Carlo-Simulation, starting points in time for all events are determined at random and the course of events is time-sequentially simulated over the complete simulation period. In this approach, events occurring comparably often, like e.g. single failures of long lines, are calculated every time, whereas in the analytical approach, each contingency state is calculated only once. However, the modelling of time-sequential events, like e.g. usage of actual maintenance schedules, can be considered only using the Monte-Carlo-Simulation.

With both approaches, the generated contingencies are analysed for their effect on the network. In case of a supply interruption for any customer, also the restoration process is modelled, taking into consideration e.g. possible switching operations or load relocations with the respective durations, until complete re-supply of all loads. Relevant indices for each contingency state are stored in a database. Fig. 2. shows the flow chart of the calculation module.

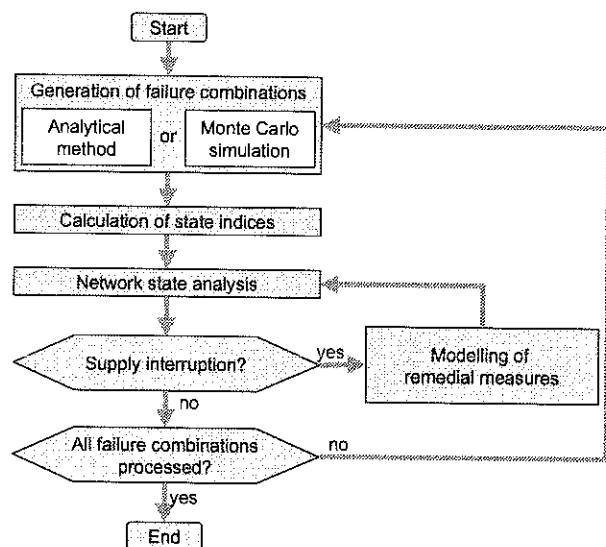


Fig. 2. Flow chart of probabilistic reliability calculation

Using this database, several different evaluations can be performed, e.g. the calculation of the reliability indices for each load node and the complete system, or a detailed list on the sequence of an individual contingency situation. Table I gives an overview of the customer related reliability indices calculated by the software.

Table I. Customer Related Reliability Indices

| Designation                                      | Symb. | Units       |
|--------------------------------------------------|-------|-------------|
| Frequency of supply interruptions                | $F_i$ | 1/a         |
| Av. duration of supply interruptions             | $T_i$ | h           |
| Probability of interruption, or non-availability | $Q_i$ | 1, or min/a |
| (Cumulative) interrupted power                   | $P_i$ | MVA/a       |
| (Cumulative) energy not supplied in time         | $E_i$ | MVAh/a      |

Other reliability indices, like e.g. system average interruption frequency index SAIFI, can be calculated from these basic indices [13]:

$$\text{SAIFI} = \frac{F_i}{N_{\text{Customers}}} \quad (2)$$

with:  $F_i$  frequency of interruptions in the system per year  
 $N_{\text{Customers}}$  Number of customers in the system

Under special – and scarce – circumstances, a comparison with the actual system performance is possible. Because of the rarity of the failure events, in general this will not be the case. It has to be noticed that the calculated probabilistic indices represent the expected values, which are calculated for an infinite time period. So, even observations lasting for several years cannot serve to determine the quality of a reliability calculation. This prognosis uncertainty usually represents – as long as suitable and secure input data are provided – the biggest part of the uncertainty of the results. The prognosis uncertainty is an intrinsic characteristic of the system, and not related to any approximations or errors in the calculation or in the input data.

Whereas the results of the analytical calculation method allow only the determination of the expected values and the variance of the reliability indices, usage of the Monte-Carlo-Simulation can additionally provide the actual probability distributions of the reliability indices. Any conclusions relating to reliability analysis should also consider that risk is included. As the risk implied in reliability assessment derives from the stochastic nature of the considered rare failure events, which is expressed by the probability distributions of the reliability indices, the knowledge of these distributions is the prerequisite for any related risk assessment.

One typical example for the application of probabilistic reliability analysis is the comparison of different network variants. For the comparison, preferably quantitative indices should be used in order to achieve detailed results. These can be provided using reliability calculation tools like ZUBER.

However, it is not sufficient to compare only the expected values of the indices. Due to the widespread distributions of the reliability indices, even very significant differences in the expected values may have only a low probability of occurrence. The probability of occurrence for a difference between two variants of at least  $\Delta x$  in the expected values of a reliability index  $x$  can be calculated using equation (3) [9]:

$$p(x_2 \geq x_1 + \Delta x) = 1 - \int_0^{x_1 + \Delta x} f_1(x) \cdot F_2(x + \Delta x) dx \quad (3.1)$$

$$F_2(x + \Delta x) = \int_0^{x + \Delta x} f_2(x) dx \quad (3.2)$$

with:  $f_1(x)$  probability density function of reliability index  $x$  for variant 1  
 $F_2(x)$  probability function of reliability index  $x$  for variant 2

### 3 Identification of Probability Distributions for Reliability Indices Using the Analytical Approach

#### 3.1 Introduction

In the following, a method to identify the probability distribution functions of probabilistic reliability indices by using the results of the analytical approach is presented. The method is based on the fact that some characteristics of the resulting probability distribution functions of the reliability indices are known, as they are the consequence of intrinsic properties of the system under consideration and its mathematical description.

#### 3.2 Frequency of supply interruptions

In probabilistic reliability calculation, it is usually assumed that the failure rate  $\lambda$  and the repair rate  $\mu$  of the system components – which are modelled with an up-state and a down-state – are constant in time.

$$\lambda = 1/\text{MTTF} ; \text{MTTF: mean time to failure} \quad (4)$$

$$\mu = 1/\text{MTTR} ; \text{MTTR: mean time to repair} \quad (5)$$

Using this modelling, the probability of the failure frequency of a system component is described by a Poisson distribution [14]. The discrete Poisson distribution gives the probability  $p_x(t)$  for the occurrence of  $x$  events in the interval  $(0, t)$ :

$$p_x(t) = \frac{(E(x))^x e^{-E(x)}}{x!} \quad (6)$$

with the expected value of the Poisson distribution:

$$E(x) = \lambda t \quad (7)$$

It can be seen from equation (6) that the Poisson distribution is characterised by only one parameter, which is the expected value. As the reliability index "frequency of supply interruptions" is the summarised value of the relevant component failures leading to supply interruptions, and as its expected value is of course calculated also in the analytical approach, the appropriate probability distribution can easily be identified. Chapter 4 will give examples for the identification of the probability distribution for the frequency of supply interruptions.

### 3.3 Average duration of supply interruptions

For the average duration of supply interruptions, the analytical calculation provides the expected value and the variance. However, an identification of the resulting probability distribution is not easily possible because of the constituents that influence the average duration of supply interruptions.

The first constituent are the stochastic failure events. A certain duration for the failure state is given in the equipment reliability data for each system component with regard to each failure model under consideration. This duration of the component failure state, which is known from the statistics, usually is not equivalent to the actual time to repair of the component, as the relevant system function is usually restored by provisional measures or substitution before the failure affected component is repaired completely – if not already by switching operations, as described in the following paragraph.

The problem arises from the second constituent that influences the average duration of supply interruptions: in most cases, supply to interrupted customers is not only restored after the termination of (provisional) repair measures, but through switching operations in the network. First, the failure affected component is identified and separated from the network. Subsequently, suitable switching operations are performed that allow re-supply of the interrupted customers.

The influence of such switching operations on the average duration may be very significant. Fig. 3 shows the probability density distribution of the average duration of supply interruptions for a section of a typical MV network operated using open loops (compare 4.1).

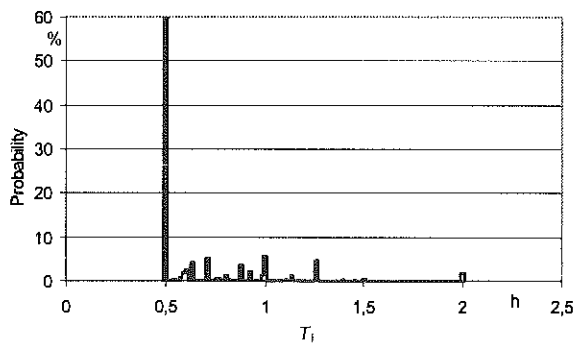


Fig. 3. Probability distribution of  $T_i$

For the modelling of the restoration process, it was assumed that the mean time for the identification and separation of failure affected components is 0.5 h and the mean duration of failure states for independent single outages 2 h for bus bars and 4 h for cables, respectively. It is obvious that the time for identification and separation of failure affected components has a very significant effect on the probability distribution – 60 % of the supply interruptions for customers are terminated by this measure. The duration of failure states of cables (4 h; not shown in Fig. 3) has a probability of almost zero, as the supply interruptions are terminated by other switching operations in less time. In contrary, the duration of failure states for bus bars (2 h) can be identified in the diagram, as in case of bus bar failures switching operations cannot restore supply to the customers connected to this bus bar.

The resulting shape of the probability density distribution, of which Fig. 3 is an example, cannot be described by commonly used probability distribution functions. However, the usage of the average duration of supply interruptions is not common in risk assessment of supply reliability.

### 3.4 Non-availability, interrupted power and energy not supplied in time

For the remaining reliability indices specified in Table I – non-availability, interrupted power and energy not supplied in time – it can be assumed that the respective probability distributions can be approximated using Weibull distributions. One main advantage of the Weibull distribution is that it has no specific characteristic shape [14]. Therefore, it can be used to represent many different distributions depending on the choice of the Weibull parameters. The probability density function  $f(x)$  and the probability distribution function  $F(x)$  of the Weibull distribution are given in equations (8) and (9):

$$f(x) = \frac{b}{a} \left( \frac{x}{a} \right)^{b-1} e^{-\left(\frac{x}{a}\right)^b} \quad (8)$$

$$F(x) = 1 - e^{-\left(\frac{x}{a}\right)^b} \quad (9)$$

It is important to note that the Weibull distribution is described by only two parameters  $a$  and  $b$ , despite its wide variety of shapes. As the analytical approach also provides two parameters for each reliability index – expected value and variance – the identification of the Weibull distribution is possible. The correlation between the Weibull parameters  $a$ ,  $b$  and the expected value  $E(x)$  and variance  $\sigma^2(x)$  of the distribution is given in equations (10) and (11):

$$E(x) = a \Gamma\left(1 + \frac{1}{b}\right) \quad (10)$$

$$\sigma^2(x) = a^2 \left[ \Gamma\left(1 + \frac{2}{b}\right) - \Gamma^2\left(1 + \frac{1}{b}\right) \right] \quad (11)$$

$\Gamma(x)$  is the Gamma function defined as follows:

$$\Gamma(x) = \int_0^{\infty} e^{-u} u^{x-1} du \quad (12)$$

With the given values for the expected value and variance of a reliability index, the corresponding Weibull parameters can be determined. As a direct calculation of the values of the Gamma function is not easily possible, an estimation method is used to specify the Weibull parameters.

Thus, the approximated probability distribution of the reliability index can be identified. Various examples for the determination of the probability distributions of the reliability indices non-availability, interrupted power and energy not supplied in time are presented in chapter 4.

## 4 Application Examples

### 4.1 MV network

The first example is a part of a real urban 10 kV cable network. The network is operated mainly using open loop structures. Fig. 4 shows a schematic plan of the MV example network. The network consists of 71 load nodes with a total load of 52 MVA, and the total circuit length is 28 km. Failure models considered in the analysis of the MV example network are independent single failure, malfunction of protection device, unnecessary protection operation with multiple outage and multiple earth faults with multiple outage. Descriptions of the outage models are included in e.g. [7, 12]. The respective equipment reliability data are taken from the literature [15, 16].

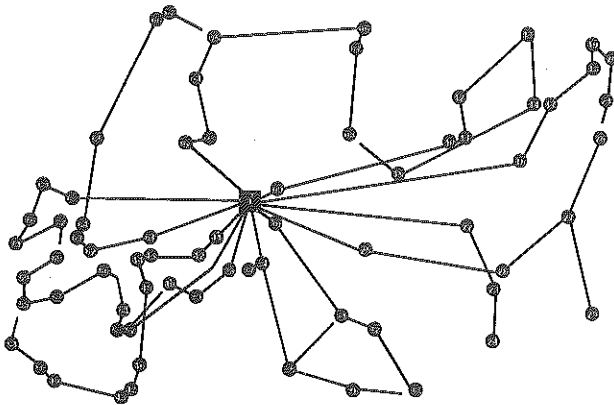


Fig. 4. Schematic plan of MV example network

For the example network, the reliability indices are calculated using the analytical approach. With the results for the expected value  $E(x)$  and the relative variance  $\sigma_r(x)$  – see equation (13) – for each reliability index, the parameter(s) of the Poisson- or Weibull distribution, respectively, are determined.

$$\sigma_r(x) = \frac{\sqrt{\sigma^2(x)}}{E(x)} \quad (13)$$

The results of the reliability calculation for the complete MV example network are listed in Table II and for station 06 only in Table III.

Table II. Reliability indices for the MV example network

| Reliability Index              | $E(x)$      | $\sigma_r(x)$ |
|--------------------------------|-------------|---------------|
| Frequency of supply interrupt. | 1.01 1/a    | 0.9950        |
| Probability of interruption    | 61.23 min/a | 1.3892        |
| Interrupted power              | 3.77 MVA/a  | 1.6746        |
| Energy not supplied in time    | 3.16 MVAh/a | 2.6782        |

Table III. Reliability indices for station 06 of the MV ex. netw.

| Reliability Index              | $E(x)$      | $\sigma_r(x)$ |
|--------------------------------|-------------|---------------|
| Frequency of supply interrupt. | 0.12 1/a    | 2.9158        |
| Probability of interruption    | 4.39 min/a  | 3.8106        |
| Interrupted power              | 0.04 MVA/a  | 3.0195        |
| Energy not supplied in time    | 0.02 MVAh/a | 4.0403        |

In order to be able to validate the approximated probability distributions, also a Monte-Carlo-Simulation is performed and the actual probability distributions of the reliability indices are specified.

The results of the approximations using either the Poisson- or the Weibull distributions in comparison to the actual probability distributions of the reliability indices are represented in the following figures. In the figures for the probability of interruption, interrupted power and energy not supplied in time – which are approximated using Weibull distributions – also the specified values for the Weibull parameters  $a$  and  $b$  are given in the figure captions. The Poisson distribution used with the frequency of supply interruptions is characterised by the expected value only.

For the MV example, first the result for the frequency of supply interruptions and the probability of interruption of the complete MV example network are shown in Fig. 5 and Fig. 6.

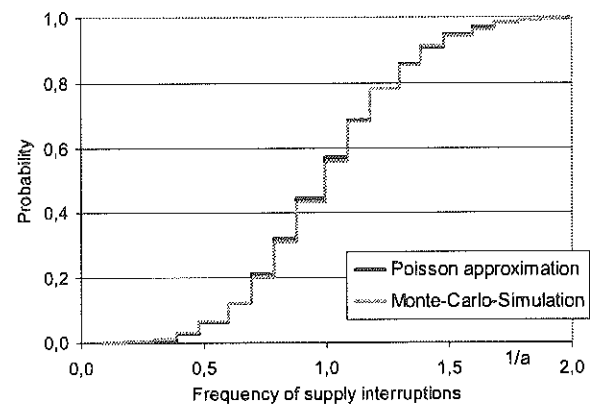


Fig. 5. Probability distribution function for frequency of supply interruptions of the MV example network

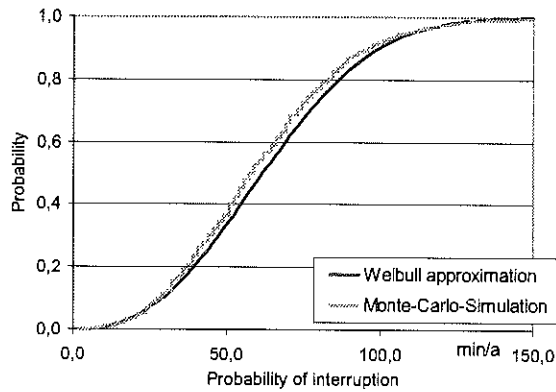


Fig. 6. Probability distribution function for probability of interruption of the MV example network ;  $a = 71.220$  ;  $b = 2.515$

The results for the interrupted power and the energy not supplied in time are given for station 06 of the MV example network in Fig. 7 and Fig. 8.

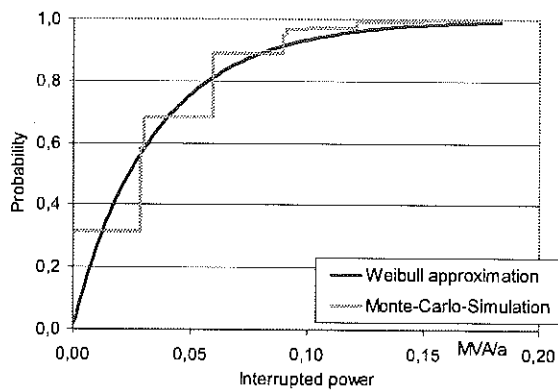


Fig. 7. Probability distribution function for interrupted power of station 06 of the MV example network ;  $a = 0.035$  ;  $b = 0.955$

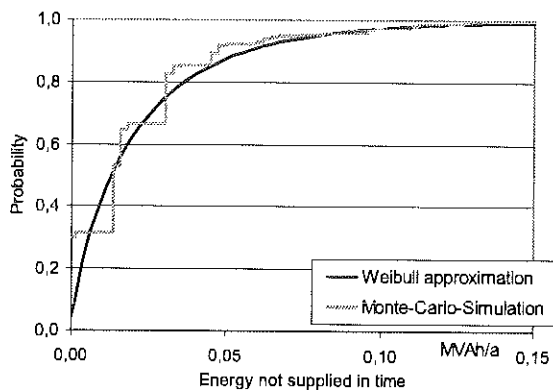


Fig. 8. Probability distribution function for energy not supplied in time of station 06 of the MV example network ;  $a = 0.020$  ;  $b = 0.805$

Finally, an example for the above described risk assessment method is presented for the MV example network. In this investigation, only one complete loop of the network is considered (stations 02 to 15, disconnected between 08 and 15). In the basic variant, the maximum line utilisation in this loop is 50 % for peak load in normal operation state. In a variant with increased line utilisation, this value is increased to 90 %. In this variant, the expected value of the energy not supplied in time rises to 113 % of the value of the basic variant, which can be considered as a significant increase. Using equation (3), the probability for a certain difference in the value of the energy not supplied between the two variants can be calculated. The results are shown in Fig. 9 for both the results with usage of the actual distributions provided by the Monte-Carlo-Simulation and also for the results using the approximated Weibull distributions. It can be seen that this probability for a higher energy not supplied in time in the variant with increased line utilisation is only slightly higher than 50 %. More detailed results of this investigation are included in [11].

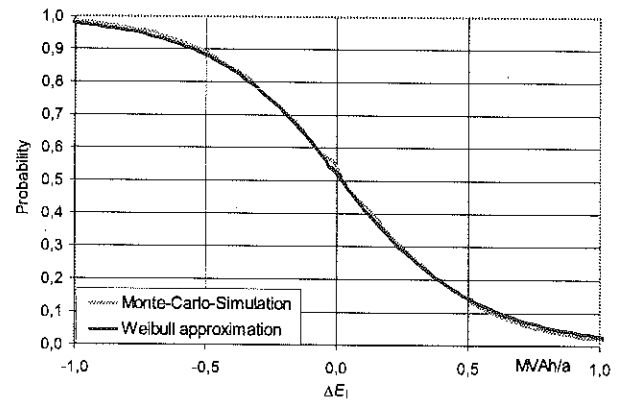


Fig. 9. Probability of a difference in energy not supplied in time between basic variant and variant with increased line utilisation for a section of the MV example network

#### 4.2 HV network

The second example is a part of a real 110 kV sub-transmission network. The network is supplied by two power plants and two incoming network feeders, one of which is normally in reserve state. Total circuit length is 263 km and number of bus bars is 16. The total load is 357 MVA. Fig. 10 shows a schematic plan of the HV example network. The failure models considered in the analysis of the HV example network are independent single failure, common mode failures of overhead lines, malfunction of protection device, unnecessary protection operation with multiple outage and multiple earth faults with multiple outage. Descriptions of the outage models are included in e.g. [7, 12]. The variance of the individual outage duration for each failure model is set to 100 % uniformly. The respective equipment reliability data are taken from the literature [9, 17].

The results of the reliability calculation for the complete HV example network are listed in Table IV and for station SS117-A only in Table V.

Also for the HV example network, a Monte-Carlo-Simulation is performed and the actual probability distributions of the reliability indices are specified in order to be able to validate the approximated probability distributions.

Table IV. Reliability indices for the HV example network

| Reliability Index             | $E(x)$       | $\sigma_r(x)$ |
|-------------------------------|--------------|---------------|
| Frequency of supply interrup. | 0.37 1/a     | 1.6332        |
| Probability of interruption   | 40.99 min/a  | 3.0410        |
| Interrupted power             | 20.50 MVA/a  | 1.9398        |
| Energy not supplied in time   | 26.05 MVAh/a | 8.3009        |

Table V. Reliability indices for station SS117-A of the HV example network

| Reliability Index              | $E(x)$      | $\sigma_r(x)$ |
|--------------------------------|-------------|---------------|
| Frequency of supply interrupt. | 0.14 1/a    | 2.6274        |
| Probability of interruption    | 10.74 min/a | 5.9354        |
| Interrupted power              | 6.18 MVA/a  | 2.6805        |
| Energy not supplied in time    | 7.64 MVAh/a | 6.0633        |

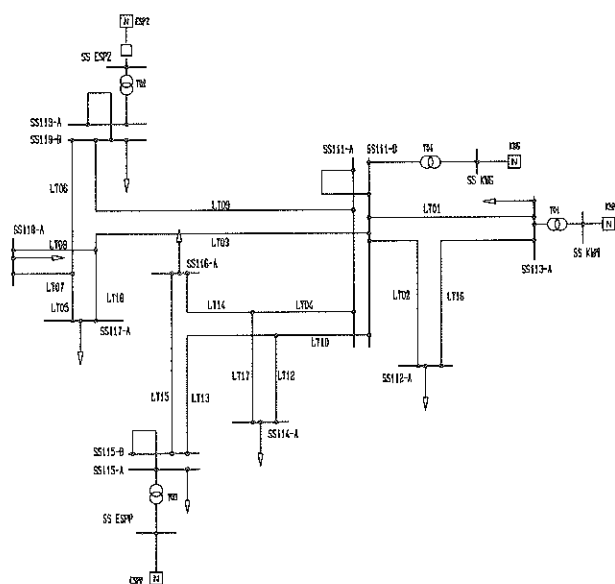


Fig. 10. Schematic plan of HV example network

For the HV example, first the result for the frequency of supply interruptions and the probability of interruption of station SS117-A of the HV example network are shown in Fig. 11 and Fig. 12.

The results for the interrupted power and the energy not supplied in time are given for the complete HV example network in Fig. 13 and Fig. 14.

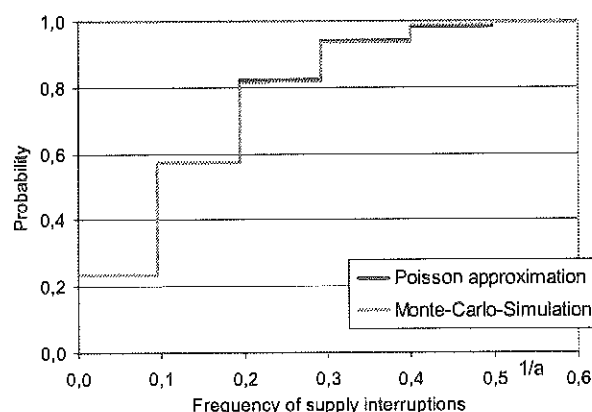


Fig. 11. Probability distribution function for frequency of supply interruptions of station SS117-A of the HV example network

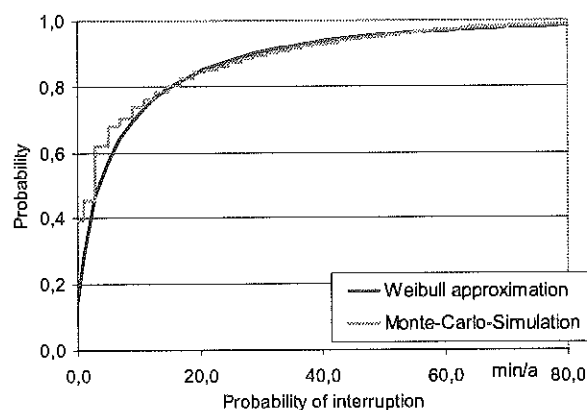


Fig. 12. Probability distribution function for probability of interruption of station SS117-A of the HV example network;  $a = 6.660$ ;  $b = 0.570$

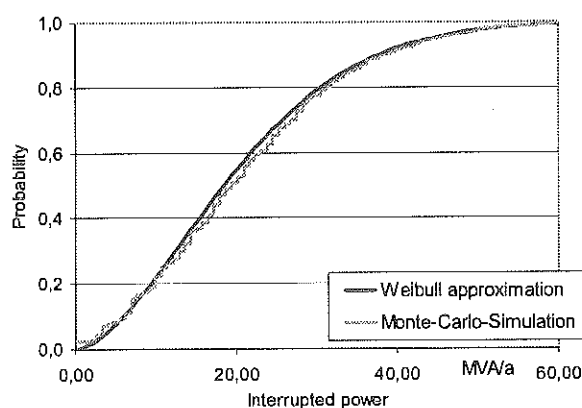


Fig. 13. Probability distribution function for interrupted power of the HV example network;  $a = 22.940$ ;  $b = 1.675$

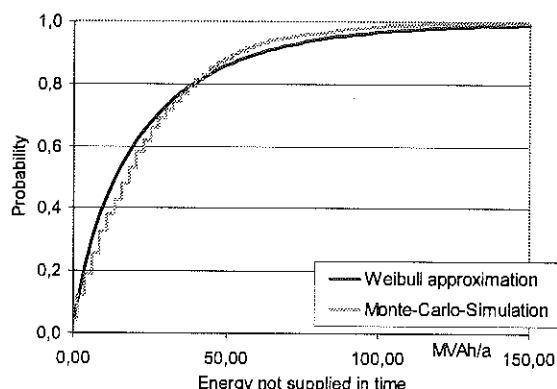


Fig. 14. Probability distribution function for energy not supplied in time of the HV example network;  $a = 21.500$ ;  $b = 0.800$

## 5 Conclusion

The method presented in this paper allows the identification of the probability distributions of probabilistic reliability indices using the results provided by the analytical calculation approach. The method is based on the fact that the probability distribution of the frequency of supply interruptions can be matched with high accuracy with a Poisson distribution, while the probability distributions for the probability of interruption, for the interrupted power and for the energy not supplied in time can be matched with good accuracy with Weibull distributions. These distributions are characterised by only one (Poisson distribution), respective two parameters (Weibull distribution). Thus, using the expected value and the variance for each reliability index, an identification of the probability distribution function is possible.

Extensive investigations show that the approximated distribution functions match the actual results of the Monte-Carlo-Simulation very well. Several examples for both a MV and a HV example network are presented in the paper. Also, the usage of risk assessment methods based on the probability distributions of the reliability indices is possible.

While the capabilities concerning the modelling of time-sequential events remain an advantage of the Monte-Carlo-Simulation, the determination of probability distributions – which is the basis for extensive reliability analysis taking risk into consideration – now is also possible using the analytical approach.

Further developments of this new approach may include the identification of the probability distribution of the average duration of supply interruptions and, above all, of the reimbursements as defined in the insurance model [18, 19].

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## Power Delivery Reliability among Multiple Players after Limited Deregulation

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This paper discusses power delivery reliability among multiple players. Even in the limited deregulation, multiple transactions are coexisted in the same power network. Due to the increase of the players, the reliability assessment would be changed from the classical one. Following issues are discussed in this paper. 1) Evaluation of power delivery reliability of the contract pairs among multiple players. 2) Power delivery reliability in the perfect regulation and in the perfect market. 3) RMR (reliability must-run) generations for the reliability improvement and for settlement of the network congestion. 4) The price signal of network congestion to improve the power delivery reliability.

### Limited Deregulation in Japan

Japanese government officially proposed the limited deregulation policy on May 1999 and carried it into effect on April 2000. The first point of Japanese rule is that, all future thermal plants will be constructed by competitive bidding among generation companies by long term based contract. Remaining nuclear & hydro plants, about 40% of total generation, will be constructed and operated by IOU under the regulated manner as existing way. The second point is that, about 30% of total demand, which are classified as the special HV consumers (over 20kV & 2MW), can make the transactions with generation companies freely through the bilateral contract. IOU supplies the remaining network consumers of about 70% of total demand and offers multiple menus such as TOU, DSM or other preferable tariff systems for network consumers. The third point is that, the operation and control sector will be separated by the information barrier or by the functionally unbundling manner from other sectors in each vertically bundled utility.

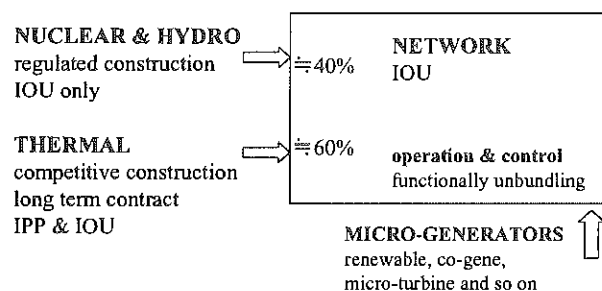


Figure 1. Plant construction under the limited competition

In 2003, the rule will be amended through the survey of the three-years-experiences under the limited deregulation. Concerning power delivery reliability, the collaboration work has been carried out among the government regulators, the

engineering experts and the economy experts. Compared with the other network industries, the features of power electricity commodity are characterized by the following issues.

- Requirement for the real time matching of the supply and demand balance.
- Broad area cascading effects of incidents through power network in emergency state.
- Difficulty in treatments of 'electricity resources' and in control of power flow in the power network.
- Long lead-time for constructing new facilities, and severe limitation for the right of way and the site of facilities.

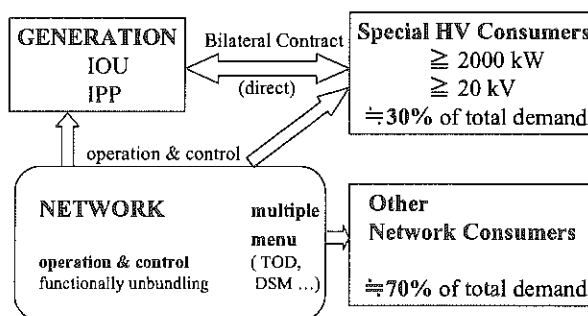


Figure 2. Power Transactions under the limited deregulation

### Power Delivery Reliability among Multiple Players

In the vertically integrated power systems, the reliability has been assessed by "adequacy" and "security" indexes. The adequacy is the capability to meet the energy demand within component rating and voltage limits. The security is the ability to withstand disturbances arising within that system without uncontrolled loss of load. In usual cases, the uncertainty of power system, such as forecasting errors of demand changes and forced outage occurrences of facilities, is assessed by the probabilistic method.

The deregulation of power industries induces the partitioning of various players, such as generation, transmission providers, service providers and customers themselves. Due to the increase of the players, the reliability assessment has to be changed from the classical approach and should be evaluated by the fulfillment of the contractual obligations and by considering game structure among players in electric power markets.

For the numerous players involved in the open access power systems, the network security is not their primary concern. On the other hand, the presence of power exchange market increases the transaction among players in number. Multiple players want to make operation or schedule decision through



non-discriminating environment

Performance indices of the power system are also greatly changed after the deregulation of power industries. In the vertically integrated power system, the primary target of overall utility has been the minimization of costs or expenditures under the constraints of permissible loss of load. After deregulation, the target of players moves toward the maximization of benefit by power transactions with the sense of non-cooperative game. In order to operate and schedule the power system safely, we need the non-profit third party action for coordination. Coalition or group of players will be included for assessing the reliability in the planning stage of power system facilities, where the cooperative game concept becomes important.

At first, we would like to discuss the power system modeling including power transactions characterized by the bilateral contract.  $G_k$  and  $D_k$  denote the generation power and the demand power of the contract pair  $\#k$ , respectively. If there is no assist from other contract pairs in the energy imbalance of the contract pair  $\#k$ ,  $EENS_k$  (expected energy not supplied) and  $EES_k$  (expected energy supplied) are calculated by the following equations with the network constraints.

$$EENS_k = E(D_k - G_k | G_k < D_k \text{ for contract pair } \#k) \quad (1)$$

$$EES_k = E(D_k) - EENS_k \quad (2)$$

$E(*)$  means the expected value of (\*). If the contract pair  $\#k$  can purchase the excess generation from another contract pair  $\#j$  with the premium price (the backup contract), the following amount of  $EENS_k$  would be supplied from the pair  $\#j$  in the energy imbalance of the pair  $\#k$ .

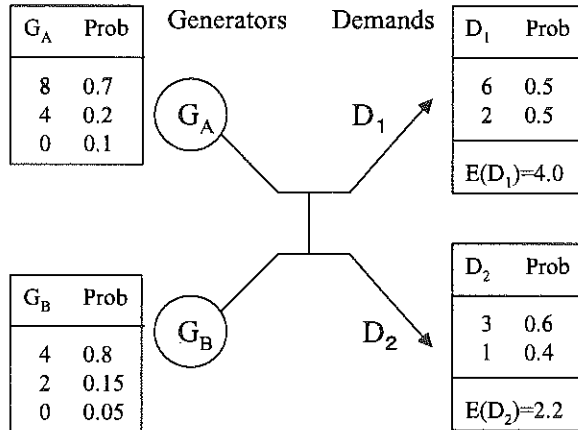


Figure 3. Two generators and two customers models

$$\Delta EENS_{k \leftarrow j} = E(P_{recovery\#k} | (P_{excess\#j} > 0) \cap (P_{deficiency\#k} > 0)) \quad (3)$$

$$\text{where } P_{recovery\#k} = [P_{excess\#j} | P_{excess\#j} \leq P_{deficiency\#k}] \\ \cup [P_{deficiency\#k} | P_{excess\#j} > P_{deficiency\#k}]$$

$EES$  and  $EENS$  are demonstrated by using the two generators

and two customers model as shown in Figure 3. Probabilistic characteristics of generators and demands are denoted in the same figure. As the generation or the demand power is given by discrete value,  $EES$  and  $EENS$  can be easily calculated by the combinatorial way. For the economical comparison in the electric power market, two types of the contract pair are tested. In type (1), the contract pair  $\#1$  and  $\#2$  are  $[G_A, D_1]$  and  $[G_B, D_2]$ , respectively. Similarly, the contract pair  $\#1$  and  $\#2$  in type (2) are  $[G_B, D_1]$  and  $[G_A, D_2]$ , respectively. Calculated  $EES$  and  $EENS$  are summarized in Table 1.

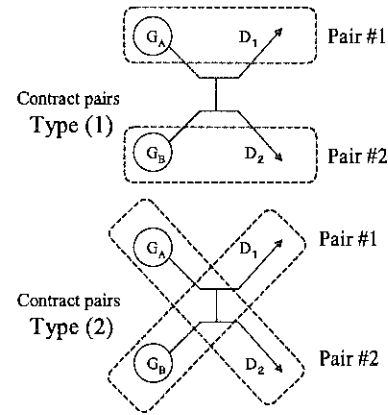


Figure 4. Types of contract pair

Table 1. Comparison of  $EES$  &  $EENS$  for different pairs

| Contract pair                                                              |      | Without help from another contract |      | With help from another pair<br>[Improved <i>EENS</i> ] |                          | Whole System <sup>^</sup> |
|----------------------------------------------------------------------------|------|------------------------------------|------|--------------------------------------------------------|--------------------------|---------------------------|
| Type                                                                       | Pair | pair <sup>*</sup>                  |      | $\Delta EENS_i$                                        | $EENS_i - \Delta EENS_i$ | $EENS$                    |
| Type1:                                                                     |      |                                    |      |                                                        |                          |                           |
| $\begin{bmatrix} G_A \rightarrow D_1 \\ G_B \rightarrow D_2 \end{bmatrix}$ |      | 3.4                                | 0.6  | 0.252                                                  | 0.348                    | 0.4015                    |
|                                                                            |      | 2.0                                | 0.2  | 0.1465                                                 | 0.0535                   |                           |
| Type2:                                                                     |      |                                    |      |                                                        |                          |                           |
| $\begin{bmatrix} G_B \rightarrow D_1 \\ G_A \rightarrow D_2 \end{bmatrix}$ |      | 2.7                                | 1.3  | 1.0545                                                 | 0.2455                   | 0.4015                    |
|                                                                            |      | 1.98                               | 0.22 | 0.064                                                  | 0.1560                   |                           |

For illustrating the power delivery reliability  $EENS_k$ , the preferable strategy of each player is surveyed with respect to the premium price of the backup contract. Let the unit price of generation power be given by  $P_A$  and  $P_B$  and the premium price factor for balancing operation be given by  $F_{premium}$  ( $F_{premium} > 1$ ). In the case of type (1) contract pairs, the customer payment for unit power is evaluated by the following equations. Similar equations can be introduced for the case of type (2) contract pairs.

$$E(P_{D1}) = \frac{EES_1 \times P_A + F_{premium} \times \Delta EENS_{1 \leftarrow 2} \times P_B}{EES_1 + \Delta EENS_{1 \leftarrow 2}} \quad (4)$$

$$E(P_{D2}) = \frac{EES_2 \times P_B + F_{premium} \times \Delta EENS_{2 \leftarrow 1} \times P_A}{EES_2 + \Delta EENS_{2 \leftarrow 1}} \quad (5)$$

$$EENS_{market} = \sum_{pair\#k}^{total} E(D_k - G_k | G_k < D_k, network\_constraints) \quad (7)$$
$$EENS_{\lim \text{ tied}} = \sum_{\text{pair } k} \lim_{\text{tied}} E(D_k - G_k | G_k < D_k, \text{network\_constraints})$$

$$EENS_{\text{market}} \geq EENS_{\lim \text{ tied}} \geq EENS_{\text{whole}}$$

□ DC tie line

August 3 days peak average, 2000

57.8 GW

25.4 GW

30.1 GW

15.4 GW

10.8 GW

5.2 GW

4.6 GW

13.9 GW

2.8 GW

1.2 GW

2.7 GW

1.4 GW

2.5 GW

1.1 GW

0.3 GW

0.6 GW

5.0 GW

0.6 GW

0.3 GW

5.4 GW

The generation company might construct its plant at the

unexpected site. Because of economic motivation, if the generation company wants to sell the electricity to the customer whose location is outside of region, the tie line would be the bottleneck of its transaction. However, the enhancement of the tie line capacity is not easy because of the limitation of the short circuit capacity.

#### Severe load following capacity

In Tokyo EPCo., the load change in the morning time (7-9 a.m.) is 20 GW/2hours (average) and >500MW/min. (maximum). The cooperation of whole thermal plants as a must-regulated generation has to be executed in this time period, because about 40% of nuclear generation is in the governor-locked operation (the constant power operation, no contribution for the load pickup operation).

#### Expectation to RMR generation

- Settlement of the bottleneck or the congestion the power network.
- Enhancement of the load following ability.
- Support as a var regulation generation.
- On-site generation in the emergency state.

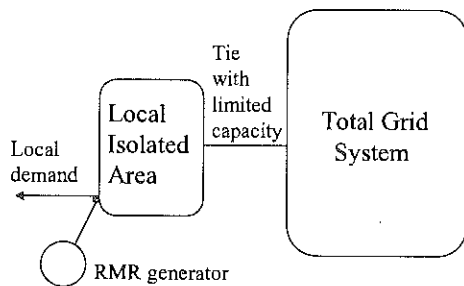


Figure 7. Concept of RMR generation

### Reliability based Expansion Program

#### Adequacy based expansion by the market signal

In the power market, the price spike occurs when the generation is not enough to supply the required power for customer. The price spike can be considered as the  $VoLL$  (Value of Lost Load). In Figure 8,  $G$  denotes the generation power available at a specific period.  $EENS$  is evaluated by the shadow area on the Figure. Let  $T_o$  be the operation period, then  $T_o \cdot EENS$  means the shedding energy which cannot be supplied through the deficiency of electricity. The increment of  $G$  introduces the decrement of  $EENS$ , then

$$T_o \cdot LoLP = -T_o \cdot \frac{d}{dG} EENS \quad (8)$$

, where  $LoLP$  means the loss of load probability as well known as a classic assessment of reliability. Fixed cost  $C_{fx}$  of critical generation, which can be constructed for avoiding the curtailment, is given by

$$LoLP \cdot T_o \cdot VoLL = C_{fx} \quad (9)$$

If  $VoLL$  or the price spike is large, the expensive peak plant can introduce in the power system. Similarly, if  $C_{fx}$  is lower, we can reduce the chance of curtailment.

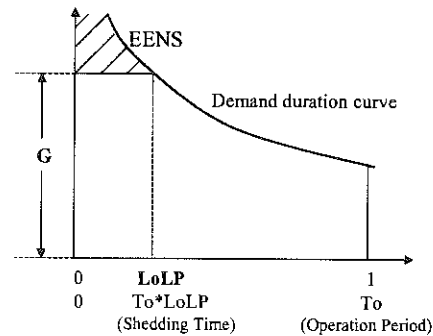


Figure 8. Demand duration curve,  $LoLP$  and  $EENS$

#### Reflection of the network congestion

The expansion based on the market signal is basically the adequacy based planning and are not able to consider the network congestion. In order to introduce the RMR generation idea and the network congestion into the expansion program, new concept like LBMP (location based marginal price, adopted in NYISO) will be needed. Combination of the market signal and the technical constraints is now studying. Typical constraints are the complicated power flow including multiple transactions among multiple players. Some experts lay claim to use only the market signal for operating and planning the deregulated power system, however, we think the technical requirements and the constraints are carefully involved in the competition process.

### Concluding Remarks and References

This paper discusses the limited deregulation in Japan, the power delivery reliability among multiple players, the perfect regulation and the perfect market of electricity, the RMR generation for enhancing the security based reliability and the reliability based expansion program.

The operation and planning using the market signal are the challenging topics, but we have to study carefully the topics in order to sustain the power system soundly.

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# A Hybrid Genetic Algorithm/SLP for Voltage Stability Constrained VAR Planning Problem

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**Abstracts:** A two level hybrid genetic algorithm (GA)/SLP method is presented to solve the multi transition states voltage stability constrained VAR planning problem, which is formulated as mixed integer nonlinear programming problem. In the first level, the GA is employed to select the candidate sites and VAR amount of the FACT devices to be installed in the system. These candidate allocations are passed to normal and contingency states in the second level, where the SLP is used to solve the nonlinear operation problems associated with every state. The objective function is to minimize the sum of installation costs and operating costs under normal and contingency states, which include costs of load shedding, other emergency controls, and the expected voltage collapse cost. Two version of the GA algorithms “ simple genetic algorithm and modified genetic algorithm” are implemented to show the feasibility of the proposed method. The proposed method has been applied on the AEP-14 bus system as well as IEEE-57 bus system to demonstrate its effectiveness.

**Keywords:** VAR planning, Voltage Stability, Genetic algorithms

## 1. INTRODUCTION

The objective of the VAR planning problem is to provide a minimum number of new reactive supplies to guarantee feasible operation in normal and post-contingency states. In general, this problem can be formulated as a mixed-integer nonlinear (MINL) programming problem. Various optimization techniques have been applied in the past to solve this problem. More specifically, the Generalized Bender Decomposition (GBD) technique was used to decompose the problem into a continuous sub-problem and integer sub-problem [1-2]. However, it is noted that, this technique does not always perform well due to the non-convexity of the problem and can leads to divergence problem or even get stuck at a local optimum rather than at a global optimum.

Recently, in order to circumvent this problem, some new

methods based on artificial intelligence have been applied. Hsiao et.al [3-4] applied the simulated annealing method to the VAR planning problem, which can theoretically converges to global optimum solution with probability one. However, it takes too much time to obtain a final solution. In order to retain the strength of approaches that search for the global solutions with a relatively fast speed, hybrid algorithms based on simulated annealing and genetic algorithms have presented in [5-8].

Unfortunately, the common feature of the above-mentioned studies is that the system security margin required to guard against voltage collapse is not considered. Recently, due to the necessity of the voltage stability margin, a few researches have been addressing the formulation of the VAR problem considering voltage stability problem [9-10], that can provide a more realistic solution for the VAR planning problem. However, the obtained solutions are sometimes too expensive to satisfy all the specified feasibility and stability constraints.

Therefore, the authors have introduced a new formulation for VAR planning problem considering voltage stability margin [11]. Different from the existing formulation, the method takes into account all possible transition states after contingency, where the load power margins are explicitly treated in this formulation to calculate the expected cost for voltage collapse as a function of loading margin. The objective function is to minimize the sum of installation costs and operating costs under normal and contingency states, which include costs of load shedding, other emergency controls, and the expected voltage collapse cost. The problem is formulated as MINL programming problem and GBD technique is applied to show the feasibility and solvability of this new formulation. However, the computational experience indicated that changing the system parameters might cause non-convexity of the problem and then leads to divergence for some cases.

In this paper extending the result of [11] a hybrid genetic

algorithm based on successive linear programming (SLP) is presented to avoid the divergence problem. That is, a two level hybrid genetic algorithm/SLP method is proposed to solve the multi transition states problem. In the first level, the GA is employed to select the candidate sites and VAR amount of the FACT devices to be installed in the system. Then, these candidate allocations are passed to all transition states under investigation in the second level, where the SLP is used to solve the nonlinear optimization problems. The output results of the second level are then passed to the first level where the fitness of each candidate solution is evaluated to produce the new generation. These iterative procedures are repeated till the termination criterion is satisfied. The numerical study has shown that the proposed method is numerically robust and yields better solutions compared with the GBD method.

## 2. PROBLEM FORMULATION

A new formulation [11] for voltage stability VAR planning problem is described in this section. The objective function is to minimize the sum of the installation costs and operating costs associated with every system transition state. The transition states may be simplified as shown in Fig.1, where three states A, B and C represents the base case, just after contingency and corrective control states respectively. The operating costs associated with state A include production or power losses costs and expected voltage collapse cost through state A. The operating costs associated with state B include expected voltage collapse cost through state B. The operating costs associated with state C include expected corrective control costs and expected voltage collapse cost through state C. the overall objective function is represented by the following equation:

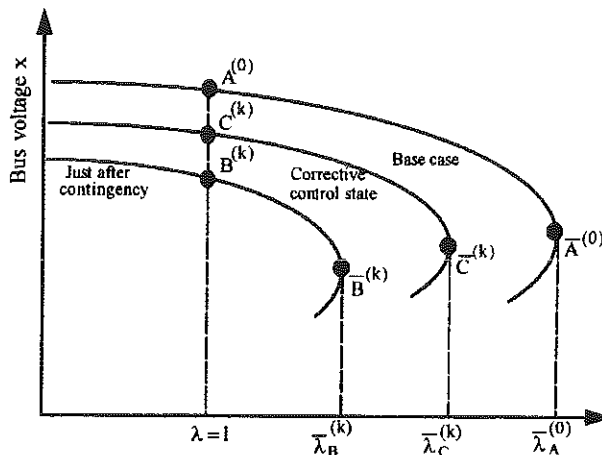


Fig.2 Nose curve

$$F = F_{It} + F_A + \sum_{k=1}^m (F_B^{(k)} + F_C^{(k)}) \quad (1)$$

where

$$F_A = F_{EC} + \omega(\bar{\lambda}_A)F_{BD}$$

$$F_B = \alpha^{(k)}\beta^{(k)}(\bar{\lambda}_B)F_{BD}$$

$$F_C = \alpha^{(k)}(1 - \beta^{(k)}(\bar{\lambda}_B))(F_{CC} + \gamma^{(k)}(\bar{\lambda}_C)F_{BD})$$

$F_{It}$  : investment cost

$F_A$  : base case operating cost

$F_B$  : just after contingency cost

$F_C$  : corrective state cost for the contingency k

$F_{BD}$  : breakdown cost

$m$  : number of contingencies

$F_{EC}$  : production or power losses costs

$F_{CC}$  : corrective control cost

$\bar{\lambda}_A, \bar{\lambda}_B, \bar{\lambda}_C$  : load parameter value for each state respectively

$\alpha^{(k)}$  : probability of contingency k

$\omega, \beta, \gamma$  : breakdown probabilities through state A, B and C respectively

### 2.1 Assumption

Although the exact computation of the breakdown probabilities  $\beta$ ,  $\omega$  and  $\gamma$  would include complicated procedure taking into account various probabilistic factors as well as dynamic factors, these factors are avoided in this paper to concentrate on more essential problems. That is, simply it is assumed that each breakdown probability is a function of the loading margin only, ( $\lambda_{mgn} = \bar{\lambda} - 1$ ) as shown in Fig.2a, where the margin is given by “ $\lambda - 1$ ” using loading parameter  $\lambda$  for each state as shown in Fig.1. This assumption implies that voltage collapse will occur at the nose point with probability 0.5, the larger the margin, the smaller the probability and vice versa.

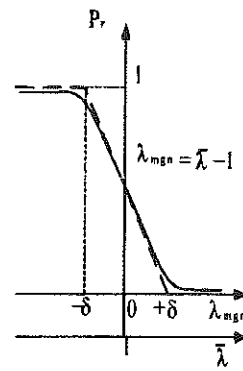


Fig.2a Probability of voltage collapse

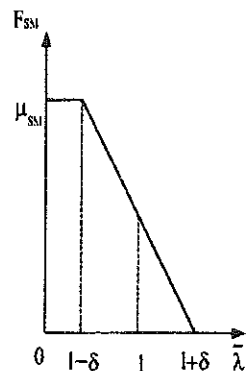


Fig.3b load margin cost

Thus, probabilities  $\omega$ ,  $\beta$  and  $\gamma$  are treated as the function of

$\bar{\lambda}_A$ ,  $\bar{\lambda}_B$ , and  $\bar{\lambda}_C$ , respectively, which become unity when the operating points are at the nose point. According to the probability curve, the expected voltage collapse cost from each state is represented in the same way as described in Fig.2b. This cost will be referred to as load margin cost hereafter in this paper, which is defined for each state as follows

$$F_{SM}(\bar{\lambda}) = P_i(\bar{\lambda}) F_{BD} \quad (2)$$

Additionally, the problem is restricted to the quick response FACTS devices. By so doing, the transitions of power system states of Fig. 1 may be simplified. Namely, as soon as a contingency occurs, the system state directly changes from A to C very quickly in conditions that the other emergency controls also respond fast enough. In the proceeding part of the paper, we assume such a situation where states B and C are identical. This case can be treated by setting  $\beta = 0$  in (1) only, which eliminates  $F_B$  as well as state B, simplifying the total objective function to the following equation:

$$\text{minimize } F = F_{it} + F_A + \sum_{k=1}^m F_C^{(k)} \quad (3)$$

A detailed description of every individual objective function stated in (3) and its associated constraints are presented in the following.

## 2.2 Investment Cost and Constraints

The total investment cost is expressed as:

$$F_{it}(c_{it}) = \sum_{i \in \Omega} (\mu_{fi} + \mu_{vi} c_{it}) d_i \quad (4)$$

Where  $\mu_{fi}$  and  $\mu_{vi}$  are the fixed cost and variable cost for candidate FACTS device  $i$  respectively;  $d_i = 1$  if the site  $i$  is selected for FACTS device expansion, otherwise  $d_i = 0$ ;  $\Omega$  is a set of all candidate sites and  $c_{it}$  is the size of the additional VAR of the device  $i$ . According to the physical considerations, the additional VAR of the selected FACTS devices is restricted to maximum limit  $c_{it_{max}}$ . These constraints can be stated as:

$$0 \leq c_{it} \leq c_{it_{max}} \quad \text{for each } i \in \Omega \quad (5)$$

where

$c_{it_{max}}$ : maximum var compensation of the FACTS device  $i$

## 2.3 Operating Constraints

According to the previous assumption, state B is eliminated to simplify the problem. Therefore, the operating constraints described in this section are defined only for states A and C. For each individual state, two target points are defined, the nominal load operating point with ( $\lambda = 1$ ) and point of collapse with ( $\lambda = \bar{\lambda}$ ) as shown in Fig.1. Note that, the superscript  $k$  refers to contingency  $k$  and notation “ $\bar{\lambda}$ ” represents voltage collapse point for each state.

At the nominal load operating point for state A and C, a set of the equality and inequality constraints is written as:

$$\begin{aligned} f(x, l, p, s, c) &= y_b + (\lambda - 1)y_d - s - f_{pflow}(x, p, c) = 0 \\ g(x, l, p, s, c) &\leq 0 \end{aligned} \quad (6)$$

where

$x$ : state variables vector (voltage)

$\lambda$ : load parameter value, ( $\lambda = 1$  at base case)

$y_b$ : base case load

$y_d$ : load direction vector

$s$ : load shedding vector

$c$ : control vector of the FACTS devices

$p$ : control parameter vector excluding FACTS devices

$f_{pflow}$ : power flow equation (equality constraints)

$g$ : bounds of all the state and control variables

At the point of collapse for state A and C, a set of the equality and inequality constraints is written as:

$$\begin{aligned} h(\bar{x}, \bar{\lambda}, \bar{p}, \bar{s}, \bar{c}) &= 0 \\ r(\bar{x}, \bar{\lambda}, \bar{p}, \bar{s}, \bar{c}) &\leq 0 \end{aligned} \quad (7)$$

where

$h$ : a set of conditions for the point of collapse

$r$ : bounds of all the state variables and control variables

## 2.4 Base Case Operation Subproblem

The objective is to minimize the sum of the total amount of the production cost, power losses and loading margin cost while satisfying network performance constraints described by (6) and (7). This problem may be formulated as:

$$\text{minimize } F_A = F_{EC}(x_A) + \omega(\bar{\lambda}_A) F_{BD} \quad (8)$$

subject to

$$f_A(x_A, l, p_A, 0, c_A) = 0 \quad (9)$$

$$\begin{aligned} g_A(x_A, l, p_A, 0, c_A) &\leq 0 \\ 0 &\leq c_A \leq c_{lt} \\ h_A(\bar{x}_A, \bar{l}_A, \bar{p}_A, 0, \bar{c}_A) &= 0 \\ r_A(\bar{x}_A, \bar{l}_A, \bar{p}_A, 0, \bar{c}_A) &\leq 0 \\ 0 &\leq \bar{c}_A \leq \bar{c}_{lt} \end{aligned} \quad (10)$$

Where  $F_{EC}$  is the production or power losses cost and  $(F_{SM} = \omega(\bar{l}_A)F_{BD})$  is the load margin cost.

### 2.5 Post Contingency Corrective Control Subproblems

As mentioned before, it is assumed that a contingency occurs and proceeds the system to the corrective state directly. If the system encounters an operating condition for which the system constraints are not satisfied, all the control variables including load shedding are readjusted to satisfy these constraints. Therefore, the objective is to minimize the sum of the total amount of these control variables and load margin cost. The formulation of the this problem can be stated as:

$$\begin{aligned} &\text{minimize} \\ &F_B(p_A, p_C^{(k)}, s_C^{(k)}, c_A, c_C^{(k)}, \bar{l}_B^{(k)}, \bar{l}_C^{(k)}) \\ &= \alpha^{(k)}(1 - \beta^{(k)}(\bar{l}_B^{(k)}))F_{C0}(p_A, p_C^{(k)}, s_C^{(k)}, c_A, c_C^{(k)}, \bar{l}_C^{(k)}) \quad (11) \end{aligned}$$

$$F_{C0} = \{F_{SH}(s_C^{(k)}) + F_{SM}(\bar{l}_C^{(k)}) + F_{CL}(p_A, p_C^{(k)}, c_A, c_C^{(k)})\}$$

$$F_{CL} = \sum_i \mu_{pi} (p_{Ci}^{(k)} - p_{Ai}) + \sum_j \mu_{cj} (c_{Ci}^{(k)} - c_{Ai})^2$$

subject to

1) nominal load operating point constraints for contingency k

$$\begin{aligned} f_C^{(k)}(x_C^{(k)}, l, p_C^{(k)}, s_C^{(k)}, c_C^{(k)}) &= 0 \\ g_C^{(k)}(x_C^{(k)}, l, p_C^{(k)}, s_C^{(k)}, c_C^{(k)}) &\leq 0 \\ 0 &\leq c_C^{(k)} \leq c_{lt} \end{aligned} \quad (12)$$

2) voltage collapse point constraints for contingency k

$$\begin{aligned} h_C^{(k)}(\bar{x}_C^{(k)}, \bar{l}_C^{(k)}, \bar{p}_C^{(k)}, \bar{s}_C^{(k)}, \bar{c}_C^{(k)}) &= 0 \\ r_C^{(k)}(\bar{x}_C^{(k)}, \bar{l}_C^{(k)}, \bar{p}_C^{(k)}, \bar{s}_C^{(k)}, \bar{c}_C^{(k)}) &\leq 0 \\ 0 &\leq \bar{c}_C^{(k)} \leq \bar{c}_{lt} \end{aligned} \quad (13)$$

Where:  $F_{CL}$  and  $F_{SM}$  are the control and load margin costs.

### 2.6 Overall Problem Formulation

The overall problem may be stated as

$$\text{minimize } F = F_{lt} + F_A + \sum_{k=1}^m F_C^{(k)}$$

subject to

Eq.(5) rewritten as  $\{0 \leq c_{lti} \leq c_{ltmax} \text{ for each } i \in \Omega$

$$\text{Eq.(9-10) rewritten as } \begin{cases} G_A(z_A) \leq 0 \\ 0 \leq C_A \leq [c_{lt}; c_{lt}] \end{cases} \quad (14)$$

$$\text{Eq.(12-13) rewritten as } \begin{cases} G_C(z_C) \leq 0 \\ 0 \leq C_C \leq [c_{lt}; c_{lt}] \end{cases}$$

where

$$z_A = [(x_A, p_A, c_A); (\bar{x}_A, \bar{l}_A, \bar{p}_A, \bar{c}_A)]$$

$$C_A = [c_A; \bar{c}_A]$$

$$z_C = [(x_C, p_C, c_C, s_C); (\bar{x}_C, \bar{l}_C, \bar{p}_C, \bar{s}_C, \bar{c}_C)]$$

$$C_C = [c_C; \bar{c}_C]$$

### 3. FACTS DEVICES CANDIDATE SITES SELECTION

A common practice in solving a large-scale VAR allocation problem is to select in advance a set of candidate sites. This process when performed properly is effective for limiting a search space and for reducing the computation time. Actually, the set of candidate site  $\Omega$  generally can be kept small even for large-scale systems. However, it is a fact that improper selection of  $\Omega$  would lead to an unsuitable solution from an economical viewpoint. Then, a critical step in our solution algorithm is the pre-selection of set  $\Omega$  for installing new devices. In this paper, candidate sites for installing SVC type are pre-examined for the most severe contingencies. The severity of contingency is evaluated in terms of the load margin just after the event. The following strategy is used as preliminary step in the proposed solution algorithm:

**SVC Set:** Since SVC is a voltage control device, the participation factor [13] is used as an index for controllability of the voltage at the nose point. The participation factors are computed using the right and the left eigenvectors of the Jacobian corresponding to the zero eigenvalue at the nose point. A candidate set is decided related to the highest participation factors.

### 4. SOLUTION ALGORITHM

The optimization problem represented by equation (14) is a large-scale MINL programming problem. The GBD technique has been applied in [11] to show the feasibility and solvability of this new formulation. However, the computational experience indicated that the non-convexity of the problem might appear for some system conditions and then leads to divergence problem. Therefore, a hybrid genetic algorithm based on successive linear programming is presented in

this section as a global solution method to avoid this problem.

A two level hybrid genetic algorithm/SLP method is proposed to solve the multi transition states problem described by Eq. (14) as shown in Fig.3. In the first level, the GA is employed to select the candidate sites and to adjust VAR amount of the FACTS devices to be installed in the system, whereas each individual in the population of the current generation represents a candidate solution. Then, this candidate selection is passed as a common candidate selection to all transition states under investigation. According to this common candidate selection, the base case sub-problem (8-10) and  $m$  contingency states sub-problems (11-13) are solved individually in the second level using SLP which is known as a fast and robust optimization method for nonlinear problems. Based on the optimization, the fitness of each individual on the population of the current generation is evaluated in terms of the operating costs associated with each state tested and investment cost. Then, the results are passed to the first level, where the genetic algorithm operators, which include reproduction, crossover and mutation operators are applied producing the next generation. These procedures are repeated till the termination criterion is satisfied.

The procedure of the suggested hybrid genetic algorithm/SLP

- 1- Randomly generate the initial population with each individual representing a candidate solution.
- 2- For each individual of the population, solve independently the base case sub-problem (8-10) and  $m$  contingency states sub-problems (11-13) using SLP.
- 3- Compute the fitness value of each individual using the inverse of the total objective function  $F$  in (14) and assign the individual of the highest fitness to the solution set.
- 4- Apply reproduction, crossover and mutation operators to obtain next generation.
- 5- If generation number is less than maximum generation go to step 2. Otherwise, go to step 6.
- 6- Retrieve the individual of the highest fitness from the solution set as a final solution.

Two version of the GA algorithms “ simple genetic algorithm and modified genetic algorithm” were implemented to show the feasibility of the proposed method. The main difference between the two versions lies in the string representation. These two versions are explained briefly as follows.

#### 4.1 Simple Genetic Algorithm (SGA)

In this version, the binary bit string representation is used; whereas each chromosome contains a number of sub-strings

equal to the number of the candidate sites of the FACTS devices. Each sub-string is in the form of binary corresponding to the amount of the VAR to be installed. For example, the chromosome shown in Fig.4 represents a candidate solution for 5 candidate buses for installing FACTS devices, where each  $c_{it}$  is represented by four digits and the corresponding VAR amount of  $\{ c_{it1}, c_{it2}, c_{it3}, c_{it4}, \text{ and } c_{it5} \}$  respectively, with

$c_{it_{\max}}$  equal 0.3 and  $c_{it_{\min}}$  equal zero. This representation is used in the proposed algorithm to find the optimal solution. The genetic algorithm operators in this version are described as follows

- 1) **Evaluation Function:** The inverse of the objective function  $F$  is used to compute the fitness value of each individual on the population.
- 2) **Reproduction:** According to their fitness values; the strings will be copied in the mating pool. The higher the fitness value is the more likely its selection. The biased roulette wheel is used in this paper to select mats.
- 3) **Crossover:** Crossover is performed on each randomly selected pair in the mating pool. Each pair of strings would swap their bits according to the crossover probability. The uniform crossover [14] is used in this study.
- 4) **Mutation:** A mutation is random alternation of bit of string position. At each bit position of chromosome, the bit will be changed from 1 to 0 or vice versa if a uniformly distributed random number from  $[0,1]$  is less than probability of mutation.

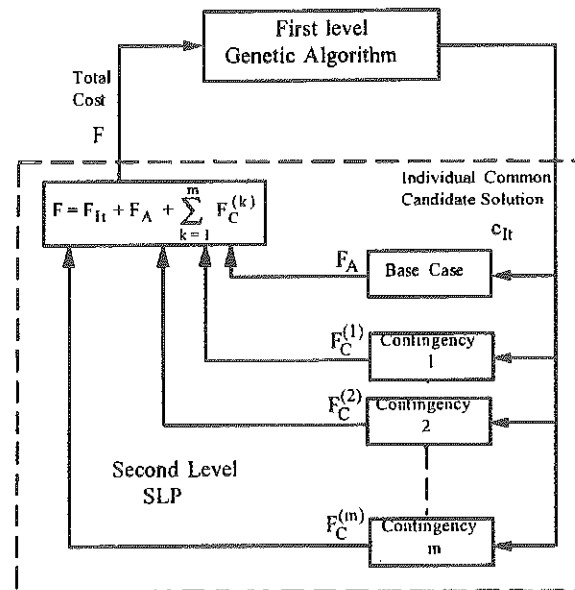


Fig.3 Two level hybrid GA/SLP iterative procedure



#### 4.2 Modified Genetic Algorithm (MGA)

In this version the string representation is performed according to two steps. The first step considers the new sites of the FACTS devices while the second step considers the VAR amount associated to these new sites. In the first step, a population of chromosomes is randomly generated in the binary coded domain, whereas each chromosome contains a number of bits, each of which corresponding to candidate site of FACTS. In the second step, the VAR amount of each FACTS device to be installed according to the first step is selected randomly from a set representing the standard sizes of the available FACTS. By so doing, each individual of the initial population of the modified genetic algorithm represents a candidate solution. For instance, the chromosome shown in Fig.5 represents a candidate solution for 5 candidate buses for installing FACTS devices, where each installed  $c_{it}$  is randomly chosen directly from the available standard FACTS device set [0.02, 0.04, 0.06, 0.08, ..., 0.28 and 0.3]. This representation is used in the proposed algorithm to find the optimal solution. In this representation method, the crossover is performed on each randomly selected pairs in the mating pool; according to the random position of crossover point, each pair of the strings would swap their VAR amount and sites as shown in Fig.6. Usually, in the binary bit representation, the mutation is performed on random positions to change it from 1 to 0 and vice versa according to mutation probability value. The mutation used in this version is exactly the typical one except that the random positions chosen are changed from zero to a randomly selected value and vice versa as shown in Fig.7.

|             |             |             |             |             |
|-------------|-------------|-------------|-------------|-------------|
| <u>0101</u> | <u>1111</u> | <u>1011</u> | <u>1001</u> | <u>0000</u> |
| $c_{it1}$   | $c_{it2}$   | $c_{it3}$   | $c_{it4}$   | $c_{it5}$   |

Fig.4 Chromosome encoding in SGA

|             |           |             |           |             |
|-------------|-----------|-------------|-----------|-------------|
| <u>0.20</u> | <u>0</u>  | <u>0.06</u> | <u>0</u>  | <u>0.28</u> |
| $c_{it1}$   | $c_{it2}$ | $c_{it3}$   | $c_{it4}$ | $c_{it5}$   |

Fig.5 Chromosome encoding in MGA

|             |      |      |      |      |      |
|-------------|------|------|------|------|------|
| parent 1    | 0.20 | 0    | 0.06 | 0    | 0.28 |
| parent 2    | 0    | 0.12 | 0.18 | 0.30 | 0.04 |
| offspring 1 | 0.20 | 0    | 0.18 | 0.30 | 0.04 |
| offspring 2 | 0    | 0.12 | 0.06 | 0    | 0.28 |

Fig.6 Crossover operator in MGA

|           |   |          |      |          |      |
|-----------|---|----------|------|----------|------|
| offspring | 0 | 0.20     | 0.04 | 0        | 0.16 |
|           |   | mutation |      | mutation |      |
| offspring | 0 | 0        | 0.04 | 0.12     | 0.16 |

Fig.7 Mutation operator in MGA

#### 4.3 Solution Algorithm for Operation Subproblems

The operation subproblems (8-10) and (11-13) are nonlinear optimization problems. The successive linear programming is used to solve these problems, where the equations are linearized around the power flow solution successively until the convergence is obtained. The linearized formulation for the corrective state subproblem is given by:

$$\begin{aligned} \text{minimize } \Delta F_B &= \Delta F_{SH} + \Delta F_{SM} + \Delta F_{CL} \\ &= \frac{\partial F_{SH}}{\partial s} \Delta s + \frac{\partial F_{SM}}{\partial \lambda} \Delta \bar{\lambda} + \left[ \frac{\partial F_{CL}}{\partial p} \frac{\partial F_{CL}}{\partial c} \right] \begin{bmatrix} \Delta p \\ \Delta c \end{bmatrix} \end{aligned} \quad (15)$$

$$\begin{aligned} A_1 \cdot [\Delta x, 0, \Delta p, \Delta s, \Delta c] &\leq b_1 \\ A_2 \cdot [\Delta \bar{\lambda}, \Delta \bar{\lambda}, \Delta p, \Delta s, \Delta c] &\leq b_2 \end{aligned} \quad (16)$$

Where  $A_1$  and  $A_2$  are the sensitivity matrices associated with (12) and (13) respectively. The similar linearization is used for the base case operation subproblem. It is noted that in the actual computation  $\Delta \bar{\lambda}$  is eliminated in (15-16) by using the sensitivity relation among loading margin  $\Delta \bar{\lambda}$  and control variables,  $\Delta s$ ,  $\Delta p$  and  $\Delta c$  [15].

The procedure used for solving each sub-problem is summarized as follows:

- 1- Solve load flow equation (6) with the available control variables ( $p$ ,  $c$ , and  $s$ ).
- 2- Compute the maximum loading point for the post-fault condition to obtain the sensitivity matrices  $A_1$  and  $A_2$ , etc. of (15-16).

- 3- Solve optimization problem (15-16) using LP. If converged, stop. Otherwise update all control variables and go step (1).

## 5. NUMERICAL RESULTS

The proposed method has been applied on the AEP-14 bus system as well as IEEE-57 bus system. The numerical results presented in this section are just considered the post-contingency sub-problems where the bus voltage magnitudes and load margin values in these cases are too small. The parameters used for both systems are given in appendix A and the parameters used for SGA and MGA versions in both systems are given in appendix B.

In the AEP-14 bus system, the contingency analysis mentioned in section 4 was carried out first over 150% nominal load level. According to these results, the most sever contingency were outage of lines [(1-2), (1-5) and (2-3)]. Then, the modal analysis was applied to rank buses according to their participation factors. The best 5 buses were selected as the candidate set to site a new SVC, which were [9,10,11,13 and 14].

The SGA and MGA versions are applied to find the optimal allocation for these 3 sever contingencies. Table 1 shows the summary of the two methods after 30 runs with 400 maximum generation per run. From this table, it can be observed that all the 30 runs find the same minimum cost for both methods except 5 trials in SGA and 7 trials in MGA within 400 generations, where, the failed trials mean slightly expensive, i.e. sub-optimal solution cases. According to the statistical results obtained for 30 trials, it is observed that the average generation to find the minimum cost is 334 in SGA and 267 in the MGA. The average generation indicated in Table.1 means that the minimum cost obtained in the reminder generations “to complete the maximum generation” is constant. This means that the SGA has more chance to find global solution but require a larger number of iterations. On the other hand, the MGA method needs less iterations to find global solution than that of SGA.

The optimal SVC allocations found by the two versions are summarized in table 2. The results indicate that the SVC allocations are 0.3, 0.3 and 0.08 pu at buses 9, 10 and 11 respectively and these reactive power are fully used for the outage of line (1-2).

The effect of the SVC's installation for the minimum bus voltage magnitude and load margin value for each contingency is listed in table 3. It is seen that voltages are violated and load margin is too small for the case without SVC's installation, where the voltage collapse is likely to occur with high probability.

The contingency costs to maintain bus voltage magnitudes and to keep the load margin within the specified value are given in Table 4 for the case without VAR expansion. It is observed that the load shedding values were very high, resulting in total expensive contingency cost, where the existing reactive power sources are not adequate to keep the voltage stability of the system. The contingency costs to keep the feasibility with SVC optimal VAR allocations are given in table 5. In these cases, the reactive power controls are adequate to maintain feasibility of the system. In other words, load shedding is not carried out, resulting in zero load shedding cost and low total contingency cost.

Table.1 Summary of SGA and MGA methods (14-bus system)

| Method | Max. generation per run | Total runs | Minimum cost | No of failed trials | Average generation |
|--------|-------------------------|------------|--------------|---------------------|--------------------|
| SGA    | 400                     | 30         | 31.55        | 5                   | 334                |
| MGA    | 400                     | 30         | 31.55        | 7                   | 267                |

Table. 2 Optimal SVC allocations and operation subproblems test results (14-bus system)

| SVC candidate buses | SVC Max Limits $C_{Hmax}$ | Optimal solution $C_H$ | Operation subproblems optimal solution $C_H$ |                  |                  |
|---------------------|---------------------------|------------------------|----------------------------------------------|------------------|------------------|
|                     |                           |                        | Cont. 1 line 1-2                             | Cont. 2 line 1-5 | Cont. 3 line 2-3 |
| 9                   | 0.30                      | 0.30                   | 0.30                                         | 0.14             | 0.14             |
| 10                  | 0.30                      | 0.30                   | 0.30                                         | 0.20             | 0.20             |
| 11                  | 0.30                      | 0.08                   | 0.08                                         | 0.05             | 0.05             |
| 13                  | 0.30                      | 0                      | 0.00                                         | 0.00             | 0.00             |
| 14                  | 0.30                      | 0                      | 0.00                                         | 0.00             | 0.00             |

Table.3 Minimum voltage magnitude and load margin values in all cases (14-bus system)

| Contingency  | Without compensation |             | After SVC compensation |             |
|--------------|----------------------|-------------|------------------------|-------------|
|              | Minimum voltage      | Load margin | Minimum voltage        | Load margin |
| 1 line (1-2) | 0.726                | 0.043       | 0.943                  | 0.201       |
| 2 line (1-5) | 0.761                | 0.094       | 0.927                  | 0.200       |
| 3 line (2-3) | 0.790                | 0.118       | 0.903                  | 0.209       |

Table.4 Contingency cost without VAR expansion (14-bus system)

| Contingency  | Load margin cost | Load shedding cost | Control cost | Total Cont. cost |
|--------------|------------------|--------------------|--------------|------------------|
| 1 line (1-2) | 0                | 316.65             | 0.015        | 316.67           |
| 2 line (1-5) | 0                | 235.68             | 0.015        | 235.70           |
| 3 line (2-3) | 0                | 224.99             | 0.015        | 225.00           |

Table.5 Contingency costs with SVC  
VAR expansion (14-bus system)

| Contingency  | Load margin cost | Load shedding cost | Control cost | VAR expansion cost | Total Cont. cost |
|--------------|------------------|--------------------|--------------|--------------------|------------------|
| 1 line (1-2) | 0                | 0                  | 0.083        | 31.360             | 31.443           |
| 2 line (1-5) | 0                | 0                  | 0.054        | 31.360             | 31.414           |
| 3 line (2-3) | 0                | 0                  | 0.053        | 31.360             | 31.413           |

In order to evaluate inherent characteristics of the propose methods, we have tested the algorithms given in section 4 without preliminary computation of candidate sites selection of section 3, i.e., all load buses are considered as a candidate site. The same VAR allocations have obtained but with a large number of generation, where the maximum generation used in this case is increased to 1200. The results imply that the proposed methods have robust computational capability regardless of the candidate site selection.

In IEEE-57 system, the contingency analysis was carried out at 1.6 nominal load level. The most sever contingencies were lines [(26-27), (25-30) and (46-47)]. The best 10 candidate sites for installing new SVC's according to modal analysis were buses [30, 29, 32, 31, 24, 33, 23, 25, 34 and 35]. The summary of the SGA and MGA in 30 runs is listed in table 6, where the maximum generation used in this case is 800. The minimum cost found by the two methods are 42.214 and the number of failed trials to find this minimum cost is 6 in SGA and 9 in MGA. While, the average generation to find optimal solution is still in MGA less than SGA. According to this result, the allocations of SVC are just 4 buses of the 10 candidates. The optimal allocations of the SVC, which are used to maintain bus voltage magnitudes and load margin value within specified value, are 0.28, 0.08, 0.24 and 0.28 pu at buses 29, 31, 24 and 35, respectively.

The contingency costs to maintain bus voltage magnitudes and to keep the load margin within the specified value are given in Table 7 for the case without VAR expansion, While the contingency costs to keep the feasibility with SVC optimal VAR allocations are given in table 8. In the later case, the reactive power controls are adequate to maintain feasibility of the system, resulting in zero load shedding cost and low total contingency cost.

Table.6 Summary of SGA and MGA methods  
(57-bus system)

| Method | Max. generation per run | Total runs | Minimum cost | No of faild trails | Average generation |
|--------|-------------------------|------------|--------------|--------------------|--------------------|
| SGA    | 800                     | 30         | 42.214       | 6                  | 710                |
| MGA    | 800                     | 30         | 42.214       | 9                  | 608                |

Table.7 Contingency cost without VAR  
expansion (57-bus system)

| Contingency    | Load margin cost | Load shedding cost | Control cost | Total Cont. cost |
|----------------|------------------|--------------------|--------------|------------------|
| 1 line (26-27) | 0                | 404.72             | 0.075        | 404.80           |
| 2 line (25-30) | 0                | 368.56             | 0.075        | 368.64           |
| 3 line (46-47) | 0                | 434.69             | 0.075        | 434.77           |

Table.8 Contingency costs with SVC  
VAR expansion (57-bus system)

| Contingency    | Load margin cost | Load shedding cost | Control cost | VAR expansion cost | Total Cont. cost |
|----------------|------------------|--------------------|--------------|--------------------|------------------|
| 1 line (26-27) | 0                | 0                  | 0.149        | 41.760             | 41.909           |
| 2 line (25-30) | 0                | 0                  | 0.152        | 41.760             | 41.912           |
| 3 line (46-47) | 0                | 0                  | 0.153        | 41.760             | 41.913           |

Finally, some comments should be added concerning the superiority of the proposed algorithms compared with GBD method used in [11]. Although the GBD method in [11] is much faster than the proposed method, the computational experience indicated that the proposed method is entirely avoid the divergence problem associated with GBD in some system conditions and a better solution is obtained.

## 6.CONCULSION

This paper is primary introduced to avoid the divergence problem appeared in the Bender Decomposition solution method used by the authors in [11], where the objective function might encounters non-convexity problem for some system conditions. Therefore, a two level hybrid GA/SLP method is presented in this paper to solve the multi transition states voltage stability constrained VAR planning problem. The GA is used in the first level to select the candidate sites and VAR amount of the FACS devices to be installed in the system. According to allocations decided by the first level the non-linear operation problems associated with every state are solved in the second level using SLP. Two versions of GA "SGA and MGA" have been examined whereas the main difference of them lies in the string representation. The computational experience for 14-AEP bus as well as IEEE-57 bus test systems indicated that the divergence problem mentioned before is completely disappeared and better solution is obtained. The proposed MGA needs less iterations to find the global solution than that of SGA.

## APPINDEXA

$V_{min}=0.9$  pu ,  $V_{max}=1.1$  pu,  $\alpha=1$ ,  $\delta=0.2$ ,  $\mu_v=2$ ,  $\mu_f=10$ ,  
 $\mu_p=0.1$ ,  $\mu_c=0.1$ , voltage collapse cost=100000 and load

shedding cost=1000 per 100 Mw.

#### APPINDEXB

Population size=50, Crossover probability=0.1, Mutation probability=0.01, Number of runs=30, Each candidate bus has 4 bits for parameter resolution in SGA and The SVC capacity available[0.02,0.04,0.06,0.08,0.10,0.12,0.14,0.16,0.18,0.2,0.22,0.24,0.26,0.28,0.3] in MGA.

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#### BIOGRAPHIES

E.E. El-Araby received B.S. and M.S. degrees from Suez Canal University, Ports Said, Egypt, in 1990 and 1996, respectively. Presently, he is preparing on a Ph.D. in the area of the application of modern heuristics to power system operation and planning at the Department of Electrical Engineering of Hiroshima University.

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## Discussions on

### Session I: FUTURE-SYSTEMS & RELIABILITY

#### Part 2

**C. Canizares** (University of Waterloo): This is a quick question for Prof. Koval. That value you have for fourteen dollars per kilowatt hour, is there a reference for that? A quick second comment is about the table you put at the end. Can that be made available for discussion? I find it very interesting.

**D. Koval**: Lot of the costs were out of Roy Billinton's survey, and those values we extrapolated. The last table comes out of the consumer reports.

**C. Vournas** (National Technical University of Athens): My question is to Mr. Toyoda. Your index started, let's say from the most reliable point of 0.2, and ended up to 0.4. So who compensates for this reduction in reliability?

**J. Toyoda**: That value is just for examples, not for the practical sense. For the practical sense, the value becomes very low. We want to make differences among the contract cases. So maybe later I would change the value to more practical ones.

**C. Canizares**: This is for Mr. El-Araby. I have a question regarding the selections of sites. You mentioned that you assume that Jacobians are singular and the use of participation factors. What do you do when the maximum loading condition is defined by limits? How do you deal with that case for selecting sites? Related to this, you assume that load shedding was one of the variables you are trying to solve for. Depending on the load shedding, the locations are going to be affected. Do you account for that at some point? The first question is regarding limits and locations. You assume singular Jacobians but there may be cases where the Jacobians are not singular but you still have the maximal loading condition. The second question is about the load shedding location.

**E. E. El-Araby**: For the first question, we face the most limits for the Var limits for our contingencies. If we have enough support for our contingencies, shedding would be zero.

**N. Yorino**: Thank you Professor Canizares. I think that your question is that there are many types of voltage limits, some with singular Jacobians but others are not. Is that right?

**C. Canizares**: Yes.

**N. Yorino**: Our proposal is basically the way of thinking for treating the FACTS allocation problem.

So, temporarily, what we can do is just to consider the voltage stability limit as singularity points. That is the formulation we proposed. For the second question, we are taking into account the load shedding points.

**S. Meliopoulos**: This question does not have to do with any specific speaker; anybody can respond to this question. The reliability indices were established years ago. Between what the utilities are doing and what some other groups such as power quality groups are doing, there seem to be two different sets of reliability criteria. Some utilities try to bridge the gap. Is it time to revisit the definitions of reliability, such as SAIFI, to include the fact that even the of temporary voltage deviations can cause some customers to be interrupted? That increases unreliability of the system. IEEE has done a lot work in the past on defining the reliability indices, but I have not seen anything recently. The only on-going thing is from power quality groups. I think it is time to bridge the gap. Any comments along this line would be appreciated.

**D. Koval**: One of the problems is that utilities do not have instrumentation to monitor momentary interruptions as fast time interruptions. You've got to measure at least a microsecond in order to capture the disturbance that interrupts the computer system in the process. For the high voltage cases, if the utility had the instrumentation, we agree that it would be nice for the utility to have all the customers have that metering technology that can capture that. Then, you can come up with some new indices. But the ones utilities are proposing now, they really have no sound basis. One of the problems is that IEEE and the regulatory body are trying to change the existing old indices by excluding certain events. If you look at it, you can't compare indices, SAIFI in one utility means something of a SAIFI of another utility, so you can't compare them, because they don't tell you what incidents they include or exclude. That's a real problem. As we're going into deregulation, nobody wants to tell you what the numbers are. So we monitor extremely well, we measure a nanosecond, but we find a lot of existing instrumentation doesn't capture, and a lot of them may not need it, and maybe some of the existing technology is changing, and the technology for measuring that is coming down. So in time I think we will have those indices for utility, but it takes time.

**J. Toyoda**: I think the reliability index depends on the industry's type. For IC technologies and for maybe the IM industry, this is different. Maybe different reliability indices will be needed. Of course this is the consumer

side reliability. For the utility side, the reliability is viewed from a different standpoint. If there are some differences, I think you can make some business chance. You have to provide for some device to improve the utility reliability close to what the consumer side of reliability is. So the important point is how to catch what type of index they need. This is dependent on the industry's type.

**H. Sasaki:** I like to ask Professor Koglin. You have compared the results of Weibull approximation and Monte Carlo simulations in a number of figures. The comparison is based on probability functions. I saw many times that for a comparison by probability distribution functions, the shape started from zero and ended in 1.0, and the shape looks similar. If we consider the probability density function, even though the probability distribution looks the same, the probability distribution density can be quite different. Probability density may be more important than probability distribution. If so, I think another comparison by the probability density function would be valuable.

**H. Koglin:** If I understood it correctly, these are two questions. One is dealing with the start in probability zero, that must not be, it is only in this example, that it seems that they are starting at zero point. The Poisson distribution as well as the Weibull distribution can have other start points.

**H. Sasaki:** I mean, for instance, in figure 6 you have shown, the two figures look quite the same. But, if you depicted it by the probability density function, the shape is quite different, I suppose. So is it reasonable to consider the reliability by the probability density functions?

**H. Koglin:** If you will make a risk management, then there is no way without distribution functions. You can not do it by the expected value or the expected value only. You have to have the distribution function.

**J. P. Paul (EdF):** I have a small detailed question. What is the comparison between the time of computations between the Bender's decomposition method and the method you used?

**E. El-Araby:** It is quite different from Bender's decomposition. The Bender's decomposition computation time is very small. We have faced some problems with the Bender's decomposition. That means time is not reliable in that case. We need a more reliable solution method.

**T. Van Cutsem:** Did you use only a small system as you presented, or did you make a real system?

**E. El-Araby:** We got the results for this medium size or small system. We need to extend it and we're doing it.

**T. Van Cutsem:** I have another question for Mr. El-Araby and his co-author. In your approach, you translate the low margin in terms of probability and in terms of cost. Referring to figure 2 of your paper, there is a Delta-parameter. Could you elaborate a little bit on how to choose this delta-parameter in a practical system? What is the physical meaning?

**E. El-Araby:** Delta is a percent, load margin value that can be negative or positive. Delta is different between the nominal load and the point of collapse. That means this is the load margin factor in this case.

**F. F. Wu:** I have a generic question. The reliability indices that we're talking about are mostly uniform for the whole system and supplier's side oriented. This is more of inheritance from how the system has been operated. This is more like a few years back, talking about China under the Socialist system, in the garment industry everybody was wearing Mao jackets. The only choice you have was whether it's black or dark blue. Now if you go to China, you see the whole fashion industry and clothing is based on the consumer choice. That led me to the thinking earlier we heard Tsoukalas mention the custom-oriented system, and also in Professor Toyoda's response pointing out that there are two groups of reliability indices from the consumer side and from the utility side. Is it time for us to think of reliability more as an attribute from the consumer needs, whether the reliability becomes part of the contract from the demand side requirement, and thinking more along the line of the consumer side reliability indices?

**H. J. Koglin:** My opinion is that the time has changed. I would like to make some remarks on the interruption cost approach. This was an approach where the interruption costs are external costs, whereas operation and investment costs are internal cost of the supplier. These three costs that mix together in one objective could work. Nowadays, they say reliability has to be paid for. That, in my opinion, can only be done when there are different tariffs for the consumers. Of course you need for each consumer the observed reliability index.

**E. El-Araby:** Value-delta is a specified load margin we need to set. We need to set this load margin value to the Delta value.

**Chairman (L. Fink):** Any other comment on that general area? All right, one last announcement. I was just being told if any of you wish to submit written discussions for any of the papers, you have two weeks to get them in parallel to the organizing committee and to the author involved, so the author of the paper has a chance to prepare the closure. So that is your last chance for extending the discussion on any of these presentations. If there is no further questions, then I will

declare the morning session closed. Thank you very much.

**Session II:**  
**PROTECTION**

Monday, August 27, 16:30–20:00

Chair: Hiroshi Sasaki



## HIDDEN FAILURES IN PROTECTION SYSTEMS

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### Introduction

The paper discusses the phenomenon of hidden failures in protection systems. It presents some representative case histories where hidden failures have been contributing factors in catastrophic failures of power systems. The paper proposes some methods of quantifying the influence of hidden failures on possible system outages. It also suggests some countermeasures which would be useful in supervising protection systems in critical locations on the power system.

### Catastrophic failures of power systems

No power system is immune to catastrophic failures. A well planned and operated power system should have few blackouts. Catastrophic failures are usually triggered by a fault when the power network is under stress. A number of new techniques for monitoring, protection and control of the power grid have been developed in recent years and application of these techniques is helping reduce the frequency and severity of catastrophic failures. Some of the newer technologies which are relevant in this regard are synchronized phasor measurements over wide areas, adaptive relaying, and monitoring and control of hidden failures in protection systems. This paper addresses the issue of reducing the likelihood of power system failures – not their total elimination.

Recent emphasis on environmental issues and licensing and regulatory approval processes have turned the interconnected power system into separate generation rich, transmission rich, and load rich regions. The tie lines which were designed to provide channels for emergency or economy transactions on a modest scale, have now become “internal” lines to the interconnected grid, and an indispensable part of the entire load serving process. This, coupled with the proliferation of generation sites, has led to unexpected degrees of stress on the power networks.

The nature and frequency of catastrophic failures depends on the developmental stage of the power system infrastructures. In some developing countries there is usually insufficient generation and transmission capacity to meet its demand. In addition, often the system is fragmented in islands, each with insufficient generation – in effect having negative margins. In such situations rotating blackouts are the normal mode of operation for the power grids. One could say that in these networks catastrophic failures are scheduled, and the customers plan their own consumption schedules accordingly. On the other hand, in developed countries

occasionally the imbalances between generation and load exist in regions where no new generation has been commissioned for decades. Mandated open access has affected the capacity of the grid to carry power from power rich regions to its load centers. Available transfer capability remains a problem – not least of all because of a lack of tools to evaluate it in real time in order to reflect accurate conditions of the network. In the absence of such tools, one must rely on pre-calculated margins, and thus the inaccuracies in the ATC may well be contributing to a perceived congestion which may not exist in reality. These conditions in developed countries are conducive to unexpected catastrophic failures when triggered by a fault.

Catastrophic failures of power networks usually follow a staged evolution process which can be summarized as follows:

- A healthy power system is put in a stressed state due to some unscheduled events: forced outages, extreme weather conditions, etc. Under conditions of stress many facilities are close to their operational limits, generation reserves are exhausted and reactive power is in short supply.
- The system operator may be in the dark as to what is happening on the power system. This may be partly due to a lack of real-time measurements, a false assessment of the system conditions by the operators, or safety margins which are in effect inadequate for the prevailing system conditions.
- A fault under these conditions may start a chain reaction. The fault may be cleared normally by its relaying, or it could be cleared by back-up relays in slower time and by tripping some extra facilities.
- Quite frequently there are hidden failures in other protection systems which cause additional false trips.
- Instabilities develop as a result of these outages, further weakening the network.
- This may lead to separation of the grid into islands of excess load or generation and eventual collapse of a load rich region into a blackout.

### Hidden failures [1,2]

The North American Electric Reliability Council (NERC) has been collecting data on major disturbances in the North American continent, and the analyses of the blackouts provided in their reports are quite interesting. It is clear that no two blackouts are similar in nature, but by a careful study of these event reports it is possible to observe some common threads. Two events are described here.

### (1) North American Blackout of 1965

This blackout is one of the watershed events in the annals of electric power engineering. (Among other changes, it brought about a move towards computer based Energy Management Systems). During November of 1965, the conditions at the Sir Adam Beck #2 substation on the Canadian side of the Niagara Falls area were as shown in Figure 1. There was local generation at the station of about 1000 MW, and 500 MW was being transmitted to Canada from the United States on the two transmission lines shown. In those days, it was common practice to use remote breaker failure protection on transmission lines. The five tapped transmission lines to the north were so equipped, and the loadability limit of the breaker failure relays was 375 MW. These relays were set in 1956, or nine years before this incident. When the relays were set, the loadability limit was considered secure, as the expected maximum load was much lower. However, over the years, the power flow on the lines had increased steadily, and the inappropriate settings of these relays were overlooked. With 1500 MW flowing on the five lines, and as is usual, the flows not dividing equally and due to the uncertainty in the relay characteristics at the reach boundary, the loading on one of the lines exceeded the relay setting and the line tripped. Immediately the power now divided among the remaining four lines, and as can be expected they all tripped. Thus there was a step change of power flow on the North American system of 3000 MW, which caused a break-up of the entire system. An area of approximately 1600km square was blacked out, and it took more than a week to restore power to all the customers affected.

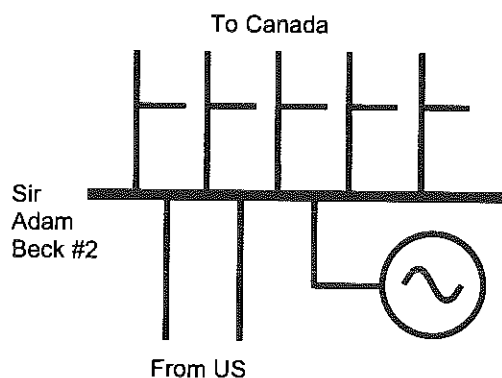


Figure 1: North American Northeast blackout in 1965, configuration at initiating event.

### (2) New-York City Blackout of 1977

This event occurred during a hot summer in 1977. The island of Manhattan in New York city was importing power from the north. (See Figure 2). The two generating stations at Buchanan substation supplied some of the power, and the two transmission lines from Millwood to the New England area supplied the rest. Because of the geography of the area, the transmission lines to the north were confined to a narrow strip of land, and were subjected to similar weather patterns. On this day, a lightning strike caused a fault and subsequent trip of a line between Buchanan (right) and Millwood. At the same time, a false trip occurred on the parallel line, thus isolating the Buchanan (right) generator. There was a mis-

wired breaker failure relay on the line going north from the Buchanan (right) substation, and it picked up when the power flow from the unit now shifted to this line. It tripped and locked out, thus removing the generator permanently from the system. (A reclosing relay was set with too small an angle, and could not permit a reclose on the first line to trip). The lightning storm continued, and now a line between Sprainbrook and Millwood developed a fault. It tripped, and as before a parallel line tripped falsely. Now the generator at Buchanan (left) was left with not outlet for its power, and once again the reclosing could not take place and this generator also was lost permanently to the system. Now the power flow shifted to the New England lines (to the right-top in the figure), and here one of the directional relays was defective, a fact that was not known. Once the power flow on the lines increased, the relay picked up and tripped one of the two lines. The remaining line to New England was severely overloaded, and its conductors sagged creating a permanent fault and it too tripped. Thus, within a short time the entire connection to the north was severed, and the only ties to Manhattan were from Long Island on the Farragut line, and from New Jersey through the phase shifting transformer. An operator, guided by pre-established operating guide lines (which were inappropriate for the prevailing stressed condition) manually tripped the Long Island connection, and now all the power having shifted to New Jersey phase shifting transformer, it overloaded, developed a fault, and tripped. This left Manhattan with a severe imbalance between its load and available generation, and the city went black. There were numerous civic disturbances following this blackout, and following a thorough review of the incident, a number of changes were instituted in the operating practices of the New York utility company.

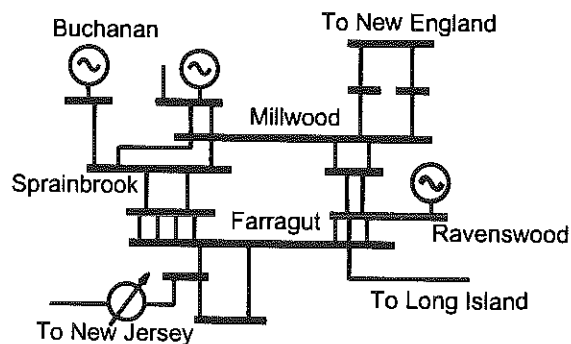


Figure 2: New York City Blackout in 1977, system configuration.

#### Lessons learned:

A careful study of several blackouts shows that a surprising number of them have some degree of involvement from over-tripping of protection systems. By itself this is not a condemnation of the way protection systems are designed, installed, or maintained. Indeed, it is surprising that a distributed autonomous system (i.e. the relaying system) whose principal function is to trip equipment and systems at very high speed reliably over-trips so few times. Nevertheless, the over-trips (often labeled false trips, sympathy trips, etc.) some times make an evolving system

event worse. It has been observed that the culprits are **Hidden Failures** in protection systems. Hidden failures are failures which are not detected when they occur, as they do nothing wrong when the system is normal. However, when a natural fault occurs and is cleared by its protection normally, the redistributed power flow establishes conditions which cause the protection systems with hidden failures to operate.

In general, the hidden failures are of two kinds:

- The settings of the protection systems are inappropriate for the prevailing system conditions. In most cases, the settings were appropriate when made, however, the system has undergone sufficient changes and the settings have not been revised. Consequently, although the relay functions correctly, in effect it has a hidden failure because of the inappropriate setting.
- There is an actual failure in the relay. The failure may be due to a failed component, due to component wear, or due to a component that has been damaged by environmental conditions or by incorrect human intervention.

In this paper we focus our attention only on protection issues, although it is clear that other issues (e.g. those related to planning for a secure system) will also require careful attention. Some ideas on protection system improvements, and the role of communication in their implementation are discussed later.

#### Hidden failures catalog

Of the cases documented by NERC during the period 1984–1988, a very large proportion of the catastrophic failures involved some contributing factors involving protection systems. The data are as shown in Table I:

Table I  
Protection system involvement in power system blackouts

| Report Year | Cases with relay system involvement |
|-------------|-------------------------------------|
| 1984        | 71%                                 |
| 1985        | 92%                                 |
| 1986        | 83%                                 |
| 1987        | 60%                                 |
| 1988        | 64%                                 |

A study of hidden failures in relays found in practice shows that a variety of reasons contribute to the hidden failures. A list of recorded cases is given in Table II.

Table II  
Causes of hidden failures in protection systems

|                          |                          |
|--------------------------|--------------------------|
| Defective Edge Connector | Open Resistor            |
| Loss of Carrier          | Broken Wire              |
| Accidental Ground        | Microswitch defective    |
| Defective SPR            | Loss of carrier          |
| Incorrect polarizing     | Noisy communication      |
| Faulty pin contact       | Faulty auxiliary contact |
| Failed switch            | Faulty contact           |
| Bent Contact             | Loss of carrier          |

As can be seen, hidden failures in protection systems can be caused by a variety of causes. However, a generic classification of hidden failures is possible.

- Hidden failures could be caused by inappropriate settings. These could be because of setting or calibration errors, or because the settings are no longer appropriate for the prevailing conditions. Such hidden failures could be controlled by more frequent reviews of settings performed by relay engineers.
- Hidden failures could be caused by equipment failures. Such failures are to be expected in any device, and to a certain extent their occurrence can be reduced by proper maintenance. However, it should be pointed out that more frequent maintenance could by itself lead to hidden failures.

#### Level of significance of hidden failures

It should be emphasized that not all potential hidden failures are equally significant from the point of view of catastrophic failures of power networks. In order to assess the significance of hidden failures, two concepts are to be taken into account:

- The region of vulnerability of a hidden failure, and
- The severity of the impact of the hidden failure.

The concept of the region of vulnerability of a hidden failure is illustrated in Figure 3.

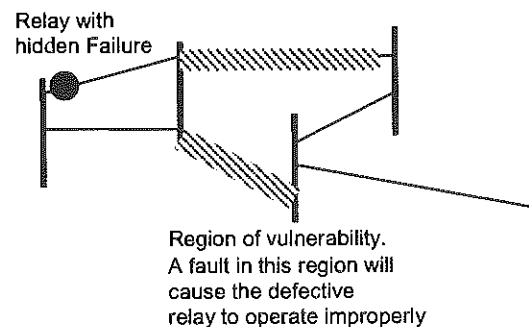


Figure 3: The regions of vulnerability of hidden Failures in protection systems.

Consider the hidden failure in the relay identified by a solid circle in Figure 3. It is suggested that this relay has a hidden failure (which of course is dependent upon the specific relay in question). For the settings in use in the relay in question, there are certain faults on the power system such that should those faults occur, the relay with hidden failures will trip falsely. The region covering all such system faults is defined as the region of vulnerability of that particular hidden failure. The shaded region shown in Figure 3 represents the region of vulnerability of the relay. Clearly the regions of vulnerability depend upon the type of relay in use, and the types of hidden failures possible for that particular relay design.

The second concept is that of the degree of severity of the impact of the hidden failure. In order to assess this severity index of the hidden failure, it becomes necessary to assume

that a fault in the region of vulnerability actually occurs, and the hidden failure leads to a false trip of the other line. The system state is then examined with these two cascaded outages. It would be desirable to carry out such a contingency analysis in real time based upon the current state of the system, but in the absence of such a capability, pre-calculated contingency analysis could be used to determine the effect of these outages on the usual categories of performance evaluation: loading, transient stability, voltage collapse, etc.

The size of the region of vulnerability, and a ranking based upon the severity of the outages caused by the hidden failure together provide a measure of the index which can be used to rank the hidden failures in order of significance for the likelihood of catastrophic failures of the power system.

### Countermeasures [3]

It must be accepted that hidden failures in protection system can not be avoided, and that these types of failures will continue to play an important role in catastrophic failures of power networks. One should then proceed to consider countermeasures which will reduce the likelihood of hidden failures' occurrence, as well as making sure that those hidden failures that do occur do not cause a disturbance to spread. Three approaches to achieving these goals are being discussed in the relaying community.

#### Adaptive Relaying

As noted above, a number of hidden failures are due to relay settings which are not appropriate for prevailing system conditions. The concept of adaptive relaying is to make an assessment of the state of the power system, and then automatically make adjustment to protection systems so that their settings are correct for the prevailing conditions. It should be remembered that most adaptive relaying concepts can only be implemented in digital relays, which have become prevalent on most power systems in modern times. Several examples of adaptive relaying have been discussed in the literature. Two such systems will be considered here.

First, consider the problem brought about by the loadability limit of relays in the 1965 blackout discussed above. Computer based relays do monitor the load of the system when the system is normal. It is certainly feasible to use incremental currents – viz. the currents from which load currents have been subtracted – for relaying functions. Such relays would have no loadability limits. An alternative is to monitor the prevailing load carried by the relays, and provide an alarm to the control center when a sustained load approaches any of the relay settings. This is not adaptive relaying in the strictest sense, as it does not make any changes to the relay automatically. But in effect, by alerting the protection engineer that a loadability crisis could occur, it forces a re-examination of the prevailing settings, and a possible revision in time to avoid a catastrophe.

A second example is that of adaptive out-of-step relaying. (See Figure 4). Out-of-step relays are designed to detect conditions when a group of machines or a portion of the power system is about to go out of synchronism with the rest of the network. Detecting this condition, the relay should

separate the affected machines from the rest of the network before a catastrophic failure of the entire network could occur. Alternatively, if the swings are judged to be stable, the out-of-step relay should suppress system separation even if some relay zones are entered by the apparent impedance seen by those relays.

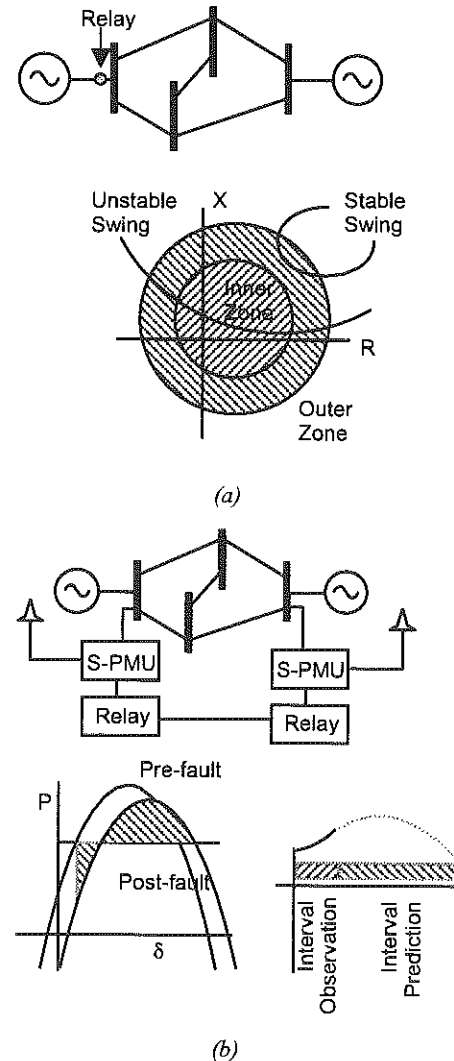


Figure 4: Adaptive out-of-step relaying using synchronized phasor measurements.

As shown in Figure 4(a), impedance relays with an outer zone and an inner zone are used to detect the out-of-step condition. If the apparent impedance crosses the outer zone but not the inner zone, the swing is deemed to be stable. On the other hand, if the outer and the inner zones are crossed, the swing is considered unstable. Based on this classification, either out-of-step blocking or tripping signals are sent to appropriate breakers. The zone settings and various timer settings are based upon numerous simulations of transient stability events performed for assumed system conditions.

Out-of-step relays are seldom very reliable in the accuracy of their decision making since very often the actual power system state is different from that which had been

simulated for determining the zone settings. One of the improvements suggested is to implement an adaptive out-of-step relaying scheme as shown in Figure 4(b). Here, the real time synchronized phasor measurements (S-PMU) from each of the machine terminals are communicated to the relays at the other terminal. The relays then calculate the outcome of the swinging that is in progress using the equal-area criterion of power system stability. Such a system has been tested at the interface between the States of Florida and Georgia.

A more interesting adaptive protection concept is illustrated in Figure 5. In most modern protection systems, the bias is in the direction of dependability: viz. a fault is cleared at high speed dependably under all circumstances. This dependability is achieved by making use of multiple protection sub-systems, all of which will trip the power system element upon detection of the fault. Thus, logically the multiple protection systems are normally connected in an 'or' configuration. This bias exists because the consequences of not clearing a fault at high speed are usually catastrophic to the power system from the point of view of stability. Under normal system conditions with sufficient transmission and generation capacity this bias is entirely appropriate. However, when the power system is stressed, the bias (which leads to increased insecurity) is inappropriate: any one of the protection systems making an error when the fault is not on the element in question would lead to a false trip, thus making the power system vulnerable to cascading failures. Under these circumstances, one should adapt the protection logic as shown in Figure 5. Upon detection at the system control center that the power system is severely stressed, a signal would be sent to key protection facilities to change their tripping logic from the 'or' function to an 'and' or to a '2 out of 3 voting' logic. Thus one would exchange a loss in dependability by accepting some risk that a fault may not be cleared, with an increased assurance that only genuine faults would lead to trip, and thus the possibility of false trips would be reduced. This is a very powerful tool in the fight against catastrophic failures of power systems.

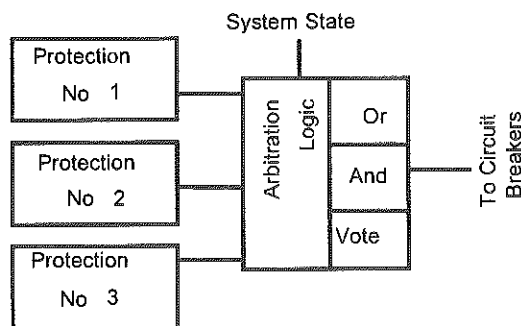


Figure 5: Adaptive control of dependability and security of protection systems.

#### Hidden Failure Monitoring and Control

As mentioned earlier, the incidence of hidden failures in protection systems can not be entirely eliminated. More frequent maintenance is not always an answer; indeed too frequent maintenance could by itself induce hidden failures in relays. One must therefore investigate other possibilities as defensive measures. An idea has been proposed whereby at

critical substations in the power system a supervisory system is imposed on certain relays whose hidden failure and a false trip can not be tolerated during a system event. In essence, the supervisory control system duplicates the algorithms of the relays in question, and if the supervisory system's decision does not coincide with that of the critical relays, they are prevented from issuing a trip.

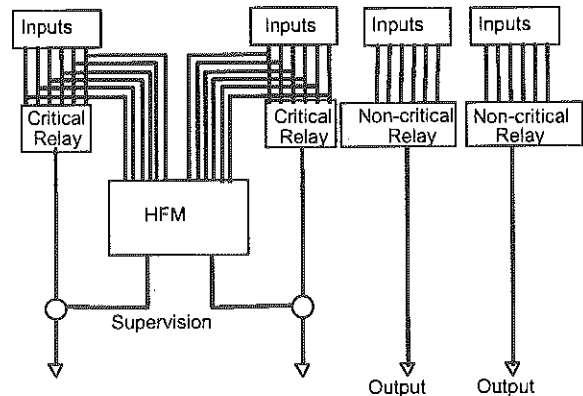


Figure 6: Principles for supervision of hidden failures in protection systems.

Figure 6 illustrates the principles involved. From a through study of the power system and the regions of vulnerability of possible hidden failures, it is determined that first two relays in Figure 6 are critical from the point of view of catastrophic failures. The input signals from those relays are supplied to a Hidden Failure Monitoring and Control system, which duplicates the relay functions. The output of the HFM system is used to supervise the output of the two critical relays.

#### Special Protection Systems (SPS) [4]

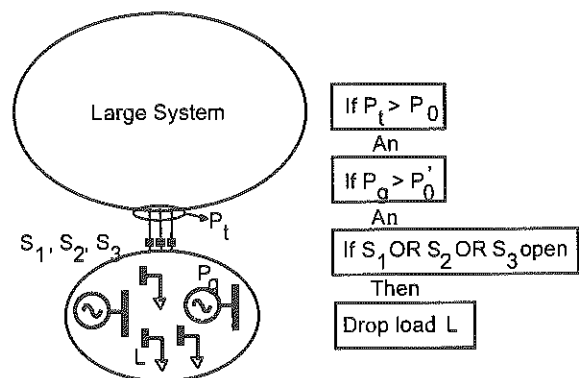


Figure 7: A typical special protection system.

These are protection systems which have been designed to steer a set of protection and control actions in a direction which will reduce the probability of a disturbance turning into a catastrophic event. Usually the controls exercised are generation or load dropping. In a complex network, whether or not to take such an action is predicated on various system conditions. Examples are system loading, loading on key transmission facilities, status of key circuit breakers and

switches, etc. These data are brought to the SPS over a communication network, and a table look-up determines the appropriate response of the SPS for the prevailing system conditions. Several tables may be stored in the SPS in order to meet the requirements of varying system conditions. As in the case of the out-of-step relaying system, the tables of the SPS are determined by prior off-line studies performed on the system for a large number of contingencies. However, if the actual system condition is different from those assumed in the studies, the SPS may well operate inappropriately for the prevailing system conditions. Once again, adaptive SPS would be a better solution. A typical special protection system illustrating these concepts is shown in Figure 7.

*Wide area measurements, communication systems, and synchronized phasor measurements*

Among the most interesting developments in the field of real-time monitoring of power systems, is the advent of synchronized phasor measurements using GPS satellite for synchronization.[5] These phasor measurement units (PMUs) provide real-time measurements of positive sequence voltages and currents at power system substation. Typical measurement windows are 1 cycle of the fundamental frequency, and the measurements can be repeated as often as 2-5 cycles. The measurements are time-stamped to a microsecond, and all measurement times are derived from the common GPS signal. Data from substations are collected at a suitable site, and by aligning the time stamps of the measurements a coherent picture of the state of the power system is created. Many applications of these measurements have been described in the reference cited.

All communication systems used in protection functions must have certain attributes. It should be noted that the amount of data transmitted for protection purposes is not excessive. The (PMU) are probably the most prolific producers of data for protection. Even so, each PMU may produce no more than two dozen 16 bit words every 20-40 milliseconds. By modern standards this is not a great data volume even if the protection function needed the data from half a dozen PMUs. Certain generation dropping and load tripping schemes may require data volumes of this magnitude. Since primary protection is not under consideration, data latency of the order of 20 milliseconds may be tolerable. The most stringent requirement in this regard comes from the adaptive out-of-step relays. If we assume that the power system swings have oscillation frequencies of the order of 1 Hz, effective control of such oscillations would require action speeds of the order 200-500 milliseconds. Certainly latency of the order of 20-40 milliseconds would be acceptable for most such controls. Multi-user communication links could be acceptable for these functions, if the latency figures could be guaranteed. In the absence of such guarantees, most protection engineers would prefer dedicated channels for protection functions.

In all cases, security of the communication channel would be of paramount importance. Failure of any one link should not affect the performance of the protection scheme which is entrusted with power system security under conditions of stress. The communication systems must also be immune to attacks from hackers. This may prove to be one

of the more troublesome requirements if multi-user communication links are used for protection functions.

Recent advances in computer relaying and communication technology have opened up new possibilities for improving the operation of power networks. In particular, these technologies could significantly reduce the incidence of major disturbances in power systems. Hidden failures in protection systems often play a crucial role in bringing about catastrophic failures. If computer relays, synchronized phasor measurements, and adaptive relaying ideas are adopted, it is possible to develop protection systems with superior performance in times of stress.

### Conclusions

The paper has highlighted the phenomena of hidden failures in protection systems as contributing factors in catastrophic failures of power networks. Hidden failures can not be completely eliminated. However, by taking a measure of their impact on the power system, several countermeasures can be applied. Among the most important recent developments are synchronized phasor measurements, adaptive relaying, and adaptive remedial action schemes (also known as special protection systems). With computer relays becoming more common, it is possible to take advantage of these new developments, and make the power systems less susceptible to catastrophic failures.

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## Wide Area Disturbances: Protection and Emergency Control

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### Introduction

System-wide power system disturbances, and their consequences, are a challenging problem for the utility industry because of the large scale and complexity of the underlying infrastructure. When a major power system disturbance occurs, protection and control actions are required to stop the power system degradation, restore the system to a normal state, and minimize the impact of the disturbance. The present control actions are not designed for a fast-developing disturbance and may be too slow. The operator must therefore deal with a very complex situation and rely on heuristic solutions and policies. Additional problems are created when alarm generation software creates an avalanche of alarms and warnings, which are sometimes related to the common cause, and the analysis of which may bring about more confusion than understanding of the evolving problem, even when its mitigation can be helped by the operator action.

Even for the best planned system, unpredictable events can stress the system beyond the planned limits. Some of the reasons why completely reliable operation cannot be achieved are: i) Practically an infinite number of possible operating contingencies; ii) Unpredictable changes, due to the evolving nature of power systems, which may differ dramatically from the forecasts; iii) A combination of unusual and undesired events (for example, human error combined with heavy weather and scheduled or unscheduled maintenance outages of the important system element); iv) Reliability design philosophy that is pushing the system close to the limits brought about by economic and environmental pressures.

In this paper, we provide an overview of some of the presently used wide area protection and emergency control techniques in power networks. We also provide, as an example, illustration of an application in power system voltage stability emergency control, using a network of phasor measurement units deployed as an adaptive distributed monitoring and control tool.

### Causes of Disturbances and Remedial Measures

The time scales of their action usually separate phenomena that create wide area power system disturbances: transient (fast) disturbances, small dynamic disturbances, and voltage disturbances (slow). By the

nature of their effects on the system, disturbances could be overloads, power system cascading, etc. They are mitigated using a variety of protective relaying and emergency control measures.

Transient instabilities are widely regarded as representing various situations involving the rotational dynamics of the synchronous generators (and sometimes other rotating machines) in the power system. Out-of-step protection as it is applied to generators and systems, has the objective to eliminate the possibility of damage to generators as a result of an out-of-step condition. In case the power system separation is imminent, it should take place along boundaries, which will form islands with matching load and generation. Distance relays are often used to provide an out-of-step protection function, whereby they are called upon to provide blocking or tripping signals upon detecting an out-of-step condition.

Voltage stability is defined by the System Dynamic Performance Subcommittee of the IEEE Power System Engineering Committee [1] as the ability of a system to maintain voltage such that when load admittance is increased, load power will increase, and so that both power and voltage are controllable. Also, voltage collapse is defined as being the process by which voltage instability leads to a very low voltage profile in a significant part of the system. It is accepted that this type of instability is exacerbated by the load characteristics, as well as balance of reactive power "sources" and "sinks" in the system, as opposed to the transient (angular) instability, which is caused by the rotor dynamics of generators. The risk of voltage instability increases as the transmission system becomes more heavily loaded. The typical scenario of these instabilities starts with a high system loading, followed by a relay action due to a fault, a line overload or reaching an excitation limit. Voltage instability can be alleviated by a combination of the following remedial measures means: adding reactive compensation near load centers, reinforcing the transmission line network, varying the operating conditions such as voltage profile and generation dispatch, coordinating relays and controls, and load shedding. Most utilities rely on planning and operation studies to guard against voltage instability. Many utilities utilize localized voltage measurements in order to achieve load shedding as a measure against incipient voltage instability [2].

<sup>1</sup> Please see the acknowledgements for the complete list of contributing authors.

Outage of one or more power system elements due to the overload may result in overload of other elements in the system. If the overload is not alleviated in time, the process of power system cascading may start, leading to power system separation. When a power system separates, islands with an imbalance between generation and load are formed with a consequence of frequency deviation from the nominal value. If the generators cannot handle the imbalance, load or generation shedding may be necessary. A special protection system or out-of-step relaying can also start the separation of the system. A quick, simple, and reliable way to re-establish active power balance is to shed load by underfrequency relays. There are a large variety of practices in designing load shedding schemes based on the characteristics of a particular system and the utility practices [3], [4].

### Technology Infrastructure

Recent advances in the measurement technology, computerized monitoring, precise synchronization and time-tagging techniques, fast broadband communication technology, and advances in analytical techniques for monitoring, diagnostics and control of large scale power networks represent the framework for development of a new generation of protective relaying and emergency control devices. We briefly review some of them in the following text.

#### Phasor Measurement Technology

The technology of synchronized phasor measurements is well established by now. The essential feature of the system is that it measures positive sequence (and negative and zero sequence quantities if needed) voltages and currents of a power system, with synchronized measurements being obtained at widely separated distances between measurement locations. Very fast recursive Discrete Fourier Transform (DFT) calculations are normally used in phasor calculations on sliding time windows.

$$\tilde{X}_1^{new} = \tilde{X}_1^{old} + k_a \Delta x_a + k_b \Delta x_b + k_c \Delta x_c$$

Here,  $\tilde{X}_1^{new}$  are the positive sequence phasors, and the  $k_x$  are appropriate Fourier coefficients. The  $\Delta x_i$  are the changes in the samples of the various phase quantities. The synchronization is achieved through a Global Positioning Satellite (GPS) system. It is possible to use other synchronization signals, if these become available in the future, provided that a sufficient accuracy of synchronization could be maintained.

Figure shows a typical synchronized phasor measurement system configuration. The GPS transmission is received by the receiver section, which delivers a phase-locked sampling clock pulse to the Analog-to-Digital converter system. The sampled data are converted to a complex number (in rectangular coordinates), which represents the phasor of the sampled wave form. Phasors of the three phases are combined to produce the positive sequence measurement.

Any computer based relay which uses sampled data is capable of developing the positive sequence measurement. By using an externally derived synchronizing pulse - such as from a GPS receiver - the measurement could be placed on a common time reference. Thus, potentially all computer based relays could furnish the synchronized phasor measurement. When currents are measured in this fashion, it is important to have a high enough resolution in the Analog to Digital converter to achieve sufficient accuracy of representation at light loads. It is found that a 16-bit converter (either a true 16-bit, or a dynamic ranging converter with equivalent 16-bit resolution) provides adequate resolution to read light load currents, as well as fault currents.

#### Communication Technology [12], [13]

Communications systems are essential component of a wide area relay system. These systems distribute and manage the information needed for analysis and control/protection of the network.

Since reliability is one of the most important aspects of the protective relaying system, communication infrastructure must be designed around them to have a reliability superior to the one of the protective relaying systems. This is especially the case when communication is needed to be part of a relay trip decision. However, the communication system should be designed to be independent of the relay system and especially of its failure modes. Common failure modes between the power and communication systems have been a frequent source of problems in the past.

To meet these difficult requirements, the communications network needs to be designed for fast, robust and reliable operation. A number of factors contribute to achieve these objectives: type and topology of the communications network, communications protocols and media used are among the most important. The communications system speed, expressed in bits per second in digital systems or hertz in analog systems, is a function of the communication protocol and the media bandwidth, the frequency and volume of information communicated and the handling of communication errors.



Presently, electrical utilities use a combination of analog and digital communications systems for their operations consisting of: power line carriers, radio channels including microwaves, leased/ switched/ dedicated phone lines and optical multiplexers. Providing the type and volume of information is adequate any of these systems will perform well in a wide area protection and control system.

Optical systems offer the most promising communication media to an electrical utility due to its immunity to electromagnetic interference, its immunity to fading (like radios) and its extremely large bandwidth.

Optical networks are now well established in electrical utilities throughout the world under two similar standards: 1) Sonet (Synchronous Optical Networks) is the American system under ANSI T1.105 and Bellcore GR Standards; 2) SDH (Synchronous Digital Hierarchy) under the International Telecommunications Union (ITU) Standards.

Sonet systems comprise a transport overhead for network management functions, with the remaining 97% of the data capacity for payload data. The payload can be subdivided to provide a variety of services such as voice, data and video. These services also include different multiplexing technologies such as dedicated links, and shared links for packet services like ATM and IP (Ethernet).

The transmission rates of Sonet systems are defined as OC<sub>x</sub> (Optical Carrier x, x=1...768); with OC 1=51.84Mbps and OC 768=39.8 Gbps. Available in the market and specially designed to meet the electrical utility environment are Sonet systems with bit rates of OC1=51.8Mbps and OC3=155Mbps and shortly OC 12.

Generally, Sonet and SDH networks are based on ring topology. However, a typical end to end network may consist of a mix of topologies: trees, rings, and meshes.

Self healing (or survivability) capability is a distinctive feature of Sonet/SDH networks made possible because of its ring topology. This means that if communication between 2 nodes is lost the traffic between them switches over to the protected path of the ring. This switching to the protected path is made as fast as 4ms, perfectly acceptable to any wide area protection and control.

Communication protocols are an intrinsic part of modern digital communications. Most popular protocols found in the electrical utility environment and suitable for wide area relaying and control are: DNP, Modbus, IEC870-5 and UCAVer2/MMS.

UCAVer2/MMS protocol is the result of an effort between utilities and vendors (coordinated by EPRI). It addresses all communication needs of an electric utility. Of particular interest is its 'peer to peer' communications capabilities that allows any node to exchange real time control signals between nodes on a communications network, including a wide area network.

Information and data between utilities are exchanged using an special protocol known in America as ICCP (Inter Control Center Protocol) or TASEII in Europe.

### Special Protection Systems (SPS)

The following definition of a special protection system comes from a NERC planning standard.

"A special protection system (SPS) or remedial action scheme (RAS) is designed to detect abnormal system conditions and take pre-planned, corrective action (other than the isolation of faulted elements) to provide acceptable system performance". Note that this definition specifically excludes the performance of protective systems to detect faults or remove faulted elements. It is system oriented both in its inception and in its corrective action. Such action includes, among others, changes in demand (e.g. load shedding), changes in generation or system configuration to maintain system stability or integrity and specific actions to maintain or restore acceptable voltage levels. One design parameter that sets these schemes apart is that many of them are "armed" and "disarmed" in response to system conditions. For example, a watchdog type of scheme may be required and armed at high load levels, but not at lower load levels. Some SPSs are armed automatically by the system control center computer, others require human operator action or approval, others are manually operated and some are armed all the time.[1]

NERC further defines the standards to which an SPS shall adhere. In part, they are:

- An SPS shall be designed so that cascading transmission outages or system instability do not occur for failure of a single component of an SPS which would result in failure of the SPS to operate when required.
- All SPS installations shall be coordinated with other system protection and control schemes.
- All SPS operations shall be analyzed for correctness and documented.

Reference [1] reports on the experience of 111 SPSs and lists the most common schemes being used as follows:

|                                |       |
|--------------------------------|-------|
| • Generator rejection          | 21.6% |
| • Load rejection               | 10.8% |
| • Discrete excitation control  | 8.0%  |
| • System separation            | 6.3%  |
| • Stabilizers                  | 4.5%  |
| • HVDC controls                | 3.6%  |
| • Out-of step relaying         | 2.7%  |
| • Dynamic braking              | 1.8%  |
| • Generator runback            | 1.8%  |
| • VAR compensation             | 1.8%  |
| • Combination of schemes       | 1.7%  |
| • Load and generator rejection | 0.5%  |
| • Turbine valve control        | 0.3%  |
| • Underfrequency load shedding | 0.2%  |
| • Others                       | 12.6% |

The preponderance of the first two schemes is not surprising. The fundamental cause of wide-area outages, almost by definition, is the unbalance between generation and load following the loss of a line or generator due to correct operation following a fault or incorrect operation by human error, hidden failure, etc.. Therefore, an SPS seeks to correct this unbalance by removing load or increasing generation. In this survey, a distinction was made between direct load rejection, i.e. removing pre-planned customers through controls, and automatic under-frequency load rejection if the unbalance results in decreasing frequency. The underfrequency tripping of load may not be considered by everyone as an SPS since it is installed by many utilities as a normal protective measure.

An increasingly popular SPS is the separation of the system into several self-sufficient islands, leaving the faulted area to fend for itself, thus greatly reducing the impact of an outage. The use of the Global Positioning Satellite to synchronize relays across the system and adaptive digital relays makes this scenario particularly attractive.

The concept of out-of-step relaying has been known for some time. However, the specific setting philosophy has been a major problem in applying it. This has not changed very much as indicated by the low (2.7%) experience level.

Combining all of the schemes applied to the turbine-generator results in a respectable experience factor (36.9% from [1]). This has become feasible by the introduction of reliable and fast-acting electronics. Fast valving and dynamic braking are particularly noteworthy as methods to reduce generator output without removing

the unit from service and thus allowing for rapid restoration.

The reliability of SPS was addressed in [1] and indicates that the equipment and schemes perform very similarly to traditional protective schemes. System conditions requiring action does not occur often, but when it does occur, the SPS usually performs its function correctly. The most common failure (43% of those responding) was hardware failures with human failure (20%) next. Inadequate design accounted for about 12% of the failures and incorrect setting less than 10%.

In this section all possible protective actions against wide area disturbances that we have been able to find during the work have been listed, commented, and evaluated. They mainly deal with curative actions.

#### *Generator Rejection Schemes*

Generator rejection schemes are an effective means of maintaining system stability and avoiding wide area disturbances. They are based on the principle that rapidly disconnecting some generation can significantly reduce the amount of power that flows through a transmission path that suffers reduced capacity (due to a local disturbance such as a short circuit) while having relatively small effect on the load/generation balance in a large interconnected system. The rapid reduction in power flow through a path with suddenly reduced capacity reduces the probability of large power swings leading to instability.

Generator rejection schemes are clearly wide area schemes since the location of the transmission disturbance that requires generation rejection may be several hundreds or even a few thousand kilometers distant from the generation plant. The need for the schemes and amount of generation that needs to be shed for various contingencies depends significantly on the transmission load flow pattern, therefore the schemes are usually capable of being armed and/or adjusted by operators at the transmission control center.

The type of generation rejection scheme depends to a large extent on the type of prime mover that drives the generators. Shutdown of large steam turbine generators can be extremely costly, may result in very long restart times, and also subjects the turbogenerator set to significant thermal stresses. On the other hand, most hydroelectric generators can be relatively easily shut down and quickly restarted. There is however some detrimental effect on a hydro generator that may be subjected to severe overspeed if the unit breaker is opened under high load conditions. Generator rejection schemes could be classed into three categories as follows: a)

Schemes that depend on the status of the transmission paths; b) Schemes that determine the approach of transient instability; c) Hybrid schemes that depend on transmission path status and the type of disturbance.

### *Load Rejection Schemes*

Load rejection is a protection system designed to trip load following the loss of a major supply to the affected power system area. The major supply deficiency may be caused by the loss of generation or key transmission facilities. Load rejection may be also initiated to alleviate overload conditions of power system elements. It can also be initiated when certain power flow thermal interfaces are exceeded. LR systems redundancy may be required if a potential inter-area impact can be initiated by a normal contingency. Regional Reliability Councils usually have requirements involving such protective or control schemes. They may be considered as part of the Special Protection Systems (SPS) or Remedial Action Schemes (RAS) discussed above (below?). Load rejection systems are completely separate from automatic under frequency load shedding programs.

### *Stabilizers*

The addition of power system stabilizers (PSS) to the automatic voltage regulators on generators in the power system to damp low-frequency oscillations is common. Conventional PSS design uses feedback of local measurements to damp the oscillations. When inter-area oscillations are involved, tuning the feedback gains of the PSS can be challenging. Occasionally stabilizers have had to be retuned as system conditions evolve. A possible improvement in PSS design is to include remote phasor measurements in the input signals to the PSS. Even with conventional PSS there are questions concerning the optimal location of the PSS to damp inter-area oscillations. With both the PSS location and the choice of remote measurement it is possible to effectively damp the desired inter-area oscillation.

In [14] an adaptive tuning technique was used to design both a conventional PSS and a remote feedback controller (RFC) for a small system. The accelerating power of a local and a remote machine were used as inputs to the RFC. The RFC was robust over a broad range of operating points of the model system.

### *Out-of-step relaying [9], [10], [11]*

A loss of synchronism condition occurs when generators in one part of the network accelerate while other generators somewhere else decelerate thereby creating a situation where the system is likely to separate in 2 parts.

The conventional relaying approach for detecting loss of synchronism is by analyzing the variation in the apparent impedance as viewed at a line or generator terminals. Following a disturbance this impedance will vary as a function of the system voltages and the angular separation between the systems.

Out of step, pole slip or just loss of synchronism are equivalent designations for the condition where the impedance locus travels through the generator. When the impedance goes through the transmission line the phenomenon is also known as power swing. However, all of them refer to the same event: loss of synchronism.

For a *stable* swing the apparent impedance moves fast at first, slowing down as a new equilibrium is reached, with system voltages not going beyond 90 degrees approximately. If the system voltages continue to drift apart a non-return point is attained where the system becomes *unstable*. When the impedance locus intersects the total system impedance line (in the RX plane) the system voltages are 180 degrees or out of phase. This point is called the system electrical center.

The philosophy behind the use of out-of-step relaying is simple and straightforward. When two areas of a power system or two interconnected systems lose synchronism, the areas should be separated in order to avoid equipment damage or a system-wide shutdown.

Ideally, the systems should be separated at such points as to maintain a balance between load and generation in each of the separated areas. To accomplish this, out-of-step tripping must be used at the desired points of separation and out-of-step blocking used elsewhere to prevent separating the system in an indiscriminate manner. Where a load-generation balance can not be achieved in a separated area and there is excess load as compared to generation, some means of shedding non-essential loads will have to be used in order to avoid a complete shutdown of the area.

The maximum rate of slip can only be obtained from transient stability studies. Only the maximum slip is of importance and need be determined. Knowing the swing loci and the maximum slip, it will be possible to obtain reasonable settings for the out-of-step relaying equipment.

### *Underfrequency Load Shedding [7], [8]*

During severe system emergencies, which result in insufficient generation to meet load, an automatic load shedding program throughout the affected area can prevent a total system collapse. It also helps to achieve fast restoration of all affected loads. The application of underfrequency relays in substations throughout the load

area, preset to drop specific percent magnitudes of load at predetermined low system frequency values, provides the simplest automatic load shedding program. Relay settings can be developed to drop the minimum load to arrest system frequency decay at a safe operating level. Additional underfrequency relays can also be applied to initiate a safe and orderly separation or shutdown if the emergency is beyond the capabilities of the load shedding program.

The load-shedding program must be coordinated with equipment operating limitations under low-frequency operation. These limitations or restrictions are primarily associated with operation of steam turbines or powerhouse auxiliaries. In general, continuous steam turbine operation should be restricted to frequencies above 58.5 Hz (60 Hz system base), and operation below 58.5 Hz should be for a limited time only, e.g. 10 minutes or less. The controlling parameter is the fatigue of turbine blades at low frequencies, which is a limitation determined by the specific turbine manufacturer. Tests on power plant auxiliary performance indicate that a limit of approximately 53-55 Hz, below which plant output begins to reduce and motors, driving constant Kva load, will see an increase in current, increasing heating and approaching overcurrent relay settings.

Following the Northeast blackout of 1965, interest in underfrequency load shedding became a dominant concern of utilities in the U.S. A PSRC survey of their plans in this regard was made in 1966. The use of such relays was accepted by a large majority of utilities but the specific application varied widely. Most utilities planned to use three frequency levels with a definite time delay over and above the operating time of the frequency sensing element of three to ten cycles (60 Hz base) although one company reported nine frequency levels. The majority selected seven to ten percent of total connected load at each frequency level. The most popular tripping frequencies were 59.1 to 59.5 Hz as the highest level and 58-59 Hz as the lowest.

A follow-up survey was conducted by the PSRC in 1974, which revealed that underfrequency relays for system preservation was universally accepted. The experience reported indicated that these relays were effective in achieving system preservation although there were some instances of malfunctioning of the relay scheme resulted in unnecessary load interruptions. These incidents were caused by connected motor or cable loads where the natural frequency was below the relay settings. The most common solution was to increase the time delay.

Load that has been shed must be restored when the system frequency returns to normal. Automatic load restoration systems are in service, which accomplish this function.

Underfrequency relays are also used for reasons other than tripping load as follows:

- Alarms to the operators
- Automatic loading of hydro plants
- Separation from neighboring utilities
- Permissive interlocks in generating stations
- Isolation of selected loads with matched generation
- Supervision of generator manual emergency trips
- Protection of large motors and generators
- Protection of generators during start-up
- Starting oscillographs

### *Undervoltage Load Shedding*

Undervoltage load shedding is an option that is sometimes used as a final means of avoiding a wide area voltage collapse when all other effective means are exhausted. The action of shedding load is no different from other load shedding schemes including underfrequency load shedding and overload load shedding. The initiation by low voltage, possibly in combination with other parameters provides the unique characteristic of this type of scheme. Detection of low voltages on the transmission system may indicate the lack of sufficient reactive power to maintain system stability. If other emergency control actions such as reactive switching, are not effective in restoring system voltages, it may be necessary to shed load in order to maintain system voltage stability. A complicating factor in load shedding schemes is that voltages may be very close to normal at the onset of voltage collapse. It is the inability of available reactive support to maintain the voltages that lead to the imminent wide area voltage collapse and blackout. Because voltage levels may be so close to normal levels at the onset of collapse, the low voltage parameter may be supplemented by other parameters, such as transmission circuit status, and/or availability of reactive power reserve. The need to measure parameters and initiate load shedding in diverse locations may require a true wide area protection system.

### *Turbine Fast Valving [6]*

The purpose of turbine fast valving is to reduce the generator output without removing the unit from service. This is desirable when the system is stressed, e.g. upon some occurrence which would result in a transient stability problem. By reducing the generator output, the stability is not endangered and the unit can be returned to full output, maintaining system security.

There are two concepts in use. TVA, for example, closes the turbine valves to a predetermined position and stays there until the operator returns the unit to a desired load

level. This procedure requires a turbine bypass system to allow the trapped steam to escape until the boiler pressure matches new load level. AEP has opted to use a momentary fast valving (MFTV) scheme, which closes the turbine valves momentarily, and then allows them to return to a predetermined position. The scheme reduces the turbine mechanical power about 50% within one second. The valves then reopen automatically to their original positions, restoring mechanical power to the pre-disturbance level in less than 10 seconds.

### Emergency Control Schemes

#### *Secondary Voltage Control*

Secondary voltage control is mainly used for controlling the overall system voltage profile in a region in such a way that maximum robustness against voltage collapse is achieved. The secondary voltage control system derives voltage set-point values for a number of pre-defined so called pilot nodes, chosen to be well representative of voltage in the region. The primary voltage control systems (tap-changer controllers and AVR of generators, synchronous condensers and SVCs) then keep the voltage at these pilot-nodes at the desired value. By distributing the reactive power generation in a suitable way, reactive power margins in the synchronised units can be optimised.

#### *Deployment Of Reactive Power Reserves*

Reactive power support in the emergency area can be achieved by:

- shunt capacitor bank connection and shunt reactor disconnection;
- shunt capacitor "boosting" by temporarily decreasing the number of series groups in a shunt capacitor bank;
- increased Mvar output from reactive power controlled machines;
- temporary reactive power overload of synchronous machines;
- decrease of real power generation to enable increased reactive power generation for generators in the emergency area, can be efficient under certain circumstances.

#### *Actions Of OLTC Transformers*

The action of the on-load tap-changers (OLTCs) operating on the power transformers at various voltage levels has the main goal to supply the load at a voltage kept within a given range, as close as possible to the rated value. For a voltage collapse scenario the bulk system

voltages are slowly decreasing while the OLTCs are restoring the distribution system voltages.

The simplest method to eliminate the OLTC as a contributor to voltage collapse is to block the automatic raise operation during any period where voltage collapse appears to be a concern. A more sophisticated use of the OLTCs, than just blocking them, could be to reduce the voltage set-point. A larger load relief can be achieved in this way. As for the blocking of OLTCs the effectiveness is largely dependant on the characteristics of the supplied system, such as type of load, degree of shunt compensation, number of OLTCs on lower levels, etc.

ENEL, Italy, describes an interesting strategy for controlling OLTCs:

- In a secure state, all OLTCs are controlled as usual. HV voltage set-points are chosen to minimise active losses in the subtransmission networks.
- In emergency conditions, EHV/HV and HV/MV OLTCs are blocked, keeping the minimum possible transformer ratio for EHV/HV transformers.
- In alert state, where credible contingencies would lead to voltage instability, the MV voltage set-points of HV/MV OLTCs are decreased while EHV/HV OLTC set-points are *increased*. The objective is to reduce reactive losses and get more reactive support from shunt elements in subtransmission networks.

#### *Active Power Support, Gas Turbines, HVDC Lines, Etc.*

Normally active power support by gas turbine start up and emergency power from HVDC lines in the critical area, are very efficient in a stressed situation. HVDC active power support can be achieved in the time scale of seconds, while the gas turbine start up process takes some minutes. A large amount of the critical situations are however of long term type and the gas turbines will have a reasonably good chance to contribute to the system stability.

#### *Rate Of Voltage Variation As A Local Collapse Criterion*

The receiving end voltage as a function of time can be used to identify, or predict, a voltage collapse situation. Since the voltage profile includes step-changes from shunt reactor and shunt capacitor switchings, as well as tap-changer operations, faults and fault clearance processes, the signal needs proper low pass filtering. On the other hand the voltage profile is affected by the slow (and even sudden) load variations and therefore also requires some sort of high pass filtering. The filtering

process will introduce an unavoidable delay with respect to the original signal and therefore increase the detection time of the collapse criterion.

### Interfaces Among Utilities, Co-Ordination

The degree of interconnection of the power systems around the world is increasing, and the systems tend to be larger and larger and stronger and stronger. On the other hand competition on the electricity market is splitting the system on different owners and operators, resulting in less exchange of information. In this environment it is extremely important to use the strengths of the interconnected system, for abnormal operation conditions, such as severe faults and voltage instability. Detailed agreements between all relevant parties involved in the power system process have to be established and accepted. The operators should also be trained in correct use of these agreements, in order to be able to use the full capability of the system in stressed situations.

### Decision Making For Curative Actions

Regarding the decision to take curative actions, it may be difficult to choose a simple criterion that accommodates the large numbers of possible system conditions (topology, load level, etc.) and incidents.

If system wide collected measurements are available more elaborate criteria may be thought of to trigger the curative action. In this respect a statistical methodology may help the protection designer to choose the appropriate criterion. Statistical methods and large data bases of system scenarios are built off-line, using numerous numerical simulations, and automatic learning methods to extract the relevant decision criterion.

### Example: Voltage Stability Margin Estimation Using Local Measurements [17]

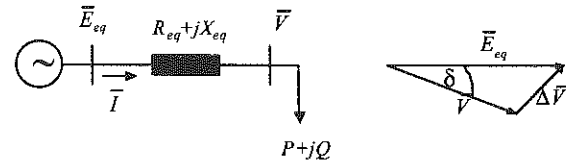
In 1997, we presented [17] the method that employs only local measurements to estimate the proximity of the system to voltage. The method is proposed for relay application.

Based on local measurements – bus voltage and load current – the proposed algorithm produces an estimation of the strength/weakness of the transmission system connected to the bus, and compares that with the local demand. The closer the local demand is to the estimated transmission capacity, the more likely to occur is the voltage instability. This information can be used for load shedding as well as other applications. The method is very attractive since it is very simple and can be applied in *real*

*time*. It does not require the network information be known (topology, loads, generators, etc.). On the other hand, the controls that use only local data are low cost and simple to build.

### Two-bus Equivalent of the System

The local voltage stability monitoring and control method is based on a two-bus equivalent, where one of the buses is the slack bus supplying a load over a single branch, as shown in the Figure below. The line and source system is represented by an impedance  $\tilde{Z}_{eq} = R_{eq} + jX_{eq}$  and voltage phasor  $\tilde{E}_{eq}$ , respectively.  $\tilde{E}_{eq}$  and  $\tilde{Z}_{eq}$  represent the equivalent of the network seen from the terminals of the load bus of interest



Load bus and the rest of the system represented with a source and a line, and the corresponding line diagram.

Simple calculation shows that at the voltage stability point, the equivalent impedance  $Z_{eq}$  is equal to the load bus impedance  $Z$  given as a ratio between the voltage  $\tilde{V}$  and the current phasor  $\tilde{I}$  measured at the bus, i.e.,  $Z = |\tilde{V} / \tilde{I}|$ .

$$Z_{eq} = Z$$

To assess the load bus distance to collapse, the corresponding agent has to track the parameters of the equivalent source  $\tilde{E}_{eq}$  and impedance  $\tilde{Z}_{eq}$  that model the rest of the system lumped together, and monitor the Impedance Stability Index (ISI) or Voltage Stability Index (VSI) defined below. The values close to one are indicative of the proximity to voltage collapse and can be used to pinpoint the system area directly associated with the collapse problem. Obviously, the smallest value among all *ISI* determines the stability of the whole system.

$$ISI = \frac{Z_{eq}}{Z} \quad VSI = \frac{V}{\Delta V}$$

Notice that  $V$  and  $\Delta V$  represent high and low voltage solution at a load bus. At the collapse point  $V = \Delta V$ . The value of parameters  $\tilde{E}_{eq}$  and  $\tilde{Z}_{eq}$  are not constant, but vary slightly and reflect changes in the power system loading.

A PMU can also determine the load margin from any current operating point to the tip of the nose curve, where voltage collapse can take place. The power margin is equal to

$$\Delta S = ZI^2 - Z_{eq} I^2$$

and represents extra MVA that can be delivered to the load before voltage collapse occurs. The ratio between the power supplied by equivalent source  $S_{eq} = E_{eq}I$  and the power actually consumed by the load  $S = VI$  will reveal power lost in the transmission. This ratio rapidly increases as the system approaches the voltage collapse.

#### Parameter Identification

The relationship between unknown parameters of the voltage source  $\tilde{E}_{eq}$  and line  $\tilde{Z}_{eq}$  modeling the rest of the system seen from the load bus is expressed with the following equation:

$$\tilde{V} = \tilde{E}_{eq} - \tilde{Z}_{eq} \tilde{I}$$

After separating the imaginary and real parts above, we obtain the system of two linear equations with four unknowns, i.e.,  $\tilde{E}_{eq} = E_r + jE_i$ , and  $\tilde{Z}_{eq} = R_{eq} + jX_{eq}$ .

$$\begin{bmatrix} V_r \\ V_i \end{bmatrix} = \begin{bmatrix} E_r \\ E_i \\ R_{eq} \\ X_{eq} \end{bmatrix} \begin{bmatrix} 1 & 0 & -I_r & I_i \\ 0 & 1 & -I_i & -I_r \end{bmatrix}$$

where  $\tilde{I} = I_r + jI_i$ , and  $\tilde{V} = V_r + jV_i$ .

Having the time tagged sequence of voltage and current phasor measurements, an agent can determine the unknowns by using a parameter identification algorithm, such as recursive least-squares (RLS), or RLS with forgetting factor. Note that all of the above quantities are functions of time and are calculated from a sliding window of discrete data samples.

The monitoring device based on the above principle can be used to impose a limit on the loading at each bus, and sheds load when the limit is exceeded. It can be also used to enhance existing voltage controllers. Coordinated control can be obtained if communication is available.

#### Numerical Example

To illustrate local voltage stability monitoring, we used the standard IEEE 39-bus system. Loading is simultaneously increased at all load buses. Limits of reactive power generation are taken into account. Voltage collapse occurred for the proportional multiplicative loading factor equal to 1.634.

The forgetting factor recursive least squares (RLS) algorithm is used to track the parameters of two bus equivalents. The parameters change with the operating conditions, especially when the reactive generation limits are encountered. Therefore, the older data should be less relevant than newer data. This is accomplished with a forgetting factor  $\lambda < 1$ , since it gives larger weight to more recent phasor measurements.

#### Adaptive Voltage Reduction and Load Shedding

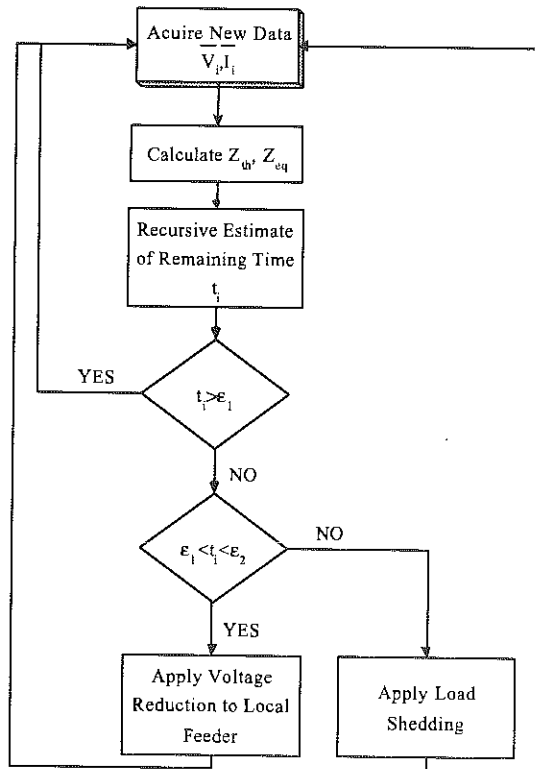
The *ISI* index is predictable in the sense that it decreases significantly as the system moves closer to the collapse point. However, its nonlinearity makes it impractical for prediction of proximity to collapse. However, having more "predictable" shape voltage magnitude  $V$  at a load bus can be used in combination with  $\Delta V$  to estimate the distance to voltage collapse from a discrete number of successive operating points by using a curve-fitting technique. The proposed method to get the "time or power margin" to the voltage collapse as "seen" from the terminals of a bus  $i$  can be explained as in the flow chart on the next page. The estimated time margin is expressed as the period in minutes upon which the system might experience collapse. Since, the  $\Delta V$  might be very sensitive to device limits, the estimate has to be revised after any sharp change in the  $\Delta V$  value.

First, at any given (current) time instant, we obtain new voltage and current phasor measurements, and calculate the elements of the two-bus equivalent, as shown above.

Then, from the knowledge of a discrete number of present and current operating state, we approximate the voltage load curves by a nonlinear function, whose form is a function of the load characteristics. To fit the function, a minimum of two points on each curve is necessary.

Upon finding the approximate voltage load curve, every PMU locally estimates the collapse point (peak of the

nose curve) and time when it will be reached, as seen from the corresponding load bus.



Voltage stability margin estimate flow chart.

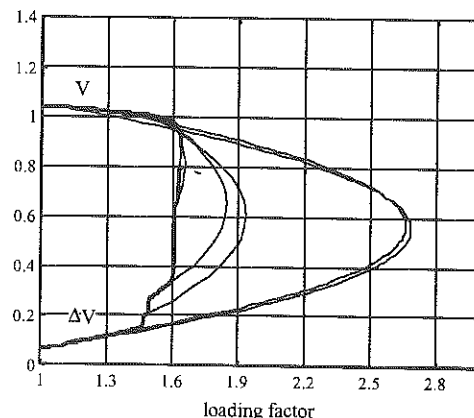
Obviously, the system collapse margin corresponds to the minimal value of the time margin estimated at every load bus. If time margin is greater than some predefined threshold value, the PMU will assume its bus not to be critical, and system to be stable. However, time margin value between two threshold values, which we may refer to as "warning" and "emergency", would be a trigger to the PMU to take immediate corrective actions at the local bus, such as voltage reduction, to prevent the system collapse. A PMU will take more severe control actions, such as load shedding, if the time margin is lower than the "emergency" value.

The effect of the control actions will be sensed immediately through new measurements of the voltage and current phasors at the corresponding load bus. This allows a PMU to evaluate the effect of its control actions and adjust them in response to the changes of estimated margin.

The Figure below illustrates the process of determining the voltage stability margin. To be consistent in this example as in all previous ones, we used the

multiplicative proportional loading factor as a parameter that drives the system to voltage stability limit. Hence, we "measured" the margin in terms of system loading, and not in terms of time. The thick solid lines in the Figure represent the voltage load curves traced at bus 23. The points on the thin line knees indicate estimates of the critical points, and therefore voltage stability margins. As the system moves toward the stability limit and the generators encounter Q-limits, the estimate of the system margin becomes more accurate. In our example, the initial estimate for the voltage stability margin was 2.68, and final 1.63.

The example shows that monitoring of the generator Q-limits is also an important part of the above procedure, for every PV-PQ transition caused by activation of generator excitation limiters would change the load margin estimates, sometimes radically. Since the procedure described above could be implemented at every load bus, redundancy of those estimates is taken advantage of to create a voting scheme for protective and emergency control actions.



Load power margin estimates for bus 23 of the 39-bus test system.

## Conclusions

The trend in power system operation and planning of the industry in restructuring is to utilize tight operating margins, with less redundancy, because of the new constraints placed by economical and environmental factors. At the same time, addition of new devices and load growth, sometimes not matched by appropriate increase of generation capacity, make the power system more complex to operate and to control, and, thus, more vulnerable to a disturbance. On the other hand, the advanced measurement and communication technology in wide area monitoring and control, FACTS devices (better tools to control the disturbance), and new analytical developments may provide better ways to detect and



control an emergency. Better detection and control strategies through the concept of wide area disturbance protection offer a better management of the disturbances and significant opportunity for higher power transfers and operating economies. Wide area disturbance protection is a concept of using system-wide, or just local information and transmitting sufficient information to a remote location to counteract propagation of the major disturbances in the power system. With the increased availability of sophisticated computer, communication and measurement technologies, more "intelligent" equipment can be used at the local level to improve the overall emergency response.

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## Wide Area Protection and Optimization

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**Abstract** - This paper describes basic principles and philosophy for wide area protection schemes, also known as Remedial Action Schemes (RAS) or System Protection Schemes (SPS). Also the issue of “power system optimization” is addressed. In the areas of power system automation and substation automation, there are two parallel trends in different directions: centralization and decentralization. More and more functions are moved from local and regional control centers towards the central or national control center. At the same time we also observe more and more “intelligence” and “decision-power” moving closer towards the actual power system process. We also see a great deal of functional integration, i.e., more and more functionality enclosed in the same hardware. This raises discussions concerning reliability (security and dependability). The main targets for this paper is therefore to:

- Sort out the terminology used in this area;
- Describe different application areas and related requirements;
- Illustrate different design principles – “top-down”, “bottom-up”, hierarchy, flat, etc., for different applications;
- Address the perspectives of the utility/user/operator versus the manufacturer/vendor view of wide area systems/equipment - and make them meet;
- Discuss suitable levels of complexity, capability, capacity, flexibility, for system protection schemes.

### Background and Introduction

There are a few basic facts and technological developments that have pushed the utility needs and the suppliers’ offers in wide area protection and control as well as for advanced SCADA/EMS systems:

- 1) Environmental concerns complicate for utilities and grid companies to improve the capability of the power system by building new lines and substations.
- 2) The de-regulated electricity market cause rather quick changes in the operational conditions. New, unknown, load flow patterns show up more frequently for the system operator.
- 3) Economical pressure on the electricity market and on grid operators forces them to maximize the utilization of the high voltage equipment, which very often means operation closer to the physical limits of the system and

its components. For the same reason there is also a wish to “push” the limits.

- 4) Reliable electricity supply is continually becoming more and more essential for the society and blackouts are becoming more and more costly whenever they occur.
- 5) Technical developments in communication technology and measurement synchronization, e.g., for reliable voltage phasor measurements, have made the design of system wide protection solutions possible. Also SCADA/EMS functions have been greatly improved, both the amount of data and the communication speed. The use of phasor measurements also provides new possibilities for state estimator functions. Specific Phasor Measurement Units (PMUs) have been developed. Their main use so far has been for WAMS (Wide Area Measurement System) applications.
- 6) There is a general trend to include into power system automation, both normal operation issues and disturbance handling.
- 7) Wide area disturbances during the last decades have forced/encouraged power companies to design system protection schemes to counteract voltage instability, angular instability, frequency instability, to improve damping properties or for other specific purposes, e.g. to avoid cascaded line trip.
- 8) A lot of research and development within universities and industry have significantly increased our knowledge about the power system phenomena causing widespread blackouts. Methods to counteract them have been or are being developed, e.g. [1, 2].

### Market Demands and Utility Needs

Based on the situation and new technology described above, grid companies can benefit a lot. Wide area protection and emergency control systems can be introduced in the power system, either

- to increase the power system transmission capability, or
- to increase the power system reliability, or
- a combination of the two.

This means that the grid company can extend the system operational limits, i.e. operate the system closer to the physical borders, without any investments in high voltage equipment. The operational criteria will change from

- “the power system should withstand the most severe credible contingency”, to

- “the power system should withstand the most severe credible contingency, followed by protective actions from the wide area protection / emergency control system”.

Certain power systems do not fulfill the design and operational criteria, which are based on the reliability requirements on the system, without installation of wide area protection (and emergency control) systems. The reliability requirements on such wide area protection systems – dependability as well as security – are extremely high.

#### *How to meet Present and Future Demands?*

Utility companies may require one package for the entire operation of the power system, including planning, operation, control, and protection – optimized on a “system” level, based on maximum profit and supply reliability. This “package” should consist of a number of integrated, product offerings and should be compatible with present equipment. This approach benefits both retrofit and new installations. To allow for retrofit, such a package should use present technology and move towards standardized communication, standard input and output format, etc.

Large utilities, such as Hydro Québec, EDF, and BPA, still design their own system protection schemes and defense plans, based on standard components available today. To make the area of system protection available also for other utilities there is a market need for dedicated system protection devices and basic system protection design structures. Such systems could be based on standardized system protection terminals, with customized functionality, tied together in a wide area protection system. Standardization, modularization and flexibility are important features in such a design.

There are basically two areas for providing solutions to the utility targets/needs presented above,

- Protection and Emergency Control, and
- SCADA/EMS-functions,

which both will be discussed in this paper.

#### **Terminology**

*Protection* is very closely related to circuit-breaker trip signals to disconnect faulty or overloaded equipment from the network, to save the component, and to re-establish normal operation of the healthy part of the power system and thereby continue electricity supply to utilities. Protection equipment is also aimed at protecting people, animals and property from injury and damage due to electric faults. The situation when a protection device triggers, is so severe that if the equipment is not tripped, it will be severely damaged or the surrounding will be exposed to serious danger.

*System protection* or *wide area protection* is used to save the system from a partial or total blackout or brown-out in

operational situations when no particular equipment is faulted or operated outside its limitations. This situation could appear after the clearance of a very severe disturbance in a stressed operation situation or after an extreme load growth. Since it is a protection system it will operate in such operational situations when the power system would break down if no protective actions were taken. Such protective actions also comprise shift of setting groups and parameter values for different protection and control devices, blocking of LTCs, switch in of shunt capacitors, etc.

*Emergency control* is associated with continuous control actions in order to save the power system, such as boosting the exciter on a synchronous generator or changing the power direction of an HVDC link.

Protection, system protection and emergency control comprise *corrective* (or curative) measures, i.e. actions are really needed to save the component or the system.

*Normal control* actions are associated with continuous control activities, that can be either step-wise, e.g. tap-changer and shunt device, or continuous, such as frequency control. Normal control is *preventive*, i.e. actions are taken to adjust the power system operational conditions to the present and near future expected situation. Normal control is usually automatic, e.g. tap-changer, reactive shunt device, frequency control and AGC.

Protection could very well be regarded as binary (on/off) emergency control, but by tradition, protection is quite specific.

*SCADA/EMS* functions are tools that assist the power system / grid operator in his effort to optimize the power system operation, with respect to economy, operational security and robustness, as well as human and material safety. Operator actions are normally (at least supposed to be) *preventive*, i.e. actions taken to adjust the power system operational conditions to the present and near future expected situation. Preventive actions, based on simple criteria, can beneficially be implemented in SCADA/EMS and be performed automatically or be suggested and then released or blocked by the operator. SCADA/EMS systems are normally too slow to capture power system dynamics.

*Optimization* is normally associated to the maximum or minimum of a mathematical (object) function, with respect to some boundary conditions. Power system optimization could therefore address optimal load-flow, i.e. minimum losses, maximum robustness against disturbances, or minimum production cost. It is however becoming more and more common, mainly among non-engineers, to call any improvement an “optimization”.

*Phasor Measurement Units* (PMU), is a device for synchronized measurement of AC voltages and currents, with a common time (angle) reference. The most common time reference is the GPS-signal, which has a precision

down to 1  $\mu$ s. In this way the AC quantities can be measured as complex values and represented by their magnitude and phase angle.

### Power System Phenomena to Counteract

Utility needs and problems are often formulated in very loose terms, such as “intelligent load shedding”, “protection system against major disturbances”, and “counteract cascaded line tripping”. These needs have to be broken down to physical phenomena, such as protection against:

- Transient angle instability (first swing)
- Small signal angle instability (damping)
- Frequency instability
- Short-term voltage instability
- Long-term voltage instability
- Cascading outages

#### *Transient angle instability*

Off-line design studies have normally been made to ensure the transient angle stability for credible contingencies. Parameters to influence during the design stage are line circuit impedance, trip time, autoreclosing, inertia constants, and additional equipment such as series capacitors and breaking resistors. In the operational stage certain power flow levels must not be exceeded. PMUs allow for direct and fast angle measurement, instead of indirect power measurement, and more accurate control algorithms for emergency control or protective actions can be designed.

#### *Small signal angle instability*

Off-line studies, such as eigenfrequency analysis and time simulations have to be done to check the damping conditions for different frequencies. SVCs in the network and power system stabilizers on the generators are common means to counteract power oscillations. Again PMUs in the power system can provide accurate angle measurements.

#### *Frequency instability*

Frequency instability is most commonly the result of a sudden, large generation deficit. Automatic underfrequency controlled load shedding is the widely used measure to counteract a system breakdown in such situations. Also the time-derivative of the frequency is used in some applications. In case of overfrequency, due to sudden loss of load, generators can be shed.

#### *Short-term voltage instability*

Short term voltage instability is normally associated with an extremely severe reduction of the network capacity, e.g. caused by the trip of several parallel lines due to a bush fire. Characteristic for the short-term voltage instability is that there is no stable equilibrium point immediately after the clearance of the initial fault(s). Remedial actions to save the system in such a situation therefore have to be fast (a few seconds or fractions of a second) and powerful (e.g. large amount of load shedding).

#### *Long-term voltage instability*

When a power system is in transition towards a “long-term voltage instability”, the power system “survived” the initial disturbance, i.e. there was a stable equilibrium point immediately after the clearance of the disturbance. However, load recovery and tap-changer operation cause the transmission system voltage to decrease and the collapse occurs in the time-scale of 10 seconds to 30 minutes. Without any initial disturbance, a long-term voltage instability might occur due to a very large and rapid load increase.

#### *Cascading outages*

Cascading outages of lines or generators might have different origins, but are mainly associated with some kind of overload, followed by trip of one line or generator unit, which cause an increased overload on the remaining units, and so on. In such situations load shedding or generation rejection might be required to preserve the integrity of the power system.

For each phenomenon a reliable (based on redundancy and robustness) protection system has to be designed, with respect to input variables, decision criteria and output actions. Parallel systems counteracting different phenomena and different layers of safety nets can be designed and coordinated.

### Normal vs. Emergency Control

The difference between *normal* and *emergency* control is the consequence for the power system if the control action is not performed. If a normal, *preventive*, control action is not performed there is an increased risk for the loss of power system stability, i.e. stability will be lost if a severe disturbance occurs. If an emergency, *corrective*, control action is not performed, the system will go unstable. The response requirements (time and reliability) are normally higher for emergency control actions than for normal control actions. Emergency control functions are almost always automatic, while normal control actions can be either automatic or manual, e.g. in conjunction with alarms. The actions taken in the power system are however quite similar for both normal control and emergency control.

#### *Voltage control*

Voltage control comprises actions like AVR, tap-changer, and shunt device, automatic or manual control. The control variable is usually the voltage level or reactive power flow. For system protection purposes or “emergency control” also load shedding and AGC can be used.

#### *Frequency control*

Primary frequency control is normally performed in the power stations by the governor controls, while secondary frequency control is performed by the AGC change of set-point or start/stop of units by the dispatcher. For emergency control, load shedding as well as actions that reduces the

voltage and hence the voltage sensitive part of the load, can be used.

#### *Power flow control*

Load level, network topology and generation dispatch are the most common parameters that influence the power flow. Automatic power flow control is performed by AGC, HVDC-control, UPFC, TCSC, phase-shift transformers, etc.

#### *Angle control*

Angle control is more or less based on PMUs. Without PMUs power flow is an indirect method of measuring and controlling the angle. The actions are similar as for power flow control.

### **Requirements on Protection Compared to SCADA/EMS**

Products for wide area protection and emergency control should be designed and manufactured in a similar way as conventional equipment protection, concerning standardization, flexibility, hardware and software modularization, configuration and functionality. Maximum benefit from available hardware that have passed different kinds of EMC and environmental tests, as well as, software functions available from other protection terminals, has to be made. Standardized communication protocols and hardware are also essential.

SCADA/EMS functions based on phasor measurements and inputs from system protection terminals should in general be compatible with present and future SCADA/EMS systems.

Based on synchronized phasor measurements, more efficient state estimation can be performed. Based on fast and reliable state estimation a variety of system stability indices can be derived and monitored on-line to the system operator. Different (faster than real-time) stability programs for a number of contingencies can then be run to evaluate risks and margins.

Different kinds of “intelligent” load shedding can be ordered more or less automatically from the SCADA/EMS system in case of energy shortage on the electricity market or other limitations in the power system operation, that can be planned in advance. With access to wide area measurements, such a system can be made adaptive to cope with the actual system conditions, such as load flow pattern and voltage levels.

To clearly distinguish between protection and SCADA/EMS also fits very well with utility and grid company organizations, where the responsibility for protection and SCADA/EMS are usually directed to different departments or divisions within the company.

### **Possible Design Architectures**

Since the requirements for a wide-area protection/optimization system can vary from one utility company to another, the architecture for such a system must be designed

according to what technologies the utility possesses at the given time. Also, to avoid becoming obsolete, the design must be chosen to fit the technology migration path that the utility in question will take. Three major design approaches are discussed below.

#### *Enhancements to SCADA/EMS*

At the other end of the spectrum, enhancements to the existing EMS/SCADA can be made. These enhancements are aimed at two key areas: information availability and information interpretation. Simply put, if the operator has all vital information at his fingertips and good analysis facilities, he can operate the grid in an efficient way. For example, with better analysis tool for voltage instability, the operator can accurately track the power margin across an interface, and thus can confidently push the limit of transfer across an interface.

SCADA/EMS system capability has greatly improved during the last years, due to improved communication facilities and highly extended data handling capability. New transducers such as the PMUs can provide time-synchronized measurements from all over the grid. Based on these measurements, improved state estimators can be derived.

Advanced algorithms and calculation programs that assist the operator can also be included in the SCADA system, such as “faster than real time simulations” to calculate power transfer margins based on contingencies.

The possibilities of extending the SCADA/EMS system with new functions tend to be limited. Therefore it might be relevant to provide new SCADA/EMS functions as “stand alone” solutions, more or less independent of the ordinary SCADA/EMS system. Such functions could be load shedding, due to lack of generation or due to market price.

#### *“Flat Architecture” with Protection Devices/Terminals*

Protection devices or terminals are traditionally used in protecting equipment (lines, transformers, etc.). Modern protection devices have sufficient computing and communications capabilities that they are capable of performing beyond the traditional functions. When connected together via communications links, these devices can process intelligent algorithms based on data collected locally or shared with other devices.

Powerful, reliable, sensitive and robust, wide area protection systems can be designed based on de-centralized, especially developed interconnected system protection terminals. These terminals are installed in substations, where actions are to be made or measurements are to be taken. Actions are preferable local, i.e. transfer trips should be avoided, to increase security. Relevant power system variable data is transferred through the communication system that ties the terminals together. Different schemes, e.g. against voltage

instability and against frequency instability, can be implemented in the same hardware.

Different layers of protection can be used, compare with the different zones of a distance protection. The voltage is for example measured in eight 400 kV nodes in a protection system against voltage instability. In a certain node is a certain action taken if:

- 6 of the 8 voltages are low (e.g. <380 kV), or
- 4 of the 8 voltages are very low (e.g. <370 kV), or
- the local voltage is extremely low (e.g. <360 kV).

Using the communication system, between the terminals, a very sensitive system can be design. If the communication is partially or totally lost, actions can still be taken based on local criteria. Different load shedding steps, that take the power system response into account – in order not to overshoot, can easily be designed.

Protection systems against voltage instability can use simple binary signals such as “low voltage” or more advanced indicators such as power transfer margins based on the VIP-algorithm [3], or modal analysis.

The solution with interconnected system protection terminals for future transmission system applications is illustrated in Figure 1 for protection against voltage instability; similar illustration can be done for angular instability.

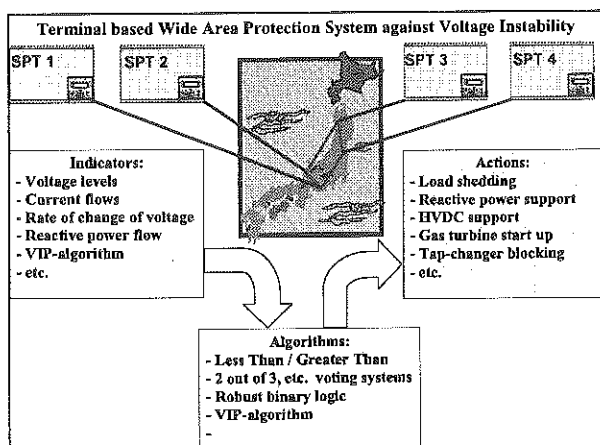


Figure 1. Terminal based wide area protection system against voltage instability.

More details about the “flat architecture” are given in a companion paper [4].

#### Multilayered architecture

While the above two designs attempt at extending the “reach” of existing control domains (protection terminal being one domain, and EMS being the other), there is no guarantee that the end solution will be comprehensive. A comprehensive solution is one that integrates the two

control domains, protection devices and EMS. Such a solution is depicted in Figure 2.

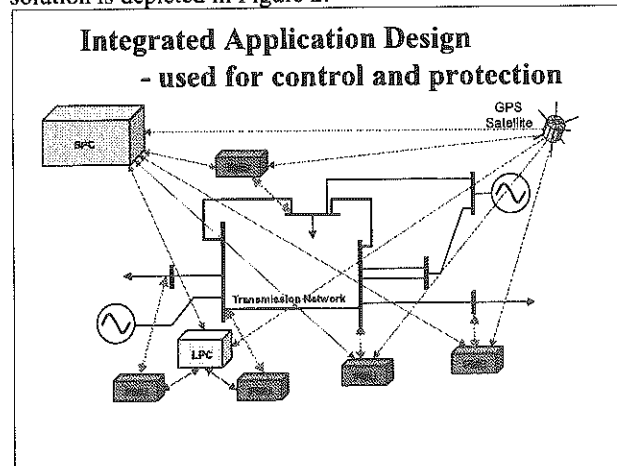


Figure 2. Multilayered wide area protection architecture.

There are up to three layers in this architecture. The bottom layer is made up of PMUs, or PMUs with additional protection functionality. The next layer up consists of several Local Protection Centers (LPCs), each of which interfaces directly with a number of PMUs. The top layer, System Protection Center (SPC), acts as the coordinator for the LPCs.

Designing the three-layered architecture can take place in several steps. The first step should aim at achieving the monitoring capability, e.g., a WAMS. Wide Area Measurement Systems (WAMS) is the most common application based on Phasor Measurement Units. These systems are most frequent in North America, but are emerging all around the world. The main purpose is to improve state estimation, post fault analysis, and operator information. In WAMS applications a number of PMUs are connected to a data concentrator, which basically is a mass storage, accessible from the control center, according to Figure 3.

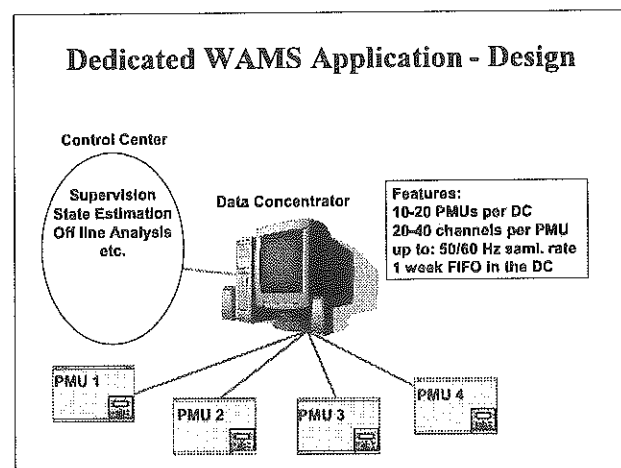


Figure 3. WAMS design.

Starting from a WAMS design, a data concentrator can be turned into a hub-based *Local Protection Center* (LPC) by implementing control and protection functions in the data concentrator, Figure 4.

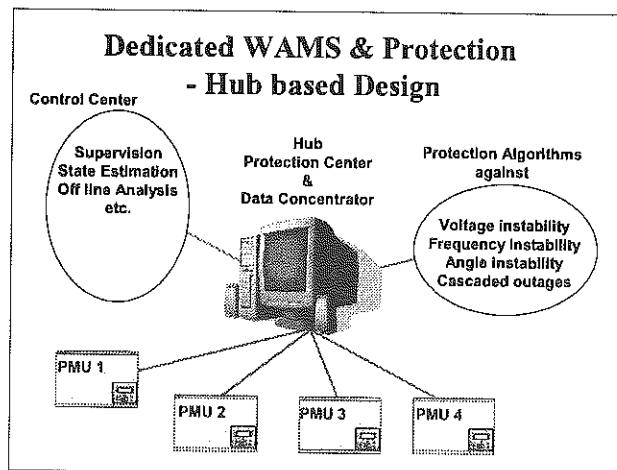


Figure 4. Hub based wide area protection design.

A number of such local protection centers can then be integrated into a larger system wide solution with a *System Protection Center* (SPC) at the top, see Figure 2. With this solution the local protection center forms a system protection scheme (SPS), while the interconnected coordinated system forms a defense plan [5]. A companion paper [6] provides more details.

### Institutional trends

As the electricity market is restructured all around the world, the nature of utility companies is changed. In particular, the downsizing of the staff makes it difficult or impossible for the utility company to perform many R&D functions. As a result, there is a trend in the industry where utility companies collaborate with vendors to cope with issues related to the grid. The utility company can view its partnering vendor as a substitute for its vanishing R&D department to perform tasks that its existing staff cannot handle. The vendor sees the partnering utility as the "sounding board" for its product development and the place to demonstrate its latest products. This closed-loop collaboration, which already exists in the form of pilot projects in wide-area protection/optimization, is found to be fruitful to both parties.

### Discussion

The meaning of wide area protection, emergency control and power system optimization, may vary dependant on people, utility and part of the world, although the basic phenomena are the same. Therefore standardized and accepted terminology is important.

The solution to counteract the same physical phenomenon might vary extensively for different applications and utility conditions. A certain utility might wish to introduce a complete system to take care of a large number of applications in one shot, while others want to move very slowly with small installations of new technology in parallel with present systems. Some utilities want to do large amount of the studies, design and engineering themselves, while others want to buy complete turn-key systems. It is important for any vendor in this area to supply solutions that fit with different utility organizations and traditions.

The potential, to improve power system performance using smart control instead of high voltage equipment installations, seems to be great.

### Conclusions

This paper has discussed terminology, phenomena and solution implementation strategies for wide area protection. It is concluded that different applications will require different solutions. Therefore system design and equipment must be very flexible both in size and complexity.

The introduction of the Phasor Measurement Unit (PMU) has greatly improved the observability of the power system dynamics. Based on PMUs different kinds of wide area protection, emergency control and optimization systems can be designed.

A great deal of engineering, such as power system studies, configuration and parameter settings, is required since every wide area protection installation is unique. A cost effective solution could be based on standard products and standard system designs.

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## Wide Area Protection and Online Stability Assessment based on Phasor Measurements

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**Abstract--** A new wide area protection system based on online stability assessment increases the flexible utilization and reliability of power transmission networks. This paper discusses a wide area protection system, which complements classical protection systems and SCADA/EMS applications. System wide installed phasor measurement units send their measurement data to a system protection center, where snapshots of the transient system status are online available. This new quality of system information opens up a wide range of new applications to assess and actively remain system's stability in case of voltage or angle instability and oscillations. A new voltage stability prediction algorithm for transient system states and cascaded contingencies is introduced. The applicability of the algorithm is shown with the example of a test system and a real power system.

**Index Terms --** Voltage Stability, Stability Prediction, Phasor Measurement Units, Wide Area Protection

### I. INTRODUCTION

Wide area protection is still an important topic since system wide collapses occur frequently in many power systems [1]. Since several years much effort has taken to indicate voltage stability [2]. The proposed indicators are designed for the implementation in control centers and base on SCADA data. Two major kinds of indicators can be distinguished. The first ones are the sensitivity-based indicators, like [3] or the minimum singular value of the load flow Jacobian [4]. This kind of indicators only considers the actual state of the system and does not predict any influence by discontinuous elements like reactive power limiters or under load tap changing transformers. The second ones are all types of power resp. stability margin calculations in the sense of calculating the difference between the actual system's state and a point on the stability boundary. The continuation power flow [5],[6] is the best-known algorithm for this application. All discontinuous and steady-state effects influencing voltage stability are modeled.

However, the nowadays application of all these approaches has the drawback that the basic SCADA data assumes that the system is in a steady-state equilibrium. For slow changes in the system, like changes of the load over day, this assumption is sufficient. However, a typical voltage collapse mostly occurs after cascaded contingencies or faults, which lead to an unstable system's state. This unstable state is a dynamic transient process of several seconds up to tens of minutes, which makes

the voltage stability problem hard to handle with the nowadays steady-state approaches. In spite of a well theoretical knowledge [7] there are no practical realizations considering the system dynamics for voltage stability assessment.

Pre-calculations of the stability for one or a combination of two contingency events address a part of the problem. This needs a huge calculation effort and the system's state for which a case is calculated must fit most exactly to the actual system's state. For unexpected contingency cases this approach is not useful.

Conclusively, the major drawbacks of all these approaches lie in the not appropriate steady-state system view. The solution for this is a departure from the SCADA-based approach to a transient measurement system. Such a measurement system together with the voltage stability assessment and stabilization algorithms will be called wide area protection system in the following.

Phasor measurement units (PMU), which are well known since several years [8], build the technical base for the wide area protection system. They offer phasors of voltage and currents together with a satellite triggered time stamp in time intervals down to 20 ms. Single installations of such units are in an experimental stage at many utilities [9]. Also voltage stability indicators are proposed on phasor measurements for continuous changes of power systems [10]. This paper concentrates on the stability prediction after cascaded outages. The proposed algorithms are designed especially for the opportunities that are offered by the transient system's view.

After the description of the wide area protection system setup, a transient state prediction algorithm will be introduced the first time for voltage stability applications after cascaded contingencies. The applicability of this algorithm will be shown with the example of a simplified test system and a real South American system.

### II. SETUP OF THE WIDE AREA PROTECTION SYSTEM

#### A. Hardware system setup

The PMUs must be installed throughout a critical area of the system. Critical area of the system e.g. in the sense of voltage stability means to look on critical paths from generation to load areas or dedicated transmission corridors. This critical area is the result from a system assessment, e.g. with the help



of model analysis [11] together with critical contingency screening algorithms. For such a critical area an internal model with appropriate neighbouring models at the boundaries must be formulated.

PMUs with several input channels are able to measure the voltage at a substation and all currents at the feeders and lines. The measured data is transmitted from the PMUs to a central system protection center (SPC) where the evaluation algorithms are running. The PMUs are placed to make the critical area completely observable. Together with network data, the information of neighbouring stations can be calculated. Therefore PMUs at only about each fourth station of the critical area must be installed. The optimal placement of PMUs can be done for example with the algorithm described in [12]. The communication between PMUs and the system protection center can be realized via satellite, fiber optics or other permanent available communication channels. Because of the time stamped information, snapshots of the system show all transients and dynamics of the system. Fig. 1 shows the general system setup. The structure of the system protection center is explained in the following.

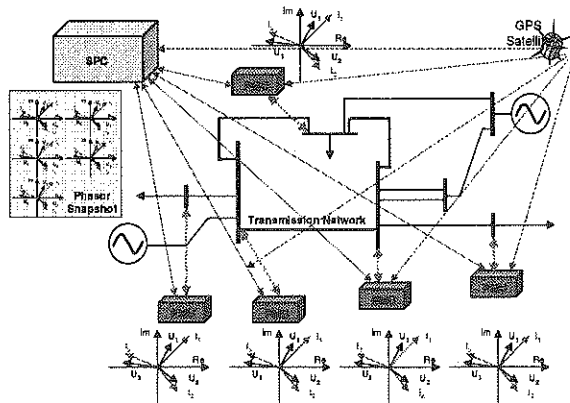


Fig. 1. Setup of the wide area protection system

### B. System Protection Center Setup

The incoming data from the PMUs must be preprocessed and arranged in a database structure. The system model for the actual situation is generated via state calculation considering the actual topology. On this base the stability status in terms of the power margin (PM) of the critical area is determined. Optimized stabilizing actions (SA) are generated accordingly.

To let the system protection center operate in real time, it receives information in the following form:

- cyclic data: snapshot of the power system in predefined time intervals (20 - 250 ms).
- event triggered resp. contingency driven data: containing update of the network topology according to contingencies.

In order to deliver a result both in normal steady-state and contingency operations the functional structure of the system protection center has been designed as depicted in Fig. 2.

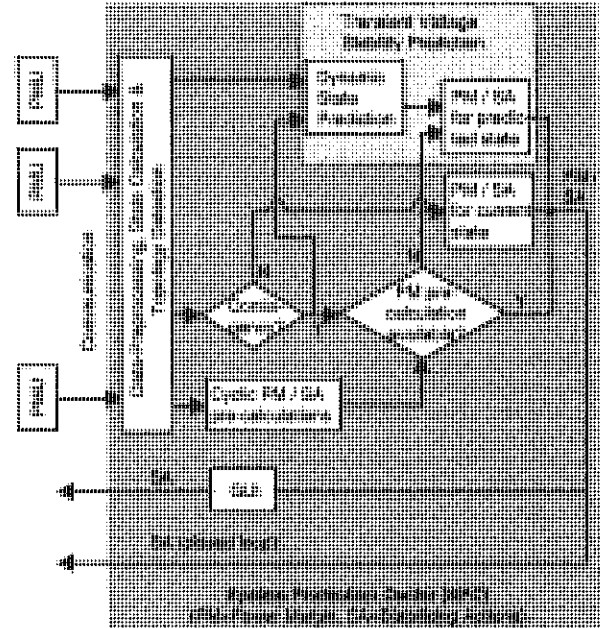


Fig. 2. Setup of System Protection Center (SPC) with embedded algorithm for transient voltage stability prediction

As long as no contingency has been detected and the power system is in a steady state, the power margin is calculated all the time for the snapshots of the power system supplied with the cyclic data. The power margin is computed by the continuation power flow (CPF). On this model stabilizing actions are calculated if the available power margin is too low.

To be prepared against the most critical contingencies in the sense of (N-1), a cyclic pre-calculation of the power margin and stabilizing actions is carried out. This is performed for all contingencies in a contingency list for an actual power system snapshot. Thus power margins and stabilizing actions for all probably worst contingencies which can occur in the current system's state are already prepared. When the calculation for the whole contingency list is finished, the next snapshot is processed the same way.

If a contingency occurs, either pre-calculated results are taken or the transient voltage stability prediction is triggered. The transient voltage stability prediction needs no pre-processed information, therefore it can follow any contingencies also cascaded ones. Whereas the power margin calculation on an actual system state and the pre-calculation is more or less standard, the transient voltage stability prediction is new and utilizes the capabilities of the dynamic system view of the wide area protection system. It will be presented and explained in detail in the following section.

The results of the power margin and stabilizing action calculations are displayed on a GUI. The stabilizing actions can be taken automatically in a closed loop if desired.

### III. TRANSIENT VOLTAGE STABILITY PREDICTION

#### A. Idea

Even if the power system is stable after a contingency, a transient phase takes place, which brings the power system to a stable equilibrium. Right after the contingency it is not possible to decide with classical steady-state based stability indicators if the system state trajectory will end in a stable equilibrium or a collapse.

The elements of the power system which cause this delay of the collapse are under load tap changing transformers (ULTC), reactive power limiters of power units with temporary overload characteristic and dynamic loads with a load recovery characteristic after voltage drops [13][14]. If conventional voltage stability indicators are applied to the power system in such a transient phase, the results are faulty or the voltage instability is detected too late, because the actual load is not the load, which is demanded seconds later. Also it will not be detected if power units are in reactive power overload or if ULTCs are in a stable tapping position.

Therefore the transient voltage stability prediction is invented to assess the voltage stability correctly after contingencies during the transient phase.

The idea of the method is to make a prediction from the beginning of the transient phase into the future until the steady-state operation point is reached. For this steady state operation point the stability can be determined by calculating the power margin. If no steady-state operation point is available the system will run into a collapse. The presented approach maps the actual measured system's status right after a contingency on an expected equilibrium point in the near future.

To determine the steady-state equilibrium of the full dynamic system model (1) it can be reduced.  $G$  are the power flow equations with  $z$  the bus voltage magnitudes and angles.  $F$  are the remaining equations with  $x$  the remaining state variables.

$$\begin{aligned}\dot{x} &= F(x, z) \\ 0 &= G(x, z)\end{aligned}\quad (1)$$

At first all short-term transients in the model are neglected. ULTC, voltage controllers, reactive power limiters and load characteristics can be transformed into their steady-state behaviour. To find the equilibrium of the remaining equation system (2) no dynamic simulations are necessary. This is due to the fact that only the existence of the equilibrium is important and not the time when it is reached. In (2)  $F_s$  are the simplified equations with the reduced state vector  $x_s$ .

$$\begin{aligned}0 &= F_s(x_s, z) \\ 0 &= G(x_s, z)\end{aligned}\quad (2)$$

With a Newton-Raphson algorithm the equilibrium of the simplified system can be determined effectively. This corresponds to a power flow with embedded additional steady-state models. With this model simplification the transient characteristics

are separated from the interesting steady-state ones. Whereas for most of the models their behaviour resp. their parameters are well determined, the parameters of the load model change during days and seasons. Therefore after a contingency the load parameters must be determined at first before the equilibrium is calculated. The determination of the load parameters is described in detail in the next subsection.

The predicted equilibrium itself represents the system with the loads after their recovery together with the voltage magnitudes and angles, the final tap changer positions and the injected active and reactive power. If a stable equilibrium is found, the power margin or other indicators can be calculated, because the conditions of a steady-state situation are fulfilled after the prediction process.

The advantage of the whole process is, that the stability can be indicated directly after the contingency during the transient phase. If no equilibrium can be found, this model can be used to determine stabilizing actions, which bring this model and therefore the real system back to a stable operation point. The time between the early detection of an instability, seconds after the contingency, and the occurrence of the expected voltage collapse can be used to take these actions. Possible actions are load shedding, blocking of ULTC-tapping, activation of reactive power, change of voltage set-points of voltage controlling devices (FACTS-devices, ULTC, secondary voltage control, etc.), Automatic Generation Control (AGC), or controlled islanding.

#### B. Description of the Algorithm

The algorithm has four steps. A flow chart is shown in Fig. 3:

① While the system is running in a steady-state situation the steady-state values of bus voltages  $V_0$  and load powers  $P_0$  and  $Q_0$  must be traced and contingencies as changes in the topology must be detected.

② The parameters of a dynamic load model, which describe the voltage dependency of the power, are determined. For this a sliding window of values of voltage  $V$  and load  $P, Q$  at each bus is evaluated. These values are the output of the state calculation in the SPC.

③ The determined load parameters together with the base loads  $P_0, Q_0$  and voltage  $V_0$  are fed into a power flow calculation considering also under load tap changers and power margins of devices. This power flow model represents exactly the steady-state behaviour of the completely modeled dynamical system. The convergence of the power flow leads to the steady state solution resp. to the equilibrium point of the dynamic system. This equilibrium point is the predicted state of the system, which might be tens of seconds in the future. If the power flow does not converge and no equilibrium is found the transient phase will end up with a collapse.

④ If the power flow converges the power margin is calculated with the continuation power flow.

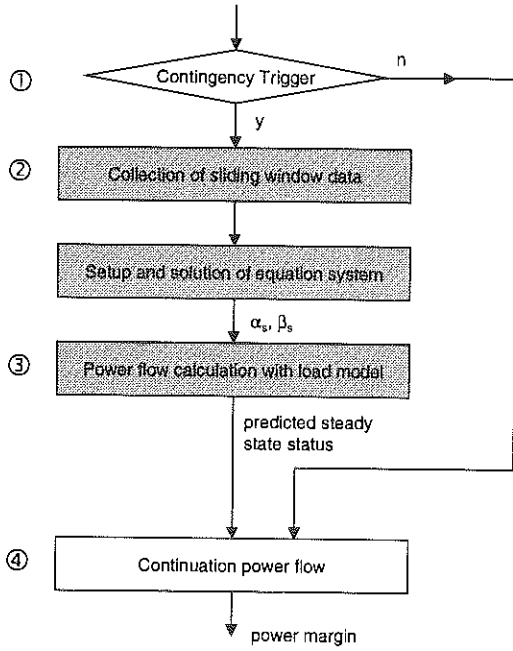


Fig. 3. Flowchart of state prediction algorithm

The system set-up traces continuously the state values of the system like voltages, currents and active and reactive power. From the current measurement at the minimum at one end of a line, the outage of the line is detected (Step ①). After that a sliding window of measured bus voltages and feeder loads is collected (Step ②). In the following the assumed load model, which has to be adapted to the voltage and power measurements, is the Hill and Karlsson Model [15] in the state space form in equations (3) and (4). This is a well-known standard model for voltage stability cases. But also any other model, like e.g. composite ones, can be used.

$$T_p \dot{x}_p = P_0 \left( \frac{V}{V_0} \right)^{\alpha_s} - \left[ x_p + P_0 \left( \frac{V}{V_0} \right)^{\alpha_u} \right] \quad (3)$$

$$P = x_p + P_0 \left( \frac{V}{V_0} \right)^{\alpha_u} \quad (4)$$

To determine the load parameters two approaches a non-linear and a simplified linear one are presented in the following.

#### 1) Non-linear determination of load parameters

The equations (3) and (4) can be reformulated as eq. 5.

$$-T_p \dot{P} + P_0 \left( \frac{V}{V_0} \right)^{\alpha_s} + \frac{P_0}{V_0} \dot{V} T_p \alpha_u \left( \frac{V}{V_0} \right)^{\alpha_u-1} = P \quad (5)$$

This equation has the unknown parameters  $\alpha_s$ ,  $\alpha_u$ , and  $T_p$ . For measurement points from the sliding window the values for  $V$ ,  $P$ ,  $\dot{V}$ ,  $\dot{P}$  can be determined.  $\dot{P}$  and  $\dot{V}$  are the mean values of the gradients to the two timely neighbouring meas-

urement points. For more than three time steps an over-determined non-linear equation system is given which can be solved with a solver algorithm (e.g. Nelder-Mead-Algorithm). Such an algorithm needs a suggestion ( $\alpha_{s,0}$ ,  $\alpha_{u,0}$ ) for the starting point of the unknowns. These values can be taken from the last available calculation. For the first time a good estimation with standard values must be taken.

#### 2) Linear determination of load parameters

To get rid of the start values and speed up the calculation time, a transformation of the above equation into a linear equation can be done:

$$-x_1 \dot{P} + P_0 x_2 + \frac{P_0}{V_0} \dot{V} x_3 = P \quad (6)$$

The interesting variable for the steady state behaviour is  $\alpha_s$ . This value is determined by:

$$x_2 = \left( \frac{\bar{V}}{V_0} \right)^{\alpha_s} \quad (7)$$

$\bar{V}$  is the mean value of the voltage in the sliding window. This transformation is an approximation, which is only valid for small changes of  $V$  during the time interval of the sliding window. Therefore the error for the determination of the variables is getting more accurate over time after the event.

The according over-determined linear equation system is given by:

$$A \cdot x = b \quad \text{with}$$

$$A = \begin{bmatrix} -\dot{P}(t_1) & P_0 & \frac{P_0}{V_0} \dot{V}(t_1) \\ -\dot{P}(t_2) & P_0 & \frac{P_0}{V_0} \dot{V}(t_2) \\ -\dot{P}(t_3) & P_0 & \frac{P_0}{V_0} \dot{V}(t_3) \\ \dots & \dots & \dots \\ -\dot{P}(t_n) & P_0 & \frac{P_0}{V_0} \dot{V}(t_n) \end{bmatrix} \quad b = \begin{bmatrix} P(t_1) \\ P(t_2) \\ P(t_3) \\ \dots \\ P(t_n) \end{bmatrix} \quad (8)$$

To solve this system a least squares approach is used according to:

$$(A \cdot x - b)^2 = \text{Min} \Rightarrow x = (A^T A)^{-1} A^T b \quad (9)$$

Both approaches, the non-linear and the linear, have to be applied also for the reactive power with measurements of  $Q$  and  $\dot{Q}$ .

#### 3) Comparison of the approaches

The selection of the two approaches is determined by the available calculation time in the system protection center. The algorithm must be calculated for each feeder resp. sum of

feeders of a substation to determine the behaviour of all loads in the system. If it can be seen that the loads behave the same in a certain area of the system, the number of calculations can be reduced to single examples for each area.

The linear approach is more robust than the non-linear one, because the non-linear algorithm needs iterative solver algorithm, which probably runs to a not desired local solution. In comparison to that the higher accuracy of the non-linear must be considered. In the following examples the non-linear approach operates well. But the starting values for the unknown variables are known. It must be shown in practice if the same results can be reached with more inaccurate starting values.

#### IV. SIMULATION EXAMPLES

##### A. Simplified test system

A simplified test system (Fig. 4) is used to test the algorithm. The observed load is connected behind an under load tap changer. After the tripping of one of the double lines the voltages of the load busses are decreased. Therefore the load is also decreased and the system is stabilized in the first seconds after the contingency. In the following the under load tap changer tries to restore the voltage at the load bus.

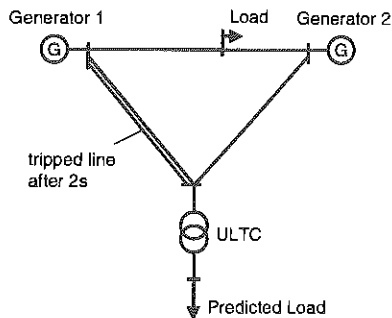


Fig. 4. 6-bus test system

After the line tripping at  $t = 2s$  some short-term oscillations in the system occur. After the event the sliding window starts with 20 measurement values with a time distance of 250ms. Therefore the total length of the window is 5s. The determined variables  $\alpha_s$  for active and  $\beta_s$  for the reactive power are shown for both algorithms in Fig. 5.

The sliding window contains at the beginning the oscillations after the contingency. This results in inaccurate values up to about 8s after the event, mainly for the linear algorithm. The non-linear algorithm is more robust. Also the larger deviation of voltage after the contingency causes a larger error for the linear algorithm because of the assumptions in this algorithm. The error of the linear algorithm results in larger values for  $\alpha_s$  and  $\beta_s$  than expected. This would also lead to larger power margins. Therefore this prevents misbehaviour of triggering stabilizing actions too early.

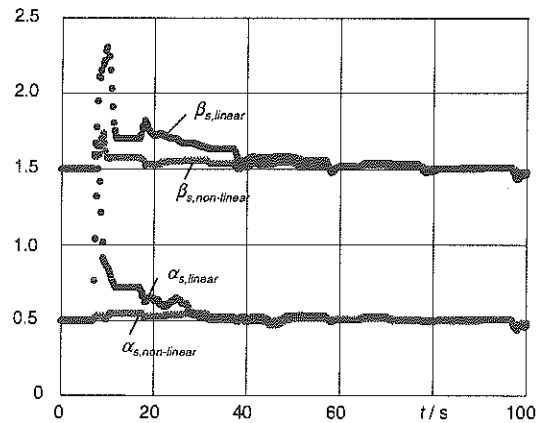


Fig. 5. Estimated load parameters

The results from the parameter estimation for the load model are fed into the calculation of the predicted equilibrium. Based on the predicted equilibrium the power margin is calculated. The results for the test system are shown in Fig. 6 in comparison to a non-predictive power margin calculation.

The power margin  $PM$  is calculated with an increase of all loads in the system while the load pattern is fixed until the collapse point is reached.  $PM$  is the possible load increase as percentage of a base load situation. The non-predictive case assumes a steady-state situation at each time step. For the prediction the non-linear algorithm is used.

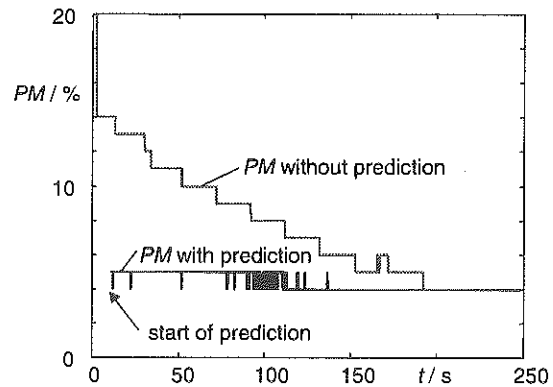


Fig. 6. Power margin  $PM$  as percentage of the base load  $P_0$

The effect of the prediction can be seen clearly. Only 170 s after the event, the power margin without prediction hits the predicted one.

##### B. Real power system example

The example of the real power system is based on the network data of a real South American system. This example demonstrates the applicability of the approach to a real system. The single line diagram is shown in Fig. 7. The system is characterized by a large load area in the center of the system and generation areas about 400 km in the north and south

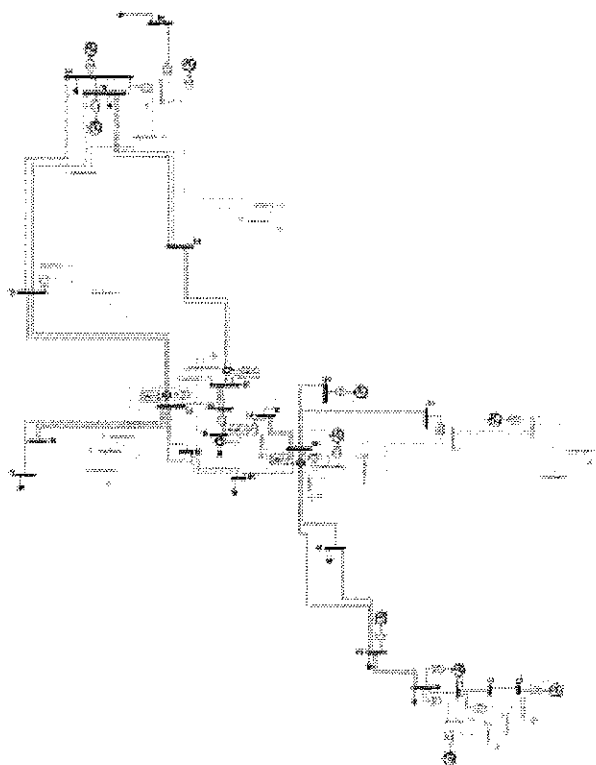


Fig. 7. Single line diagram of a real South American power system

The contingency situation for the simulation is a cascaded outage of two lines between the load center in the middle of the system and the northern generation area at 2s resp. 20s. These contingencies lead to a critical situation nearby the stability boundary but not to a collapse. Fig. 8 shows the predicted load parameters. The results are according to the simplified test system.

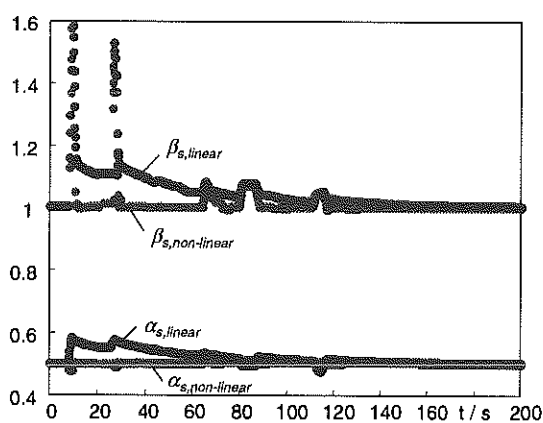


Fig. 8. Estimated load parameters

Fig. 9 shows the power margin  $PM$  for the predicted and the non-predicted case. The results are not so impressive as in the simplified system, because the voltage sensitivity is lower,

which reduces the effect. This can also be seen after the first contingency where the system is still stable. The higher accuracy resulting from the prediction is only 1 %. After the second contingency the effect is stronger. From the beginning of the prediction after the second contingency the proposed algorithm leads to a forecast of about 50 s until the predicted and the non-predicted  $PM$  are the same. Therefore the scope for stabilizing actions is extended by this time interval.

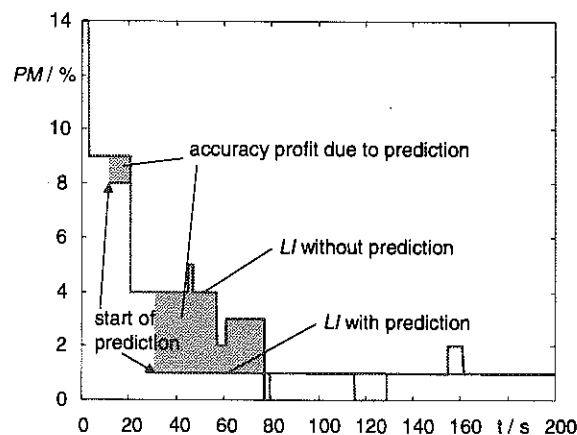


Fig. 9. Power margin  $PM$  as percentage of the base load  $P_0$

## V. REACTION ON DIFFERENT CONTINGENCIES

Up to this point only line trippings are considered as contingencies. Other contingencies would be generator or load feeder trippings.

A generator tripping is detected directly by the PMU measurement. This would result in decreasing voltages because of the loss of reactive power. Therefore the described algorithm can be applied without any changes.

Changes of the loads are normally a progress of several minutes if take a look only on the highest voltage level which is decisive for voltage stability. This has to be considered by the permanent update of the base values  $P_0$ ,  $Q_0$  and  $V_0$ . Immediate changes in the load power can be caused by feeder openings. This is detected directly by the PMU. The values  $P_0$  and  $Q_0$  must be changed in this moment if they are calculated as the sum of several load feeders in one substation including the tripped one. But in this case the feeder opening would stabilize the system anyway. The closing of a load feeder is only possible if the calculated power margin allows this.

The described algorithm covers all kinds of contingencies without any changes. The contingencies in this case are topology changes as line or transformer outages resp. generation outages. But the algorithm to determine the kind of contingency and triggering the transient voltage stability prediction and the following continuation power flow has to consider all these cases.

## VI. CONCLUSIONS

This paper introduces a wide area protection system for voltage stability. On the base of phasor-measurements a critical area of a power system is observed. Dynamic snapshots of the system's state are provided in a system protection center in short time intervals. These data are used by the protection algorithms, which determine the stability of the system and propose stabilizing actions.

Beside the stability calculation for steady-state situations and pre-calculations of contingency cases, the system targets mainly on the stability prediction after cascaded contingencies. The proposed process considers the system's dynamics in the long-term transient phase, which is typical for voltage collapses. The proposed algorithm determines in a time interval of 10 s after a contingency if the following dynamics will lead to a collapse. In comparison, nowadays approaches would determine the proper stability value tens of seconds up to minutes later, because they assume the long-term dynamics as steady-state. Both the time interval from the prediction to the predicted state in the future and the accurate knowledge about the situation in which the system will run makes it possible to determine and take optimized stabilizing actions. The determination of the stabilizing actions is in progress and not part of this paper.

The proposed approach works for slow voltage instabilities. If contingencies occur in quick succession, estimates for the load parameters must be taken, because the algorithm can not follow. If the system is stressed so heavily, that the voltage decreases rapidly, actions like under voltage triggered load shedding must be taken immediately to protect the system. The coordination of these measures and also the classical protection schemes with the wide area protection system is one task for the practical application.

The integration of angle stability and oscillatory problems will be the next step to use the advanced opportunities of the presented PMU based wide area protection system.

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## VIII. BIOGRAPHIES



**Christian Rehtanz** was born in Germany in 1968. He received his diploma degree in Electrical Engineering in 1994 and his Ph.D. in 1997 at the University of Dortmund, Germany. He is now with ABB Corporate Research Ltd., Baden, Switzerland. His research activities include the stability assessment, wide area protection and integrated control of advanced power systems, information technology applications and questions of distributed power generation.

## Discussions on Session II: PROTECTION

### Part 1

**P. Sauer** (University of Illinois): I have detected a lot of similar ideas in these papers. It is very interesting, and it makes a person wonder what we should be doing. In the past and even today, we have incredible capability of substations to gather data and even to get that data to an EMS on a wide area or regional basis. Yet there is quite a hesitation on the part of most operators to do anything with that data. Not that they wouldn't do it if they could, but most people don't know what to do with the data. There seems to be a big gap between having the data and knowing what to do with it. Now I would think that in terms of what A. Phadke was talking about in the relay trip. Given you had all this data on the regional bases, you probably would know what to do. You could make a decision, say, open that line and only that line, everybody else do nothing. Those types of decisions seem to be doable, or at least you can program that on the regional basis. The tougher ones are the stability ones in the wide area controls. Even if you had all the information and all the buses, you still wouldn't necessarily know what to do to prevent anything bad. So I guess I'll just ask four of you what is holding up the progress in real time control in a wide area basis if you had all the information, and you can do instantaneous computing. Do we know what we would do with it? Is the theory there for the control? Or, there is still a big gap in that?

**A. G. Phadke:** My answer is easier because Pete sort of gave it to me. The protection decisions are a little bit straightforward if you could bring the data in. You don't need to bring it throughout the power system. The kind of issue I discussed is the hidden failures. Those decisions for a given location are made and can be made from data from maybe 6 or 7 substations nearby. I think if the incidents of a catastrophic failure increase, or if there are more misoperations of protection, we will begin to see coming to play right away. In fact, about the kind of system that I show you on control dependability and security, at least one system already exists. So I think as people perceive the need, this could be done. That's the protection side. Maybe the other ones would say something about the control side.

**C. Rehtanz:** Utilities told us that combination of, for example, load shedding with an islanding scheme that the moment the system is separated into different islands, they do not want to wait for any automatic load shedding based on the frequency relay. If they would know in the moment of islanding, which also can be optimized with a system approach in the moment, then they directly know how many loads have to be shed, when and where, would be a great advantage. We can

go through all sorts of conventional applications, which have to be included as a bottom layer. Also do not rely on only such a wide area protection system. If we go through these different available applications and look at what we can improve, we will find several things such as the example I have given.

**D. Karlsson:** Utilities are moving quite slowly. If we look at large utilities, such as Hydro-Quebec and EDF, they have been practicing wide area protection for a long time, and they have a large staff of engineers to work with this. Today the utilities are very much focused on power business, and not so much on grid operation. They are downsizing, but they also realize that you can make some money if you can increase power transfer. At this stage, there is great interest from many medium sized power companies for solutions that can help them use their installed capacity in a more efficient way without reducing the reliability.

**M. Begovic:** I would like to say a few words about Pete's initial comment. The technology behind wide area measurement protection has been around for a number of years. That, in some way, has presented a drawback because many utilities that have expressed initial interests in such devices have acquired equipment that provides a large amount of unprocessed data. That has frustrated some of the utility users, because of the lack of applications for such devices. They ended up having hundreds of thousand dollar measurements of phase angles along the lines. That is beginning to change, and important factors are standardization of devices, lower cost of implementation, and, above all, application development. I believe that most of the analytical techniques necessary for a large number of applications are either developed or fully implementable. But it will take time for manufacturers to develop such applications and offer standardized equipment.

**T. Van Cutsem** (University of Liege): In at least two of the presentations, we have seen systems that try to identify the parameter of either the load or equivalent of the system. Could you tell us a little more about the later achievement in terms of how much time it takes to reach reasonably accurate values of the parameter, and what about the influence of what's going on in the system at the same time? Maybe the parameters are changed continuously because of actions taken in the system by the emergency control scheme, similarly for your model with load restoration. This makes the system time varying, and can change very fast in this period of time when you identify the parameter. Could you elaborate on this?

**M. Begovic:** The relay that I have described is very fast. It is not meant to predict and identify the changes in the system topology in any other way than by the local measurements. If nothing happens in the outside system, it can not even predict the external equivalent. However, any changes in the outside system are immediately inputting the equivalent and effects that can be implemented instantaneously. However, this is not a system-wide tool, it is still based on localized measurements, and its accuracy can not be compared with that of a full system-wide tool. Therefore, it should be taken as an intermediate step between the conventional non-adapted protection. I have always likened this relay to an adaptive under-voltage relay, because of the importance it has. So it's an intermediate step that provides very fast calculations, but it's not a full system-wide solution that can take into account all changes in the system.

**C. Rehtanz:** We will need a time window of information where the system doesn't change for about five seconds. Therefore, within these five seconds, we need little change in the system. But if there is another event, then we have to start again until the earlier five-second window is available. It means that we can use this approach only for slow voltage instability. If the requirements are not fulfilled and we can not calculate it and make prediction, then we can directly use the data, and use for the parameters directly some given values from the last event, or make some assumptions.

**L. Fink:** I have a tendency to listen to every presentation and ask myself how this is affected by the ongoing restructuring of the industry. When we talk about protective systems in general and special protective schemes in particular, I recall the resistance there has been to adoption of this device because of fear of misoperation. I am wondering how the splitting up of the industry with proliferation of independent power producers rather than vertically integrated utility is going to affect the ability of the network company to install such a scheme.

**C. Rehtanz:** For transmission systems operators, there is pressure to operate the system close to the stability boundary. The operators can stretch the system a little bit more and increase the risk but he has to calculate the risk or the profit from the risk to increase the loading level on the line, and has to compare with the risk and price of actions. He has come to a point that such a system with relatively low investment could be the better solution than building the new line. Therefore, there is also an appropriate tool in the restructured market. There is a problem when the system goes down and they have a load shedding scheme and want to improve these things only as a first step without major investment in the new power stations and lines.

**D. Karlsson:** In an area where utilities are splitting up, we have a network company in many cases. These network companies face pressure to utilize the grid more efficiently. I think that all practices now agree that this type of wide area protection can help to use the grid more efficiently. So there is also motivation to install this equipment. On the other side, there are so many practices involved, because the grid operators do not own the lines, the agency has to have some agreement with the owners. He doesn't control the load and he has to have some agreement or legal authority to affect the load so there will be many legal practices in such a system. So it's more complicated.

**C. Vournas** (National Technical University of Athens): My question is to C. Rehtanz. I really can not see the difference you obtained by having the phasor measurements in slow voltage stability. The same prediction you could do with the SCADA data (the present state of the system). Having the correct models for lines and generators you can predict whether your system is stable or unstable under any given contingency. This is a standard VSA level of EMS. I know the effect of phasor measurements when you want to predict transient stability, but for slow voltage stability is a little bit too much, I think.

**C. Rehtanz:** It is a very modest and interesting point. The difference of what we are using here is the time frame of the data. SCADA data in modern systems are acquired about every ten seconds, then we have the data updated about ten seconds. Within the ten seconds, some data can be from the beginning of the interval with other data at the end of interval. Therefore, we have not appropriate accuracy to perform such calculations. To apply this calculation on a stable system would mean to wait for several data items to come from the SCADA systems, several data points with maximum intervals of about ten seconds, and then we need one minute or two to perform the same calculation. We can make this calculation within five seconds and use the time for taking actions. On the other hand, if we look at the SCADA system, SCADA systems are improved, and I'm absolutely sure that this part of applications and the phasor measurement will be part of the SCADA system in the future. The data access into the SCADA system will change. In the future SCADA system, we can make the same system snapshot, where all data fit together with time information in the next generation of SCADA systems. Therefore, this application and most parts of wide area protection based on phasor measurements unit will be integrated into SCADA system in the future. But nowadays, it is not reasoned to integrate this system into given SCADA system because of too many faults. Therefore, we build as an old product and then we have also the higher reliability with different systems running in parallel.

**D. J. Hill** (University of Sydney): I have a question for



**C. Rehtanz:** Could you just comment on the voltage level you're dealing with? Is there any special difficulty that you have to have overcome?

**C. Rehtanz:** The system is for the higher voltage levels, and therefore, we look into load feeders to a lowest system level. We find there is a voltage dependency that we have to determine. We are not going into the deepest level of the load from the 10 kV feeders, but here the system was 345 kV and 220 kV, and then looking down into, maybe 110 or 132 kV level in that system and model the loads. All the loads are lumped together within this model. Therefore, with principal approach, if we found that its load model is not appropriate, we need another one. The basic algorithm is free to implement another load model where we can set up an equation system for another load model to find the parameters. From the technical side, there is essentially no problem.

**R. Schlueter** (Michigan State University): I have a question for Dr. Rehtanz. I would have guessed that tap changers at a low voltage level would all play a role in this load model development, but your results would suggest 5 seconds you're capturing perhaps only one, is that correct? That is dominant, and if that is not dominant, you take on a more complex problem. Or, longer time interval?

**C. Rehtanz:** From the view of higher voltage levels, we see somewhere down the system a lot of under-load tap changers. Therefore, all of them together we have given a part of this transient rate. If it is not appropriate and if we need to include all of them and make a model then we run out of the calculation time so we will kill the procedure. So far as we live on the highest voltage level, and look into the system and several things that are going on there. We assume at first that is appropriate.

**D. Koval:** One other question I want to ask is, you're talking about load shedding, right? What bothers me is, in most systems when you do load shedding, the problem is following the load shedding in order to achieve stability in the system, you're running into a fundamental problem, now you have to restore the system. Now you're running into an area called cold load pickup and you don't have the support for the pickup, particularly in industrial plants, because that is fairly dynamic. I just want to know how would you handle that, the cold load pickup which you don't have SCADA to help you on that issue. So that was the question. Because a lot of time what we find from operators is that you shed the load in order to achieve the stability, then when you restore the load you cause more instability, and your systems go down. We've seen that many times, particularly when there is no margin in the system. So just want to know how you handle that.

**C. Rehtanz:** The utility expects that from the wide area system you use, load shedding will be fewer and that we

have to shed less load. This also decreases the problem of switching the loads again. But for such a system we use for restoration we use all the same procedure as before, and so far I have no new suggestion on how to use such a system for load restoration again. So we use everything that is already available for restoration. But if the restoration fails, then probably the wide area protection operates again and tries to stabilize the system.

**D. Koval:** After you shed load, the load is significantly different. You can not assume it is the same. It is a different pattern and magnitude. It is cold load but you have no SCADA to predict that.

**C. Rehtanz:** The system model receives the snapshot of the load the moment we shed the load. Therefore, we can determine the actual load we want to switch off.

**D. Koval:** But you can't tell what you pick up.

**C. Rehtanz:** Yes. That's clear. You're right.

**D. Koval:** There is no way.

**Chairman** (H. Sasaki): As far as I understand, Arum said that, as a measure to avoid the hidden failures, on line setting of relays is one alternative. I would like to ask ABB persons that in wide-area protection, they want to integrate on line setting.

**A. Phadke:** In my discussion, I didn't promote on line setting. The issue was that, at least in my presentation here, there are some unpredictable hidden defects in the relay, which you have to accept. Therefore, the kind of things you do, if that particular protection system happens to be critical from the system point of view, you would put either additional equipment in the substation to make sure the decision is correct, or in that location switch from an OR condition of several protection units to a voting system. So there is no talk of changing anything on-line as far as setting, that concerned more or less a supervision of an existing setting. On the other hand, the principle of adapted relaying, which we didn't discuss here, does allow some changes in protection. You wouldn't try to change settings while a fault is in progress, you would do it earlier depending on system conditions.

**D. Karlsson:** All relay manufacturers today give you an opportunity to have different setting groups. Most companies for different setting groups, and you have one setting group for different kinds of operating conditions, and that can be changed on-line but before the fault. So depending on your system operating condition, if you have islanded operation, or if you have high load, low load, or whatever, you may set the settings in group, where you can change the settings. This can be used also for adaptive relaying.

**Chairman** (H. Sasaki): Thank you. I would like to close the first half of Session two.

## New Principles for System Protection Schemes in Electric Power Networks

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**Abstract** - This paper describes basic principles and philosophy for System Protection Schemes (SPS) or Remedial Action Schemes (RAS) against large power system disturbances, as well as examples on how it can be designed and implemented. The protection scheme can be used to mitigate voltage collapse, loss of synchronism, power oscillations, etc. The proposed system protection scheme is based on a number of system protection terminals, which are connected via a system wide data communication network and synchronised by GPS technology. The proposed system is very flexible and comprises a large number of optional protection functions of various complexity and capability.

**Key Words:** Wide Area Protection, System Protection Schemes, Voltage Stability, Angular Stability, Electric Power Systems

### Introduction

A continued load growth without a corresponding increase in transmission capacity has reduced operational margins in many power systems, and led to operation of power systems closer to their stability boundaries. Operation of power systems closer to their stability limits together with the on-going world wide trend of re-regulation of power systems as well as increased need for more accurate and better monitoring of power networks is likely to increase power utilities interest in system protection schemes.

So far traditional relay manufacturers have been focused on equipment protection, such as line protection, transformer protection, etc. Equipment protection is designed to isolate the faulted or overloaded equipment and to maintain the power supply to the healthy part of the system. System protection schemes, on the other hand, address situations where no particular equipment is faulted or overloaded, but the power system is severely stressed and in transition towards instability, resulting in a wide-spread blackout, if no remedial actions are taken.

Due to the ever-increasing dependency of modern society of reliable power supply and difficulties in obtaining new right-of-ways, system protection schemes can play a very important role for increasing reliability of power systems in the future. System protection schemes are dealing with incidents with a relatively low probability but at the same time enormous consequences. The risk, defined as the product of probability and consequence, for such events is therefore hard to derive. Strategies for reducing the risk

and effects of major disturbances in the power system are a major concern for power utilities – both regarding planning and operational aspects.

All protection systems have to meet high requirements on reliability, which further can be divided into high dependability and high security. High dependability is concerned with a low probability of not having a failure to operate and high security is concerned with a low probability of an unwanted operation. A system protection scheme should, naturally, have high reliability and in particular if a failure to operate or an unwanted operation might make the situation worse or if it includes (non-discriminative) load shedding.

During the last ten years a lot of efforts have been put into discussions, research, and theoretical work in the area of system protection schemes, sometimes called wide area protection. Prototype testing of transducers and algorithms, especially developed for mitigation of system wide disturbances, has also been performed during the last years. It now seems reasonable to believe that time has come to merge the accumulated knowledge concerning power system behaviour during extreme contingencies, available actions for power system instability mitigation, and the presently available measurement and communication technology into commercially available products.

### States of Operation

The aim of system protection schemes is to protect the integrity of the overall power network, which corresponds to an operational state of the power system being either normal or alert. This state of operation is characterised by fulfilled power flow (algebraic) equations, i.e. existence of a power flow solution, and no immediate risk of loss of synchronism in the electric power system.

The concept of states (or modes) of operation was introduced already in 1967 in a paper by Dy Liacco [1]. Three states of operation were introduced: preventive, emergency and restorative, where the preventive state also was referred to as the normal state of operation. The terminology preventive was used to emphasise that actions taken in this state were aimed at preserving, and if possible improving, system security during otherwise normal operating conditions. Use of the term preventive instead of normal was introduced to stress the importance of system security aspects and indicates that the control objective in this state of operation is to “continue indefinitely the satisfaction of customer demand without interruption and at minimum cost” [1].

The three states earlier introduced by Dy Liacco were in a now 'classical' paper by Fink and Carlsen [2] augmented with two additional states. The thereby obtained five states of operation were named: normal, alert, emergency, in extremis and restorative. It is these five states and the corresponding transition chart provided in [2] that forms the basis for Fig. 1 as well as the continued discussions about states of operation in this paper.

The term protecting the integrity of the power system can be related to securing the operation of the power system in the normal and, for shorter terms also, in the alert states of operation. The aim of the SPS is to sense and identify situations, which normally lead to the "in extremis" state, take actions and bring the system back to (at least) the alert state. The curved arrow in Fig. 1, which as described above is based on [2], indicates this transition between states of operation in a power system. Introduction of system protection schemes can by providing suitable countermeasures help avoiding (serious) network disturbances, by stopping or limiting the breakdown of the system, i.e. the transition into the "in extremis" state by use of so called "emergency control actions".

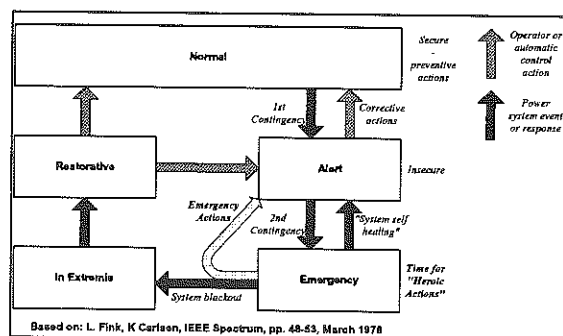


Figure 1. Power system operating states, based on [2].

The curved arrow in Fig. 1 illustrates the action of SPS. If the encountered disturbance is very severe, the transition between the different states of operation may in some cases take place without passing through the 'intermediate' stages. Examples are transition directly from the normal state to the emergency state if the encountered disturbance is more severe than the faults described in the design criteria for the power system, and also transition directly from the alert state to the "in extremis" state in case of a very severe disturbance. Irrespective of the precise path taken during the transition between states of operation, the general aim and purpose of an SPS is the same.

The states of operation are discussed in connection with Fig. 1, where five states of operation are illustrated. See Appendix for a more mathematical 'definition' for the above states of operation, while the below descriptions of these states in words is based on [2]. In a normal operating state, the power generation is adequate to supply the existing load demand. No equipment is presently overloaded. All constraints on the power system are satisfied. In this normal operating state, normal reserve margins are present, which margins are sufficient to provide a certain level of security. These margins are

normally designed with respect to the stresses to which the system may be subjected, both regarding generation and transmission. A power system is in the normal operating state during the vast majority of the time. Any deviation from this state is an exception, however, a serious one. *Preventive* actions are taken by the system operator, AGC, AVR, tap-changer controllers, etc. to meet changes in the operational conditions due to normal load variations, within the normal state of operation, according to Fig. 1.

If conditions nevertheless are changed in such a manner that the provided security level may become too small, or the probability of disturbances may have increased, the system enters the alert state. In this alert state, all constraints of the system would still be satisfied in an isolated view, i.e. no objects are operated outside their boundaries (limits). However, the whole system is less secure than in the normal operating state. The available margins to cope with disturbances may easily be exceeded even by rather simple and common faults, which then could result in violation of some system constraints. Equipment would be more or less severely overloaded, compared with its rated capabilities. In the alert state, *corrective* actions can be taken to restore the system back into the normal operating state. The term protecting the integrity of an overall power system can as discussed earlier in this context be related to securing the operation of the power system in the normal and, for shorter terms also, in the alert states of operation.

If such corrective actions do not take place before another sufficiently severe disturbance, the system is transferred into the emergency state. Here, system constraints are violated and the security of the system is breached since there does not exist any security level. The system is however still intact during this emergency state and emergency control actions or "heroic measures" could be initiated in order to restore the system to at least the alert state. Emergency control action should be directed towards sparing as many pieces of the system as possible and avoid a total collapse of the network. Once a system has entered the emergency state, the deliberate control decisions and actions that are appropriate to the normal and even the alert state are no longer adequate. More immediate action is called for.

If the emergency control actions are too slow or inefficient, the disturbance over stresses the system. The system starts to disintegrate into the "in extremis" state. In this state system constraints are no longer valid and major portions of the system would not be intact any more and a significant part of the system load would be lost. If the collapse is halted before all parts of the system are lost, some remaining equipment will operate within rated capability and the system will enter into a restorative state. Here, control actions are taken to pick up lost load and reconnect the system, even if the entire system may not be restored immediately. From this state, the system could transit to the alert state or go back the entire way to the normal operating state. The actual path depends on the circumstances of the emergency situation, and the restoration process.

### Power System Phenomena

There are only a limited number of fundamental conceptual power system phenomena involved in wide area disturbances, and wide area protection systems have to be designed to recognize these phenomena:

- o Transient angle instability, i.e. first swing angle instability, the time available for remedial actions is in the order of fractions of a second.
- o Small signal angle instability, i.e. power oscillations, the time available for remedial actions is in the order of seconds up to minutes.
- o Frequency instability, i.e. imbalance between generation and load, the time available for remedial actions is in the order of a few seconds.
- o Short-term voltage instability, i.e. there is no load flow equilibrium point available immediately after the clearance of the initial disturbance, remedial actions are required between fractions of a second and up to a few seconds. Short-term voltage instability is rather uncommon. The typical example is bush fires across a number of parallel transmission lines. Example: South Florida, May 1985 [3].
- o Long-term voltage instability, i.e. an equilibrium point is reached immediately after the clearance of the initial disturbance, but due to power system slow dynamics, the system is in transition towards an instability, the time scale for remedial actions is in the order of tens of seconds. The system survives the initial disturbance, i.e. an equilibrium point is reached immediately after the disturbance, but due to load recovery and control system actions (such as on-load tap-changer operation) the power demand is increased and the weak system will finally collapse. Examples: Sweden, December 1983 [4],[5] and France, January 1987 [6]. For long-term voltage instability due to load growth the time scale is tens of minutes. Without any initial disturbance a rapid load growth can slowly bring the system to a collapse. Example: Tokyo, July 1987 [7].
- o Cascaded line or generation tripping. Certain disturbances may result in cascaded line or generation tripping, due to overload (or conflict with distance protection settings), the available time for remedial actions is usually in the order of a second and longer.

Based on these phenomena, protection functions can be designed, using simple logic and arithmetic functions, or complex artificial intelligence. The outputs from these protection functions should thus result in remedial actions, such as load or generator shedding, call for reactive power or real power support, tap-changer blocking, etc.

### SPS Design and Operation Principles

The general structure of an SPS is shown in Fig. 2. The

system protection scheme comprises an input interface towards the power system process, some sort of decision making process or logic solver, and finally, an output interface where the actions to save the power system are ordered. The input interface comprises analogue inputs, such as voltages and currents, as well as binary signals, such as circuit breaker status. Both electric variables and direct detection of events can be used as inputs. Actions are usually trip or control signals.

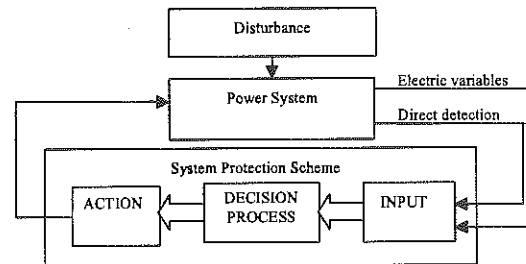


Figure 2. General structure of a system protection scheme.

This section is a brief summary of the basic principles of SPS design and its operation procedure. We start with the system initial conditions (to the upper left in Fig. 3); these are known and can be planned for in a short time scale. The actual system condition can be used as inputs to the SPS system (the arrow to the right in Fig. 3).

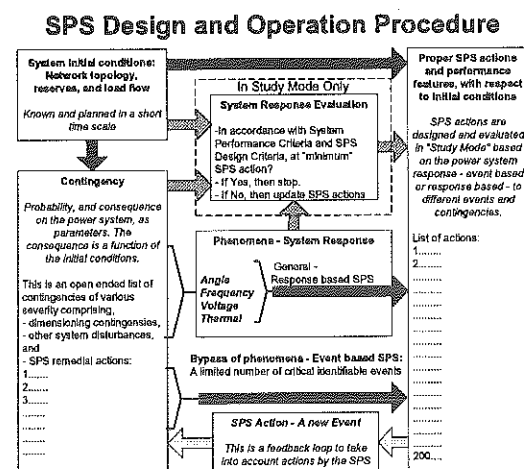


Figure 3. Block diagram showing the SPS design and operation procedure [8].

Based on certain system conditions, an infinite number of events or contingencies can occur. Each event affects the power system and an SPS can be based either on the event itself - *event based* - or on the power system response to the event - *response based*. An event based SPS can be used for a limited number of very critical events, e.g. loss of a critical line or generator.

Event based SPS are used when the critical event is easy to identify, the consequences of the event are critical for the system stability and remedial actions are to be taken very quickly. Response based SPS are slower than event based, because they have to wait for the system response, e.g. the frequency or the voltage to drop below a certain setting. On

the other hand response based SPS are more general; no matter what the origin of the disturbance was, it reacts on critical power system quantities, such as voltage, frequency, power, etc. The response based SPS is also efficient for events that are not explicitly identified. Actions based on the time derivative of system quantities, such as voltage and frequency, may trigger immediately after a contingency, but are still universal, without a strong connection to a particular disturbance scenario.

SPS design can be derived from off-line studies based on the performance criteria for the power system and system response to events and contingencies. The requirements on the SPS can then be identified as the necessary actions to fulfil the system performance criteria, with respect to the applied contingencies and/or disturbances. When the requirements on the SPS are identified, the SPS design, to fulfil these requirements, can be done. The SPS action is then interpreted as a new event, in a feedback loop into the power system. The system response is studied and it has to be checked that the system performance criteria are fulfilled. Of course, an SPS or defence plan can comprise a large number of coordinated actions, which very often act in a cascaded manner, e.g. under-frequency controlled load shedding occurs in a number of steps at different frequency levels and/or with different time delays.

The SPS operation is very similar to the design, except for the off-line studies, where the SPS design is made based on credible contingencies, power system response and system performance requirements. Based on either events or system response the SPS take some actions, which are regarded as new “remedial events”. Depending on the system response, we either return to an acceptable state of operation or further SPS actions have to be taken.

### SPS Realization Structure

Based on the above presentation of states of operation, it follows that the intentional automatic control action that can be taken to save the power system or restore sufficient reserve margins, can be divided into preventive and corrective actions. During normal operation, the focus is on economic aspects of power system operation, and economic operation is hence playing the more important role. While during more stressed network operational conditions, such as in an alert state, and in particular during emergency situations, the focus for control objectives shifts towards stability considerations.

The ultimate objective here is keeping as much as possible of the network intact and generators connected to the grid. The breakdown normally results in one or more severe problems in the power system. The main concern in the emergency state is of course system security. System protection schemes form in this respect a last line of defence in case of severe disturbances. The aim of actions taken by SPS is to provide uninterrupted power supply by use of sometimes rather ruthless methods, i.e. by taking actions that could be referred to as measures of last resort (and which would not be used during normal operational conditions). The objective of the system

protective scheme is hence to retain power system operational security.

Tailor-made wide area protection systems against large disturbances, designed to improve power system reliability and/or to increase the transmission capacity, will therefore most likely be common in the future. These systems will be based on reliable high-speed communication and extremely flexible protection devices, where power system engineering will become an integrated part of the final solution. This type of high performance protection schemes will also be able to communicate with traditional SCADA systems to improve functions like DSM, DA, EMS and state estimation.

Based on time synchronised measurements of voltage and current by Phasor Measuring Units (PMUs) at different locations in the network, real-time values of angle differences in the system can be derived with a high accuracy and a high sample rate, e.g. half the system frequency (25/30 Hz), see Fig. 4. With this new type of real-time measurements, efficient emergency actions, such as PSS control, based on system wide data, load shedding, etc., can be taken to save the system stability in case of evolving power oscillations.

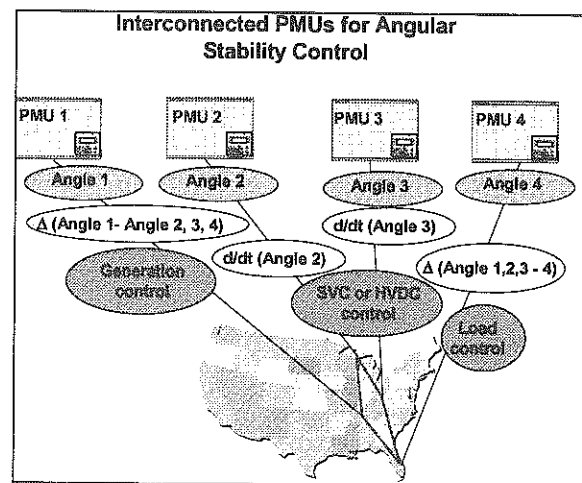


Figure 4. Wide area angular stability control.

Based on different criteria and algorithms, voltage stability indicators can be derived. These indicators can be used for pure information to the system operator, decision support to the operator or automatic actions to counteract a pending voltage instability. The criteria could be simple undervoltage detection or high reactive power flow in combinations, or more advanced local criteria, such as the VIP (Voltage Instability Predictor) [9], or system wide criteria, such as indices based on the minimum singular value of the power flow Jacobian matrix or related submatrices [10]. The sensors have to be placed at different critical locations all over the power system, see Fig. 5. In this way an overview of the overall system condition can be achieved and appropriate actions to mitigate a voltage collapse can be taken. Both protective actions, such as shunt capacitor switching or load shedding, and emergency control, such as different request for HVDC emergency active power support or SVC reactive power support, can

be implemented.

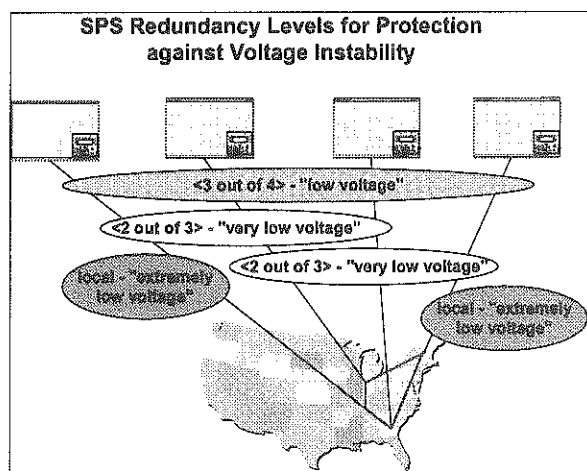


Figure 5. Wide area voltage stability control.

A very flexible and powerful wide area protection system can be designed based on de-centralised System Protection Terminals (SPTs). The system protection terminals are installed in power system substations, where measurements are to be taken or actions are to be performed and tied together with a high capacity communication system, see Fig. 6, where the system protection scheme implementation and interfaces are shown.

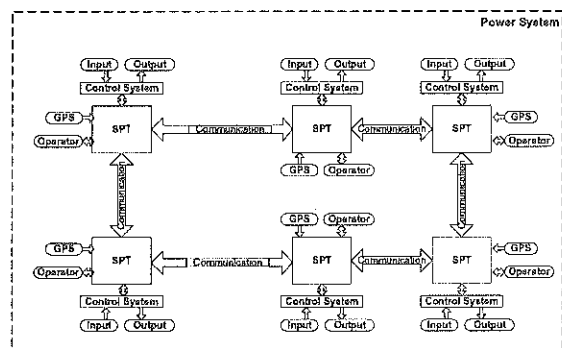


Figure 6. Box-to-box based wide area protection system, design and interfaces.

### System Protection Terminal

The system protection terminal is designed from a protection terminal and fulfils all requirements concerning mechanical, thermal, EMC, and other environmental requirements for protection terminals. Design and interfaces of a system protection terminal is shown in some more detail in Fig. 7.

The terminal is connected to the substation control system, CTs and VTs as any other protection terminal. For applications that include phasors, i.e. phase angles for voltages or currents, a GPS antenna and synchronization functions are also required.

The system protection terminal comprises a high-speed communication interface to communicate power system data between the terminal databases. In the data base all

measurements and binary signals recorded in that specific substation are stored, and updated, together with data from the other terminals, used for actions in the present terminal. The ordinary substation control system is used for the input and output interfaces towards the power system process. The decision making logic contains all the algorithms and configured logic necessary to derive appropriate output control signals, such as circuit-breaker trip, AVR-boosting, and tap-changer action, to be performed in that substation. The input data to the decision making logic is taken from the database, and reflects the overall power system conditions.

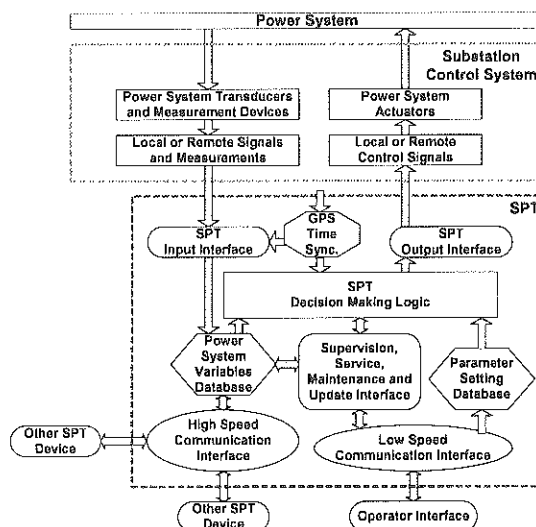


Figure 7. System protection terminal, design and interfaces.

A low speed communication interface for SCADA communication and operator interface should also be available. Via this interface phasors can be sent to the SCADA state estimator for improved state estimation. Any other value or status indicator from the database could also be sent to the SCADA system. Actions ordered from SCADA/EMS functions, such as optimal power flow, emergency load control, etc., could be activated via the system protection terminal. The power system operator should also have access to the terminal, for supervision, maintenance, update, parameter setting, change of setting groups, disturbance recorder data collection, etc.

Fig. 8 shows examples of terminal interfaces and outputs for system protection terminals aimed for phasor measurements (PMU) and voltage stability applications (VIP). The proposed system protection terminal is based on a regular modern protection terminal, with great flexibility and good user experience. By using a well established and accepted protection terminal as the base for a system protection scheme, all requirements concerning CT-/VT-connections, binary inputs and outputs, etc., are immediately fulfilled. The development cost will also be quite moderate, and time to market for a full system will be rather short.

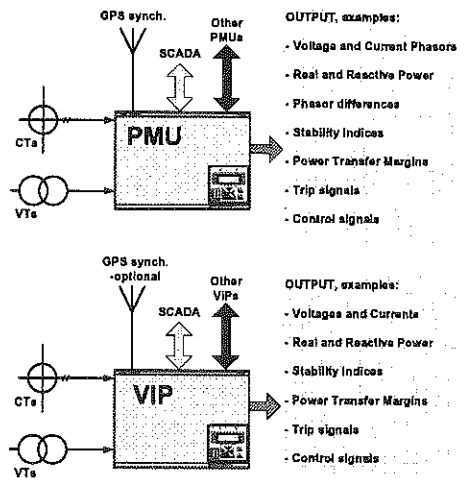


Figure 8. PMU and VIP terminal interfaces and outputs.

### Pilot Installations

**Norwegian – Swedish Inter-tie at Hasle.** The project is a cooperation between Statnett and ABB, where the VIP-algorithm [9] has been implemented in a system protection terminal prototype. The terminal is in operation, on a recording base, since late 2000. It is located close to the border of Sweden, see Fig. 9, and measures the bus voltage and the sum of the currents coming from Norway as well as the sum of the currents going to Sweden. The load impedance, calculated as the bus voltage divided by the total load current, is then derived. The source impedance is calculated from the change in bus voltage and the change in load current caused by a load change.

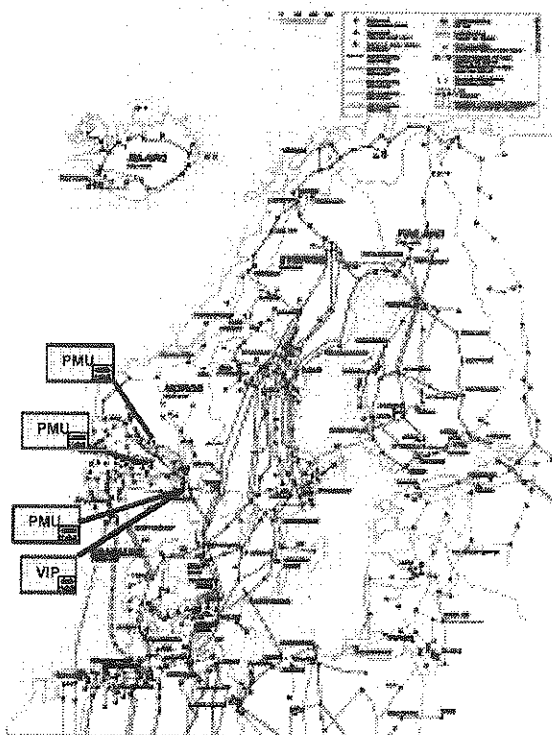


Figure 9. PMU and VIP prototype installations in Norway.

The results are the tracked load and source impedances as functions of time, an example is shown in Fig. 10.

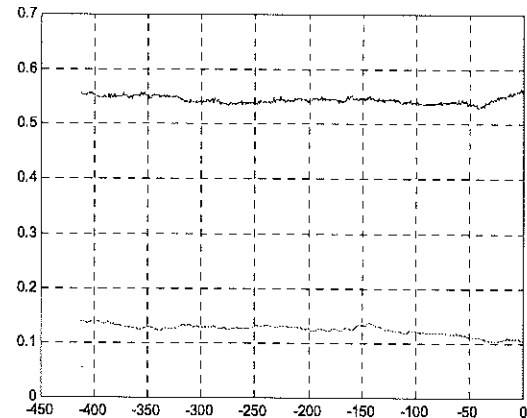


Figure 10. Load and source impedance [pu] as recorded in Hasle, as functions of time [s].

Three PMU-boxes are also being installed in the Southern Norway Statnett system. The main purpose of the installation of these PMUs, besides testing the new technology, is to evaluate potential for improvements in the state estimation process if key buses are equipped with phasor measurement units.

**Damping Improvement project in Iceland.** The Icelandic transmission system is based on a 130 kV ring around the island, see Fig. 11. The load centre is located in the southwest, around Reykjavik, and the main generation area is in the mid-south around Sigalda. However, two major plants are located in north part; Blanda (150 MW) and Krafla (60 MW). During high load conditions the power flow in the ring is from the north to the south. If a fault occurs (most frequently on the west side) the ring is split and all the power has to go through the eastern part. Rather heavy, poorly damped oscillations, might occur.

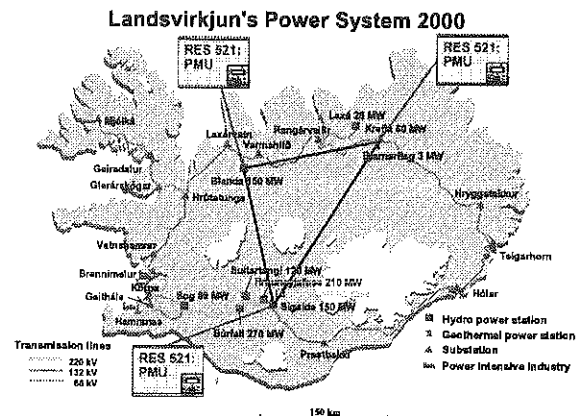


Figure 11. The Island power system, equipped with PMUs.

The idea with this pilot project is to install PMUs in three critical nodes and use the system angles as inputs to the power system stabilizers on the generators in the north. As a result it will be demonstrated if a more efficient damping algorithm can be derived based on voltage angles from



different parts of the system compared to traditional PSS, based on a local active power criterion. So far two of the PMU units have been installed. The communication between these units is working properly, but there are yet no results available concerning damping improvement.

### Discussion

Traditionally, remedial action schemes have been hub based, i.e. all measurements and indicators are sent to a central position, e.g. a control centre, for evaluation and decision. From this central position, action orders are then sent to different parts of the power system. Such a centralised system is very sensitive to disturbances in the central part. With the ring based (or WAN) communication system, proposed in this paper, a much more robust system can be achieved. One communication channel can for example be lost without any loss of functionality. If one system protection terminal fails in a flat de-centralised solution, a sufficient level of redundancy can be implemented in the neighbouring terminals. In other technological areas the decision power is moving closer to the process, with increasingly more powerful sensors and actuators, for decisions based on rather simple criteria. Such an independent system protection scheme, based on powerful terminals, can also serve as a backup supervision system that supplies the operator with the most critical power system data, in case of a SCADA system failure.

The proposed system protection scheme based on system protection terminals can provide a wide range of control and protective actions, from quite simple protective functions to more advanced emergency control schemes, based on the same platform. It is believed advantageous for emergency control devices, such as system protection terminals, to have this flexibility concerning functionality and applications as well as to be designed as (independent) building blocks suitable for introduction into advanced system protection concepts. The proposed system protection terminals can constitute important building block in a future integrated control concept for improving reliability and security of large interconnected electric power networks.

The proposed de-centralised concept with 'intelligence' and 'decision power' in the local system protection terminals hence provides a great potential for building robust system protection schemes. The proposed de-centralised approach provides locally based decision tools, which do not rely on communication links and central computing facilities to perform emergency control actions, when needed. System protection schemes based on intelligent terminals are more autonomous than centralised schemes, but still provide global information, at least as long as the communication system is functional. In a recent paper on reliability and vulnerability of infrastructure systems it was even stated that "centralized control is likely to suffer from the very problem it is supposed to fix" [11].

### Conclusions

This paper indicates the great potential for wide area protection and control systems, based on powerful, flexible and reliable system protection terminals, high speed, communication, and GPS synchronization in conjunction with careful and skilled engineering by power system analysts and protection engineers in co-operation. Relation between SPS action and states of operation as well as differences between event based and response based system protection schemes are discussed. A concept for wide area protection and emergency control, based on protection terminals and a communication network, is presented.

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## Biography

**Per-Anders Löf** received his Ph.D. degree in Electrical Engineering from Royal Institute of Technology, Stockholm, Sweden in 1995. His research was in the area of static analysis of long-term voltage stability. He has been employed at ABB Corporate Research in the department of High Voltage Electromagnetic Systems in Västerås, Sweden, since 1995. During 1996-1997 he was on leave from ABB, working at the Office of Science & Technology at the Embassy of Sweden in Washington, DC, USA. Dr. Löf is a member of IEEE.

## APPENDIX

### Grouping into States of Operation

The following text is an attempt to define the states of operation based on the concepts presented in [2], in both mathematical and verbal terms.<sup>1</sup>

A conventional model for a mathematical description of power systems is based on one set of differential and one set of algebraic equations, i.e. a differential-algebraic system of equations or a DAE model. A general form for a DAE model can be written as:

$$\dot{\underline{x}} = F(\underline{x}, \underline{y}, \underline{p})$$

$$\underline{0} = G(\underline{x}, \underline{y}, \underline{p})$$

with a known set of initial conditions. In the above formulation,  $\underline{x}$  is a vector of dynamic system states, sometimes called state variables,  $\underline{y}$  is a vector of algebraic, power flow, states (i.e. system variables associated with the non-linear algebraic constraints) and  $\underline{p}$  is a vector of parameter values.

Another set of equations representing inequality constraints can be added to the above system of differential-algebraic equations. The inequality constraints can for example represent system variables, such as currents and voltages, which must not exceed maximum levels representing the limitations of physical equipment.

$$\dot{\underline{x}} = F(\underline{x}, \underline{y}, \underline{p})$$

$$\underline{0} = G(\underline{x}, \underline{y}, \underline{p})$$

$$\underline{0} > H(\underline{x}, \underline{y}, \underline{p})$$

where the last set of equations, the inequality constraints, if necessary could be split into one set of strict inequalities and one set of inequalities greater or equal than zero; i.e.  $\underline{0} > H1(\underline{x}, \underline{y}, \underline{p})$  and  $\underline{0} \geq H2(\underline{x}, \underline{y}, \underline{p})$ . In most instances, it is possible to re-write all types of inequality constraints into strict inequalities.

<sup>1</sup> Note: Underlined symbols ( $\underline{x}$ ,  $\underline{y}$ ,  $\underline{z}$ ,  $\underline{p}$ ) and numbers (zero) denote vectors, while the capital letters F, G and H are used to denote state equations, equality and inequality constraints, respectively. Derivatives of the state variables with respect to time are written as 'x-dot'.

The states of operation can be based on the above basic DAE model augmented with a security margin giving the distance to defined insecure state.

During normal operations reserve margins for transmission as well as for generation must be sufficient to provide an adequate level of security with respect to the stresses to which the system may be subjected. If a disturbance according to the design criteria applicable to the studied power system would result in a violation of some inequality (or even worse equality) constraints, the margin for this case would be considered insufficient; in the following discussion set to a negative value. The equipment would e.g. be overloaded more or less severely above its rated capabilities

The dynamic states describe the transition, i.e. trajectory for the set of state variables, between equilibrium points, where  $dx/dt=0$ . The states of operation to be defined are mainly aimed at power system operation, e.g. in control centres, where the main parts of studies, today, are performed in a static or at least a quasi-static environment. In general, power system dynamics can be divided into electromagnetic, electromechanical and longer-term phenomena. This division is based on the time-scale in which different phenomena exert their main influence.

All electromagnetic and electromechanical dynamics of generators as well as all dynamics of network and loads are in the following discussion considered to be at steady-state, i.e. the corresponding state variables are at equilibrium values. This seems a reasonable assumption for the division into states of operation for power system operational considerations, while transients of course must be taken into consideration for both operational and protection consideration. Note that the above condition does not state whether a found equilibrium point is stable or not, if such a point at all exists.

An equilibrium point is asymptotically stable if all nearby solutions not only stay nearby, but also tend to this equilibrium point as time goes to infinity. For normal operation it is assumed that the operating point of the studied system of state variables will after the last switching operation, i.e. for the post-fault condition, lie in the region of attraction of the post-fault equilibrium point which is an asymptotically stable equilibrium point, if such a point exists. If this assumption is severely violated, it will also manifest itself in the equality and inequality constraints.

Three sets of generic equations, one differential and two algebraic thus govern the power system operation. According to the above description, the differential set describes the physical laws governing the dynamic behaviour of the system's components. The two algebraic sets comprise "equality constraints" and "inequality constraints". The equality constraints refer to the system's total load and total generation. The inequality constraints state that some system variables, such as currents and voltages, must not exceed maximum levels or fall below minimum levels. Maximum levels can e.g. represent limitations due to thermal stress of physical equipment.

Based on the above discussion, it seems that the systems of

equations for equality and inequality constraints together with a measurement of the stability margin are sufficient for obtaining a set of equations, which uniquely can define the five states of operation. This mathematical formulation can later be used for security assessment, transmission and production planning as well as operational purposes.

The following mathematical formulation could hence form a basis for the division into states of operation. The basis includes the equality and inequality constraints, i.e.

$$\underline{0} = G(\underline{x}, \underline{y}, \underline{p})$$

$$\underline{0} > H(\underline{x}, \underline{y}, \underline{p})$$

together with a "measurement" of the security margin, lets call it  $M$ . If  $M$  is positive,  $M > 0$ , then the security margin is sufficient with respect to design criteria for the power system, i.e. dimensioning rules. The equality and inequality constraints are either considered "ok" if they are fulfilled or "violated" if at least one of them is not fulfilled, while the margin is considered "ok" if it is positive and "violated" if it is negative.

The states of operation defined by Fink and Carlsen, could in the above presented mathematical formulation be classified according to the below listing:

|              |              |                                                                            |
|--------------|--------------|----------------------------------------------------------------------------|
| Normal:      | $G$ ok       | i.e. $G(\underline{x}, \underline{y}, \underline{p}) = \underline{0}$      |
|              | $H$ ok       | i.e. $H(\underline{x}, \underline{y}, \underline{p}) < \underline{0}$      |
|              | $M$ ok       | i.e. $M > 0$                                                               |
| Alert:       | $G$ ok       | i.e. $G(\underline{x}, \underline{y}, \underline{p}) = \underline{0}$      |
|              | $H$ ok       | i.e. $H(\underline{x}, \underline{y}, \underline{p}) < \underline{0}$      |
|              | $M$ violated | i.e. $M < 0$                                                               |
| Emergency:   | $G$ ok       | i.e. $G(\underline{x}, \underline{y}, \underline{p}) = \underline{0}$      |
|              | $H$ violated | i.e. some $H(\underline{x}, \underline{y}, \underline{p}) > \underline{0}$ |
|              | $M$ violated | i.e. $M < 0$                                                               |
| In extremis: | $G$ violated | i.e. $G(\underline{x}, \underline{y}, \underline{p}) \neq \underline{0}$   |
|              | $H$ violated | i.e. some $H(\underline{x}, \underline{y}, \underline{p}) > \underline{0}$ |
|              | $M$ violated | i.e. $M < 0$                                                               |

As shown, the above four states of operation can be defined by use of these three mathematical relations.

During *normal* operation, both sets of algebraic equations are fulfilled and the security margin is sufficient with respect to applicable design criteria. The transition to the *alert* state occurs when the security margin no longer is adequate, i.e.  $M < 0$  in the above mathematical formulation. If the situation continues to grow worse and (at least some) inequality constraints no longer are satisfied, the state of operation changes over into the *emergency* state. If the operational situation further

deteriorates and also equality constraints are violated, the state of operation crosses over into the "*in extremis*" state, which corresponds to a partial or complete blackout of the electric power network.

## New technology for safe critical applications in real time

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### Summary

Several techniques are available for constraint satisfaction problems. Most of them lack real time capability and distributed computational properties. Configuration of complex systems has today become a competitive edge, e.g. within e-business. The other side of the same coin can be used for diagnosis and simulation of safe critical applications. This paper gives a scientific background and comparison of methods for constraint satisfaction problems implemented in real time environment. Especially, the technique and its features of the array-based logic will be illustrated by three examples.

The examples are:

1. Modeling and simulation of system wide protection applications of power systems
2. Modeling, simulation and implementation of safe critical switching in power systems
3. Modeling, simulation and implementation of safe critical systems of automatic train control

Array-based logic is a novel technology, which is founded on a geometrical representation of logic in terms of nested data arrays. In this representation, logical inferences are executed on finite domain systems by a few standardized array operations. In computational practice, array-based logic makes it possible to solve large-scale constraint problems with  $M^N$  combinations very efficiently. The major advantages of the technology are completeness, compactness, and speed of simulation (real-time capability), all of which derive from intrinsic properties of the underlying geometrical model. A system in array-based logic is considered analogously to electrical networks and is thus described by the constraints of the isolated elements as well as the constraints of the interconnected elements (the system topology). All system constraints are eliminated in accordance with the methods known from electrical network theory and other engineering disciplines rooted in classical physics. The configuration space is represented explicitly in terms of nested data arrays and the system can therefore be simulated in real-time by co-ordinate indexing on these arrays. This data driven approach makes it suitable for parallel processing, which is an important quality for distributed systems.

### Keywords

Array-based logic, constraint elimination, configuration space, consistency verification, system environment interaction, safe critical switching, real-time processing.

### Introduction

In recent years, there has been an increasing interest in, what has variously been known as "constraint logic programming", "constraint satisfaction", or "constraint solving". This is due to the commercial interest in software tools for solving industrial problems characterized by a complex multitude of constraints or bindings, often related to some mix of purely technological considerations with those of competitiveness and efficiency. Typical in this respect is the configuration of complex products with a host of combinations, such as cars or computers. But constraint satisfaction problems also arise in many other areas as for instance production planning or job scheduling. In the computer industry, software tools for solving problems of this nature have been developed currently since mid 1980s. Originally, these applications of constraint satisfaction were based on programming languages such as Prolog, that were developed in the field of AI (Artificial Intelligence) to cope with complex problems of a logical nature. Gradually, however, heuristic methods were introduced to solve such problems more efficiently. Today, as a result of this development, there are several commercial tools available on the market.

However, none of the commercial tools are suitable for real-time handling of large-scale systems with a multitude of constraints like, say, railway interlocking systems or other systems to be discussed later. During 1993 to 1997 the two companies, Sydkraft AB and Bang & Olufsen Technology A/S, developed the new technological platform for solving complex constraint problems on finite domains. The work has been carried out in a joint EUREKA project (EU 1007 'EMCON') in co-operation with the Electric Power Engineering Department at the Technical University of Denmark, which has contributed with the scientific foundation of array-based logic. The basic idea of array-based logic is to explore the consequences of considering truth-values as physical measurements [1] and to adopt the constraint solving methods known from classical physics. Since 1997 the technology has further been developed and used in solving complex constraint problems. See the links: [www.arraytechnology.com](http://www.arraytechnology.com) and [www.cybrant.com](http://www.cybrant.com).

### The Scientific Background

Although often presented as a new idea over the past decade, constraint satisfaction as a basic scientific concept dates back at least to the publication of Lagrange's *Analytical Mechanics* in 1788. In his famous work, Lagrange introduced the organized handling of the constraints or bindings of discrete mechanical systems in terms of abstract geometrical models, which since

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then has contributed the scientific foundation for dealing with discrete systems in physics and engineering. Thus, of pertinent interest later on in this paper, Lagrange showed that if the constraints could be eliminated, all possible states of the system could be described in terms of a set of independent parameters, the "degrees-of-freedom" of the system. Thus the equilibrium states could be determined by variational methods as a so-called "free variational problem". On the other hand, if the constraints could not be eliminated, he introduced the method of unknown multipliers to deal with them in non-eliminated form. In the ensuing development over the following century or so, some of the most famous names in the history of physics introduced various classifications of constraints and devised methods for the organized handling of constraints falling into these classifications. For example, as early as 1798 Fourier introduced inequality constraints in addition to those in terms of equalities, while in 1847 Kirchhoff introduced graph theory (in connection with his famous two laws) to deal with topological constraints in a systematic manner. Since the theoretical concepts and methods for constraint satisfaction thus developed in classical physics have stood the test of time for more than two centuries, it is puzzling to observe the complete lack of influence it has had upon the above mentioned development over the past decade in AI. In 1971, Cook showed that satisfiability, a special case of constraint satisfaction, belongs to the class of NP (non-polynomial)-complete problems. The year after Karp exhibited the intractability of NP-complete problems and proved seven more problems to lie in this class. These were applications from logic, scheduling, graph theory and set theory, in particular the well known travelling salesman problem. In the geometrical approach to logic introduced by Frankzen [2], truth-values are considered as measurements with associated scale-forms in the sense of physics rather than something intrinsic to language. The advantage of this view is that it now becomes possible to treat logical arguments as systems in terms of geometrical models, completely by analogy to physical systems. The crucial point is that all possible solutions are considered simultaneously without performing any assertion in order that elimination of the constraints can be performed *prior* to the act of assertion, which is then considered as an impressed force in mechanics. The set of all possible solutions may be formulated in terms of orthogonal arrangements of data, whence we talk about *array-based logic*. In a very abstract way we may consider these orthogonal arrangements as geometrical models spanned by a reference system of axes. This admits that these models may be associated with the notion of invariance under transformations of reference frame. In other words, as Frankzen pointed out in 1978 [2], the laws of propositional logic (as well as extensions to multi-valued logic) may be considered by analogy to the laws of physics as those properties that remain invariant from under a mathematical group of transformations. The importance of this view on logic ought not to not be underestimated, because it is now possible to show that predicate calculus and relational algebra are but isomorphic representations of the same abstract group as that characterizing propositional logic. From a technological point of view, this is a tremendous simplification, since it means that reasoning can now

be carried out in terms of only three, purely geometrical operations. Briefly described these operations are:

1. An outer product in the Cartesian sense to establish arrays of all possible solutions;
2. The operation of taking out planes or hyper planes by equating two or more axes;
3. A reduction by logical addition or multiplication, which generalizes the elimination process of the laws of the excluded middle and contradiction to include the existential and universal quantifiers.

Although theoretically simple, this approach in terms of orthogonal arrays rapidly becomes unwieldy to implement on a computer. The aim of the technology of array-based logic is to preserve the mathematical foundation and simultaneously support very large systems in industrial practice [3].

### Computational Aspects of Constraint Satisfaction

In this section we give an overview of existing techniques for solving constraint satisfaction and other intractable problems. Constraint satisfaction is a generalization of the famous *satisfiability* problem that can be stated as follows:

INSTANCE: A set  $U$  of Boolean variables and a Boolean formula  $C$  over the variables in  $U$ .

QUESTION: Is there an assignment of truth-values to the variables in  $U$  that makes  $C$  true?

The computational intractability of this problem was exhibited by Cook [4] when he proved that satisfiability is a NP-complete problem. This means that an efficient algorithm for satisfiability is extremely unlikely although formally no mathematical proof has been given that such an algorithm does not exist.

To practically solve intractable problems, i.e., satisfiability, its generalizations, and other NP-hard problems one usually use methods that can roughly be characterized into two categories.

- Local search methods. These are heuristics for searching the state space in a systematic but incomplete way; hence the obtained solution might not be optimal. The category includes such methodologies as genetic algorithms and simulated annealing.
- Branch and bound methods. These methods make complete searches of the state space by imposing a tree structure on the states and using branch cutting in order to avoid searching branches of the tree that cannot lead to optimality.

We will examine the two categories separately.

#### Local Search

In a local search method we define two functions to each state  $s$  in the state space. A *neighbor* function  $N(s)$  that should be a very small subset of the state space and a *measure* function  $M(s)$  that reflects how well the current state  $s$  conforms to the optimal state. The functions should preferably be easy to compute. As an example consider the three variable instances

$$(a \text{ or } (\text{not } b)) \text{ implies } (\text{not } c).$$

The state space consists of the eight possible rows of a truth table for these variables. If we let  $N(s)$  consist of the set of states that have one of the Boolean variables flipped we get

$$N(0,1,0) = \{(1,1,0), (0,0,0), (0,1,1)\}$$

The measure function should return a real value that gets larger as the current state gets closer to the optimal state. For example, in a conjunction of relations a possible measure would be the number of satisfied relations.

**Hill Climbing:** this method proceeds from an initial state (possibly generated randomly) always choosing the neighbor that has the largest measure and stops when no neighbor increases the measure.

**Tabu Search:** Proceeds almost as Hill climbing except that the selected neighbor with maximum measure is always chosen even if it has lower measure than the current state. The method allows us to exit from local optima but has the drawback that it may continuously alternate between two neighboring states where one is a local optimum. In order to avoid this we maintain a tabu list of the last  $n$  states that have been visited and ensure that we never select a state from this list. Tabu lists typically consist of between ten and fifty states.

**Simulated Annealing:** Here the next state is chosen randomly among the neighbors, thus avoiding the problem of alternation between states with a probabilistic approach. If the selected neighbor has a lower measure than the current state we choose this neighbor as our new state with a probability that diminishes with the number of iterations that the method has performed. This means that at the beginning of the process, the state solutions jump around in the state space, whereas at the end not too much movement is allowed. The analogy being that when the temperature of a metallurgical annealing process diminishes, the molecular structure of the metal fixes itself.

**Genetic algorithms:** Instead of only maintaining one candidate solution state during each iteration of a local search method we can maintain a population of possible candidates, typically in the order of thousands. This leads to a class of methods known as *genetic* or *evolutionary* algorithms. In order to compute new candidates for the next iteration, these methods perform mutation on individual states, which normally corresponds to finding a neighbor in the state space as defined previously, and crossovers between two or more states to generate an offspring state. A selection scheme then selects the fittest individual states, the ones with largest measure, for the next iteration and thus places an evolutionary pressure on the population with the hope that the algorithm should converge to give optimal or near-optimal solutions. The terminology of genetic algorithms comes mainly from biology but there is little, if any, connection between the two fields.

For further reference about local search algorithms and intractability c.f. Papadimitriou and Steiglitz [5].

### Branch and Bound

In the worst case, branch and bound makes an exhaustive search of the state space for a problem. But an ingenious

branch cutting technique can severely reduce the part of the state space that is necessary to consider.

The method proceeds from an initial state and varies one parameter to obtain the children of the state. Each child in turn varies the next parameter to obtain its children and so on.

It is not necessary to generate the complete tree in advance. In fact, for a particular state we evaluate its measure and save the state if the measure is larger than the current maximum. Next, the current state is placed in a queue and one of the children is generated and becomes the current state.

Iterating in this manner traverses the search tree and considers all possible states in the state space.

The branch cut addition to the method compares the current maximum with the state measure and evaluates if any of the children can have larger measure. If they cannot it is not necessary to evaluate these children further and the whole sub-tree can be cut off from the tree. In this way a massive reduction of the number of states that are evaluated can be obtained.

### Implementing Branch and Bound

Realizing a system that uses branch and bound can be done in a number of different ways. One evident way is to explicitly generate the search tree as described above. This is done in most versions of computer implemented two-person games such as chess or checkers. Another way is to specify the parent-child relations using a rule-based system such as Prolog or KEE. In Prolog the branch cut operation is specified by using the  $!$ -operator.

The rest of this paper is dedicated to presenting and illustrating a new computation technique for constraint satisfaction denoted *array-based logic*. The method differs from previously presented methods in that it executes *off-line*. This means that execution is divided into two phases, *preprocessing* and *query* phase. During the preprocessing step the input data is optimized and compressed in such a way as to allow subsequent queries into the data structure to be performed extremely efficiently. This allows us to use the method in real time applications as we illustrate in subsequent examples.

The preprocessing step builds a compact representation of the search tree in a bottom up fashion instead of top down as in previous examples. Using the three operations mentioned in the previous section the search tree is compressed. In this way the operation of equating two axes (operation 2) roughly corresponds to generating the parent state from a set of children and the reduction by logical operations (operation 3) corresponds to branch cutting the tree. Furthermore, the evaluation of state transition is implemented with table look up or indexes referencing.

### Systems in Array-based Logic

A system in array-based logic consists of a set of rules or relations defining the constraints on an ordered set of state variables. In accordance with classical logic, the relations are interpreted as the premises of a logical argument.

The domain of a state variable is an ordered finite set (a list) with  $n$  unique items. The domain  $\{false, true\}$  of a proposi-

tional variable is thus a special case with  $n=2$ . The list may be an explicit representation of all elements in a finite domain, or, in the case of large or maybe even infinite numerical domains, an ordered set of disjoint intervals.

The constraints of the entire system are determined as the conjunction of all relations. The complete state space of a system with  $N$  variables on domains with  $M$  elements may thus be interpreted as an  $N$ -dimensional array with  $M^N$  combinations, each of which can assume either of the truth-values false or not ( $2^N$  combinations in the case of Boolean state variables). The technological challenge is how to represent and manipulate large systems without the expected combinational blow-up in size.

To illustrate, let us consider a simple system on three Boolean variables  $a$ ,  $b$ ,  $c$  and a single relation or proposition

$$R0: (a \text{ or } (\text{not } b)) \Rightarrow (\text{not } c) \quad (1)$$

The truth table of (1) consists of five legal and three non-legal combinations. Thus, the configuration space is not empty and the system is therefore consistent. In the case of large relations with a multitude of legal combinations, it is desirable to compress the tuples into an isomorphic and more compact nested array form. The five legal combinations of (1) in the configuration space are:

$$R0: \quad (2)$$

| $a$ | $b$ | $c$ |
|-----|-----|-----|
| 0   | 0   | 0   |
| 0   | 1   | 0   |
| 0   | 1   | 1   |
| 1   | 0   | 0   |
| 1   | 1   | 0   |

This is carried out by the array operation *compress*:  
Compress R0:

$$(3)$$

| $a$ | $b$ | $c$ |
|-----|-----|-----|
| 0 1 | 0 1 | 0   |
| 0   | 1   | 1   |

The configuration space is now expressed in terms of two Cartesian arguments representing disjoint legal subspaces. The Cartesian product of the first argument (0 1)(0 1)(0) yields four tuples, while the second argument (0 1 1) equals the remaining single tuple in (2). Although more isomorphic representations are possible, the great advantage of the above mentioned array form is that all logical inferences can be computed by just a few arrays operations on the tuples. For example, the state of each variable in the isolated system (1) is deduced simply by computing the unique items in the columns of (2) or (3):

$$SV: \quad (4)$$

| $a$ | $b$ | $c$ |
|-----|-----|-----|
| 0 1 | 0 1 | 0 1 |

The list (4) is termed the state vector. We note that all four state variables are unbounded; that is, they may assume either of the truth-values 0 or 1 (the state of tautology). Thus, there are no constraints on the state variables when the system is isolated from the environment.

The state vector is the important means of interaction between system and environment. Let us assume that variable  $a$  is bounded to true due to external measurements:

$$SV1: \quad (5)$$

| $a$ | $b$ | $c$ |
|-----|-----|-----|
| 1   | 0 1 | 0 1 |

The consequences are determined by joining the input state vector with the system relations (similar to a source on an electrical network or an impressed force in mechanics), and the resulting output state vector is deduced. The reader may verify by visual inspection of (2) that when  $a$  is bounded to true only two tuples of the configuration space are satisfied, and the new state vector SV2 is deduced with  $c$  bounded to false, while  $b$  is still a tautology:

$$SV2: \quad (6)$$

| $a$ | $b$ | $c$ |
|-----|-----|-----|
| 1   | 0 1 | 0   |

In computational practice the state vector transformation (5)-(6) is very fast and even suitable for parallel processing. Note that in contradistinction to the usual IF-THEN rules of expert systems any assignment of variables can be used as input. For example, when  $c$  is bounded to true, we have the following output state vector:

$$SV2: \quad (7)$$

| $a$ | $b$ | $c$ |
|-----|-----|-----|
| 0   | 1   | 1   |

The input state vector may also cause a contradiction. For example, this is the case on the relation (2) when  $a$  and  $c$  are both bounded to true. No tuples are satisfying this constraint. In general, the system constraints will be expressed in terms of more than just a single relation. For example, let us assume that the system (1) is extended with the relation R1:

$$R0: (a \text{ or } (\text{not } b)) \Rightarrow (\text{not } c) \quad (8)$$

$$R1: c \Leftrightarrow d$$

We now have to eliminate the constraints of the individual relations as well as the connectivity constraints caused by the common variable  $c$ . In this simple example, it is possible to join the configuration space of the entire system (the proposition  $R0 \wedge R1$ ) into a single relation:

$$\text{Join } R0 \text{ and } R1: \quad (9)$$

| <i>a</i> | <i>b</i> | <i>c</i> | <i>d</i> |
|----------|----------|----------|----------|
| 0        | 0        | 0        | 0        |
| 0        | 1        | 0        | 0        |
| 0        | 1        | 1        | 1        |
| 1        | 0        | 0        | 0        |
| 1        | 1        | 0        | 0        |

Equating the common *c* axes of the argument relations derives the result (9). This is one of the fundamental array operations termed colligation for making logical inference [1]. The process of joining relations into singles is only possible on a small configuration space; in the case of large systems with a multitude of sparsely constrained relations the configuration space must be expressed in terms of the original relations but still with the connectivity constraints eliminated by colligation [3]. Generally speaking, the EMCON platform supports modeling, analysis, and simulation of large constraint satisfaction problems on the technology of array-based logic sketched above. The major technological requirements are summarized as follows:

1. Completeness: The complete state space with

$M^N$  combinations must be addressable to ensure logical consistency of the entire system. Consistency is very important, especially when security is a critical factor.

2. Compactness: In order to cope with large systems in computational practice, the internal data representation of a system model must be compact yet complete.

3. Real-time capability of simulation: The state vector transformation must be computed as fast as possible with predictable processing time and allocation of memory.

The general form of this transformation is sketched in Figure 1.

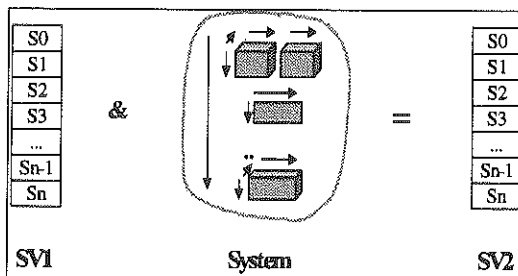


Figure 1. System environment interaction

### Illustrative examples of applications modeled by the array-based technology

Summary of example 1: A wide area protection system, at Sydkraft AB, was the first real-time application of array-based logic. The domain of the system was only 140 variables, all of which are Boolean. Nevertheless, the process of consistency check followed by simulation directly on the consistent data model has proven its value and enhanced the ease of maintenance. Unfortunately the technique was not used in the implementation phase of the project, due to lack of courage and knowledge at that time within the organization. The decided approach to used conventional programming technique failed, due to test and maintenance problems, and the project was

closed. The inherent complexity to handle loss of information, i.e. not defined states or signals due to disturbed communication, in distributed real time systems makes it almost impossible to use conventional programming methods.

Summary of example 2: This example illustrates the array technology applied to power systems, a Ph.D. project sponsored by Sydkraft AB, for creation of complex coupling sequences in a secure and reliable way. The technology enables fast responses during simulation, due to the data driven approach, instead of conventional program driven. The guiding rules for coupling sequences are divided into tactical, functional (e.g. electrical) and operational. The tactical rules are mastered by the operator's skill and therefore not included in the properties of the objects. The functional and operational properties, though, are included, and must be, in order to model safe critical systems. An example is Hemsjö; a medium sized substation in the Nordic power system, where the worst case of deduction takes 97 ms on a 400 MHz PC. The build phase of the substation takes 3.5 minutes and the database encloses 400 KB in compressed form, otherwise 900 KB. The number variables are 1157 (including the interim variables), 586 relations and the free state space covers  $2.2 \cdot 10^{304}$  combinations.

Summary of example 3: By drawing a geometric representation (topology) of a railway station by using a conventional CAE tool, a list of objects (signals, connections etc) can be obtained. By associating each object with a set of predefined constraints, it is possible to automatically derive a list of all possible train routes. Each train route is represented by all the constraints or requirements for that particular train route. In other words, a schedule of all the possible train routes is automatically obtained, including all the requirements for a certain station. An example from a regular station, Borup, in Denmark: The rule base covers 237 KB (compressed), 1062 rules and 3000 variables. The state space covers  $2.1 \cdot 10^{78}$  combinations.

The first two examples are further described below.

### The Wide Area Power Protection System

Svenska Kraftnät, Sydkraft AB and Vattenfall AB have jointly developed a wide area protection system against voltage collapse. [6]. The protection system uses measured analogue and digital values from several power stations and transformer substations, while the logic deduction for coordinated actions in the transmission power system is based on binary created variables. If a measured value or a combination of measured values exceeds a certain threshold, a relay operates. The binary signal may operate a switching device either locally or in a remote station. The logical decision-making process is implemented in the Sydkraft SCADA system. The system wide protection is implemented in three (local control rooms) out of four (central control room) computer system nodes. Specific actions are then ordered from the SCADA system, such as switching of shunt reactors and shunt capacitors, start of gas turbines, request for emergency power from neighboring areas, disconnection of low priority load and, finally, load shedding. Shedding of high priority load also requires a local low voltage criterion in order to increase security. The Swedish transmission system is characterized by a large amount of power transmitted from the



hydro power stations in the North to the load centers in the South. In December 1994 the Baltic Cable 600 MW HVDC link was commissioned from the very South of Sweden to Germany. To be able to use the full export capacity another 600 MW have to be transmitted through the South of Sweden. On the other hand the HVDC link can provide emergency power equal to the difference between the actual point of operation up to 600 MW import (so far the capacity of the cable is limited to 250 Mw caused by limitations on the German AC side). The maximum change of power will probably be limited to 600 MW (presently the limit is 150 MW). Based on the requirements for power transfer through the Baltic Link, the new possibilities provided by using the link for power and the experiences from the temporary voltage controlled load shedding system, it was decided to design a wide area protection system against voltage collapse. The basic power system ideas behind the chosen signals and threshold for creation of the binary signal schemes are given in [6]. The only data used for this special protection system, transmitted in the SCADA system, are the input signals, which are available in all the system nodes. In each node the logic, for actions to be performed in substations controlled by that node, are in continuous operation.

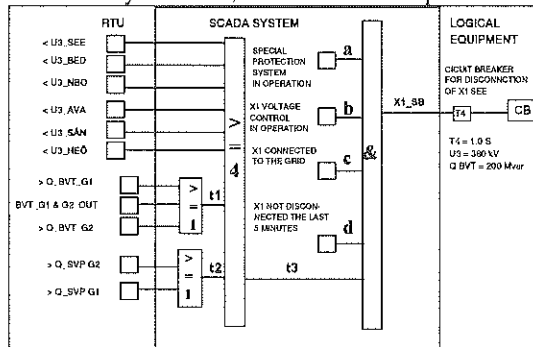


**Figure 2.** Special protection system for disconnection of a 440 kV shunt reactor of 150 Mvar.

The result of the design procedure was a set of logical schemes for each node to control the devices and perform the objectives. One scheme is shown in fig. 2 and will serve as an illustration in this paper. The logical constraints of the protection system in fig. 2 can be expressed solely in terms of binary variables. Table A below defines the logical constraints on the system, while Table B explains the domain of some binary state variables.

**Table A.** System constraints applied to fig. 2.

| #  | Relation                                                                          |
|----|-----------------------------------------------------------------------------------|
| R0 | $t1 = Q\_BVT\_G1 + Q\_BVT\_G2 + (BVT\_G1 \text{ and } BVT\_G2) \geq 1$            |
| R1 | $t2 = Q\_SVP\_G1 + Q\_SVP\_G2 \geq 1$                                             |
| R2 | $t3 = U3\_SEE + U3\_BED + U3\_NBO + U3\_AVA + U3\_SAN + U3\_HEO + t1 + t2 \geq 4$ |
| R3 | $X1\_SB = (a \text{ and } b \text{ and } c \text{ and not } d \text{ and } t3)$   |

Further information is given in [7]. In order to verify and simulate the system, the symbolic form of the relations are compiled into the standard array form sketched in the previous

section. The topology of the logical network in fig. 2 is a simple structure with one output variable X1-SE derived from a given set of input variables. Thus, in this isolated case with just a few variables the consistency of the system is quite obvious and may be verified by visual inspection.

**Table B.** Domain of binary state variables of fig. 2.

| #     | Variable | Explanation                                   | Domain              |
|-------|----------|-----------------------------------------------|---------------------|
| 0     | U3_SEE   | Voltage level in Sege                         | 0: Normal<br>1: Low |
| 1     | U3_BED   | Voltage level in Breared                      | 0: Normal<br>1: Low |
| ..... | .....    | .....                                         | .....               |
| 16    | X1_SB    | Trip signal to circuit breaker X1 SEE in Sege | 0: Off<br>1: On     |

In general, a manual check is not satisfactory. A major advantage of the technology of array-based logic is the capability of automatic consistency verification of the entire system with many interconnected subsystems (distributed systems). The statements, R0 to R3, constitute the program code need to be written in order to describe the functionality of the scheme in fig. 2.

The first step in the modeling process is to establish the standard array form of each isolated relation in Table A. The second step is to eliminate the connectivity constraints defined by the common variables of the relations. This is carried out by colligation, and the result is a complete array form representing the configuration space. When the complete array form has been established, we are ready to perform the state vector transformation on the system. Obviously, traditional programming techniques or even in hardware could deduce the output state X1-SE very efficiently. Why is the array implementation then a better choice as far as a run-time environment is concerned? Firstly, maintenance of the system due to modifications in the system constraints is very easy, when all logic control structures are data rather than something intrinsic to programs. Secondly, the array representation makes it possible to deduce results in either direction, for example the possible inputs implying a given output. Thirdly, the state vector introduced in the previous section includes the states of contradiction and tautology (don't care) as special states of the variables. This is important in the case of missing input signals. For example, if variable b in fig. 2 is unknown due to communication faults, the deduced output X1-SE is also a tautology. Fourthly, the expert can do the programming and simulation according to Table A and the software and real time system experts only embed the application in the SCADA system. No non-application expert is messing up the content of the Array Database, ADB, which is very important when developing safe critical applications. The rest of schemes and variables included in the protection system are treated in the same way.

#### Safe Critical Switching in Power System

The second example illustrates the array technology applied to power systems for creation of complex coupling sequences in a

secure and reliable way.

The technology enables fast responses during simulation, due to the data driven approach, instead of conventional program driven. The guiding rules for coupling sequences are divided into tactical, functional (electrical) and operational. The tactical rules are mastered by the operator's skill and therefore not included in the properties of the objects. The functional and operational properties, though, are included, and must be, in order to model safe critical systems.

The intention is to make an array theoretic as well as a graphical definition of the objects, the primitive properties, in power system network.

After the definition of the primitive properties of the objects, it should be possible to model a part, e.g. a substation or an area, of the network to test the legality and consequences of coupling sequences in that specific area.

#### Topology and variable representation

Graphs are often a very efficient way to model a system containing topological information. Some graph models can be close to the system i.e. the topology of the graphs can easily be identified in the physical system. In others, the topological data can be more or less hidden in the system.

For systems like power and railway systems, at least one set of topologic information is obvious. The system itself is a network of topological information. The diagram of an electric network is an example of a model with topological data that can be found directly in the physical system. The topology of an electric diagram is isomorphic to the physical system.

The Roth diagram of electrical systems is an example of a model that is not isomorphic to the physical system. This diagram constitutes the formulation and solution of the electric network problem. Since the topology of Roth diagram is based on Ohm's and Kirchhoff's laws of resistive electric networks the topology of Roth diagram is not isomorphic to the physical system.

In order to handle safe critical applications in an electrical network, the definition of a minimum set of variables and graph representation is crucial. In [8] it is shown that an optimal representation is to use both voltage and current as compound variables.

When connecting two electric elements it is equivalent to make two colligations: voltage and current. Often it does not make sense to connect two voltage variables without also connecting two current variables. If this should be reflected graphically, an electric stub, "p" should be added representing both a voltage and a current. Using a nested type of variables, containing both voltage and current, achieve this. This nested representation of variables is supported by the array database in the form of "compound identifiers". The new definition and extended colligation graph is shown in fig. 3. Now the graph and the electric diagram are isomorphic, and this makes it easier to model the electric network, [9].

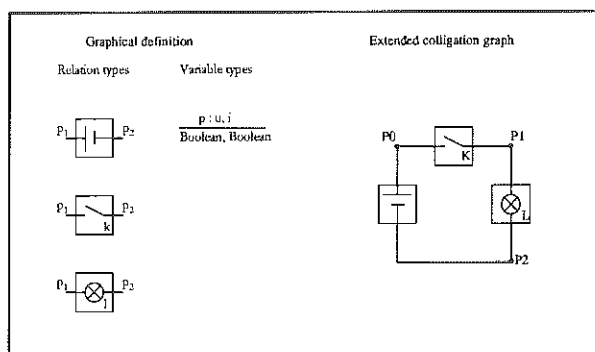


Figure 3. Graphical definition and extended colligation graph

#### Definition of the electrical objects

All the objects included in a general coupling sequence have to be modeled according to its specific set of rules. In order to achieve this, a proper choice of the domain of the variables, associated to each object, have to be defined.

Two different and conflicting guidelines are important when deciding a proper domain of a specific variable.

- 1) The larger the domain, the more accurately the physical variable is described.
- 2) The smaller the domain, the smaller the resulting array database and bigger systems can be built.

This means that the domain of a variable must be large enough to describe the physical quality of the variable in an adequate way, but no more.

The states of a circuit breaker can be described by five variables. Two voltage signals describing the terminal voltages. Two current signals describing the current flow in the two terminal and one of a binary type, that describe whether the breaker is open or not, see Table C. Following variable definition is used in the case of breakers. The two current variables are marked as interim because these variables will be eliminated in order to reduce the database, but needed during the modeling phase or description of safe critical properties of the breaker.

Table C. Circuit breaker variables and domain.

| Variable | Explanation | Domain                                       |
|----------|-------------|----------------------------------------------|
| BPos     | input       | (SwOff, SwOn)                                |
| U1       | output      | (Voltage, NoVoltage, Disconnected, Grounded) |
| U2       | output      | (Voltage, NoVoltage, Disconnected, Grounded) |
| I1       | interim     | (In, Out, NoCurrent)                         |
| I2       | interim     | (In, Out, NoCurrent)                         |

These domains give a state space of 288 possible combinations. The major part of the logical definition consists in dividing the possible combinations into legal and illegal combinations. By inspecting the rules regarding the breaker defines the legal combinations. Both electrical and coupling rules must be examined.

### Electrical rules of a breaker

1. No current can flow through an open breaker.
2. No current can flow if not both voltage variables are Voltage.
3. If the current at one terminal is "In", the current at the other must be "Out".
4. If no current is flowing at one terminal, no current can flow at the other terminal.
5. If the breaker is closed, there cannot be voltage at one terminal and no voltage, disconnected, or grounded at the other terminal.

### Coupling rules of a breaker

The breaker cannot be used as disconnector, i.e. if there is voltage or no voltage at one terminal, the other terminal cannot be disconnected or grounded even if the breaker is open.

### Legal combinations of a breaker

After the rules have been examined and the illegal combinations are found, the combinations in Table 1 remain as legal. These combinations can be verified that they not violate any of the rules. The number of legal combinations turns out to be 16 and constitutes the primitive description of a circuit breaker. This table can now be written to a text file and made accessible to the build tool of the array database software.

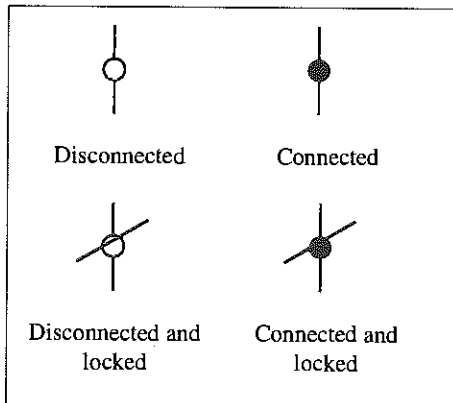


Figure 4. Disconnector symbols

### Disconnector

The disconnector symbol is shown in fig. 4. The conditions for a disconnection is a visual gab between the two terminals and that the disconnection is locked. The disconnector can fulfil both these demands. However, it cannot be used to break current under normal circumstances.

### Logical definition of a disconnector

The rule regarding the breaking of current says that if a load current is flowing, the next position of the disconnector must

not be disconnected. This means that the next position of a disconnector must be represented by a variable. Table D shows the variables and the domains.

| pos   | i1        | u1           | i2        | u2           |
|-------|-----------|--------------|-----------|--------------|
| SWON  | IN        | VOLTAGE      | OUT       | VOLTAGE      |
| SWON  | OUT       | VOLTAGE      | IN        | VOLTAGE      |
| SWON  | NOCURRENT | VOLTAGE      | NOCURRENT | VOLTAGE      |
| SWON  | NOCURRENT | NOVOLTAGE    | NOCURRENT | NOVOLTAGE    |
| SWON  | NOCURRENT | DISCONNECTED | NOCURRENT | DISCONNECTED |
| SWON  | NOCURRENT | DISCONNECTED | NOCURRENT | GROUND       |
| SWON  | NOCURRENT | GROUND       | NOCURRENT | DISCONNECTED |
| SWON  | NOCURRENT | GROUND       | NOCURRENT | GROUND       |
| SWOFF | NOCURRENT | VOLTAGE      | NOCURRENT | VOLTAGE      |
| SWOFF | NOCURRENT | VOLTAGE      | NOCURRENT | NOVOLTAGE    |
| SWOFF | NOCURRENT | NOVOLTAGE    | NOCURRENT | VOLTAGE      |
| SWOFF | NOCURRENT | NOVOLTAGE    | NOCURRENT | NOVOLTAGE    |
| SWOFF | NOCURRENT | DISCONNECTED | NOCURRENT | DISCONNECTED |
| SWOFF | NOCURRENT | DISCONNECTED | NOCURRENT | GROUND       |
| SWOFF | NOCURRENT | GROUND       | NOCURRENT | DISCONNECTED |
| SWOFF | NOCURRENT | GROUND       | NOCURRENT | GROUND       |

Table 1: Legal Combinations for a circuit breaker

Table D. Disconnector variables and domain.

| Variable | Explanation | Domain                                       |
|----------|-------------|----------------------------------------------|
| NextPos  | output      | (SwOff, SwOn, SwOffLock, SwOnLock)           |
| Pos      | input       | (SwOff, SwOn, SwOffLock, SwOnLock)           |
| U1       | output      | (Voltage, NoVoltage, Disconnected, Grounded) |
| U2       | output      | (Voltage, NoVoltage, Disconnected, Grounded) |
| I1       | interim     | (In, Out, NoCurrent)                         |
| I2       | interim     | (In, Out, NoCurrent)                         |

The next position variable makes the disconnector a dynamic primitive according to chapter 10.4, [8]. Of course, the current position of the disconnector must also be represented. The two position variables form a dynamic variable. Apart from the two position variables, two sets of voltage and current variables are needed. This variable definition gives a state space of 2304 possible combinations.

### Electrical rules of the disconnector

1. No current can flow though a disconnected disconnector.
2. No current can flow if the voltage variables are not Voltage.
3. If the current in one terminal is In, the current in the other must be Out.
4. If no current is flowing in one terminal, no current can flow in the other.

5. If the disconnector is connected, there cannot be Voltage at one terminal and NoVoltage, Disconnected, or Ground at the other.

#### *Coupling rules of the disconnector*

1. The disconnector cannot be used to break load current or charging current when connected to a long, remote open end, line. If a load current is flowing, the next position cannot be disconnected.
2. The disconnector must be unlocked before it is operated. If the current position is "disconnected and locked", the next position must remain "disconnected and locked" or changed to "disconnected". This is also the case for "connected and locked".
3. It is not legal to ground through a disconnector if it is not connected and locked.
4. An area cannot be considered disconnected before the disconnector is locked.

#### *Special situations*

In some rare situations, it is legal to break current using a disconnector. This may only be done if a parallel connection exists, i.e. commutation of current.

After the rules have been inspected, 90 legal states of the disconnector remain.

The same procedure is repeated for all the objects (transformers, ground connectors etc) in order to define the legal combinations needed for modeling.

### **Modeling of power system**

After the definition of the primitives a regular substation can be modeled. Normally one or more stations are involved in a coupling sequence. In the following, the station Bäckaskog will be modeled. The normal coupling diagram of Bäckaskog, a CAD-drawing from Sydkraft AB, is shown in fig.5. During the simulation and the building phase of the substations a software package named, G2, was used. Gensym Inc., USA, develops the G2- software. G2 is an object-oriented expert system with real time capability and off-line simulation. In order to build a general part of a power system a special library including all coupling objects was developed. All the coupling sequences start normally from a predefined state.

The normal coupling situation is automatically loaded when G2 is started and the workspace of the station is shown. To define the normal coupling topology in G2, the model is changed until it is identical to the normal coupling situation. Then the "Save as Normal Coupling" - button is pressed.

An example of a coupling sequence is described below.

The normal coupling schematic for Bäckaskog is loaded into a workspace in G2. The T2 transformer supplies both the 10 kV busbars, while the T1 transformer is idle.

The goal of this coupling sequence is to prepare the cable between the transformer T2 and the breaker, O10, for maintenance.

After the work is done the coupling sequence must bring the station back to normal coupling.

Obviously, the supply of the 10 kV busbars must be moved to T1 while the maintenance work is going on. In addition, the cable must be grounded before the area can be released for maintenance. The first step is to connect T1. The primary side of the transformer must be connected first. Connecting the disconnector F52S does this.

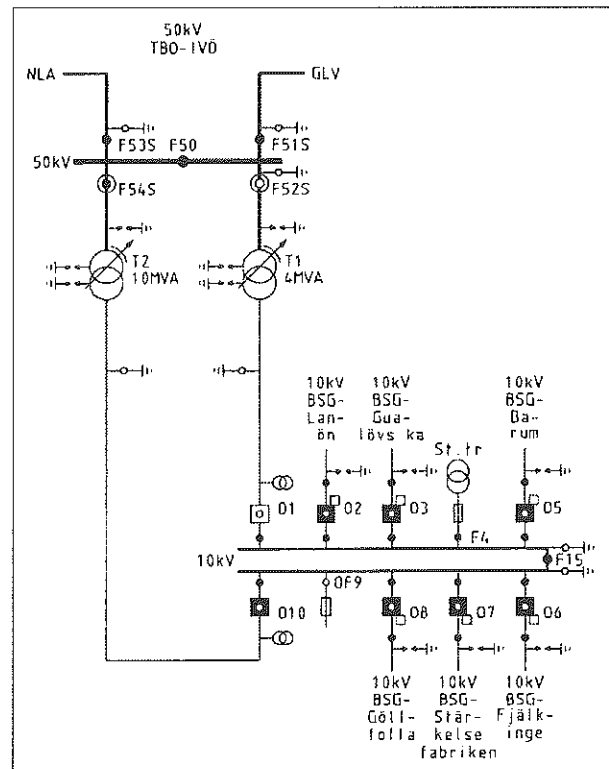


Figure 5. Bäckaskog. Normal coupling conditions

In the G2 model the "switch on" menu point at the pop-up menu is selected. The pop-up menu, shown in fig. 7, appears when the disconnector is selected.

| Disconnector 50 kV   |
|----------------------|
| Lock in off position |
| Switch off           |
| Switch on            |

Figure 7. Pop-up Menu

The array database is automatically consulted to check if the coupling is legal. If it is, the consequences of the coupling are retrieved from the array database and are directly shown in the scheme. The levels of the 50 kV cable to the transformer and 10 kV cable from the transformer are changed to "VOLTAGE" and changing the color of the two cables shows it. Now the transformer must be connected to the busbars. Closing breaker, O1, achieves this. After the coupling, the 10 kV busbars are supplied from both the transformers.

It is now possible to break the supply from the T2 transformer without affecting the power supply to any customer. The breaker O10 is opened in order to achieve this. The disconnectors F54S and F10S can then be disconnected in order to isolate the area. The color of the cable is changed to black, which shows that no voltage is applied to the cable.

Now the user commits an error that violates the rules of coupling. Having isolated T2 and the cable connections to it, the operator believes that it is legal to close the ground connector between T2 and O10. Electrically this operation causes no problem because the area is without voltage. However, the operation violates one of the security rules. It is not legal to ground an area before it is isolated and locked in this state. The problem is that none of the two disconnectors is locked. Having neglected the detail about locking the disconnector, the operator tries to connect the ground connector.

The array database is consulted to ensure that the operation is legal. The answer from the array database is an error code and a text explaining that the operation causes a contradiction. The user is notified and the operation is ignored. F54S and F10S are then locked in the disconnected state in order to fulfil the rules. The G2 model is updated by changing the icons of the two disconnectors.

The color of the cables is also changed. It is now cyan to show the operator that the area now is isolated and locked. Now it is legal to connect the ground connector.

The color of the cable between the transformer T2 and the breaker O10 is changed to green. This tells the operator that the cable is now grounded, and the maintenance work can begin. The little piece of cable between O10 and the locked disconnector is still cyan. This indicates that this site of the breaker cannot be considered grounded. Even if the breaker were closed, the cable would remain cyan, because it is not legal to ground through a breaker. The same thing can be observed with the cable between T2 and F54S.

The last item in this part of the coupling sequence is to send work permission regarding the 10 kV cable between T2 and O10 at BSG. The couplings must not continue before operation permission is received from the maintenance worker at BSG. When the maintenance work is finished and the operation permission is received, the couplings can continue in order to bring the station back to normal coupling. These couplings are not shown here.

The extended colligation graph contains all the information needed to build an array database. The relations are defined as ties binding the variables together. The nodes in the extended colligation graph represent the system variables. Different types of ties can be defined in a way that makes it easy for the user to identify the primitive type it represents. This is called the graphical definition. The logical definition of a primitive holds the restriction of the variable combinations. It can e.g. be given in form of a logical table. When the primitives are defined, it must be possible to validate the expert rules and determine if it is legal or not. Afterwards different primitives can be combined into new primitives.

Of course, it is necessary to have some knowledge of array-based logic in the primitive definition phase. The primitives are simply combined in their graphical form and the input to the

array database is automatically generated with *no risk* of errors. This modeling method is best used on systems with some build-in topological information e.g. electric networks or railway system. In addition, the primitives should be defined in a way that makes the diagram of the system and the extended colligation graph isomorphic. If they can be made isomorphic, drawing a diagram of the network using the defined primitives and a graphical platform like e.g. G2 constitutes the modeling of the system.

When the graphical and the logical definition of the primitives are finished, connecting the primitives according to the physical system generates the array database. A person without knowledge of array-based logic can do this process. To make the modeling phase easy, a graphical building tool must support it. In this project, G2 from Gensym Inc. is used as graphical tool both during the modeling phase and later during the simulation. G2 offers the opportunity to build the model by making instances of the defined primitive. The primitives are then placed on a workspace and connected to reflect the physical system. The input text file is automatically generated by G2. Afterwards the build tool within the array database is automatically called by G2 and a binary array database is built. The operator is of course warned if any problems occur during the building of the binary array database, or if it turns out that the database is inconsistent.

## Conclusion

None of the methods described can, accept the array logic technique, handle complex constraint logic problems in real time, as far as we have tested. The completeness problem can be handled by other methods. Only the array logic methodology uses a data driven approach, i.e. the time consuming completeness problem is solved off-line and a consistent and compact data base is loaded into the target system. Further more, the states or the variables are considered as physical measurements and the state transition or deduction is carried out by a simple table look-up technique, which is extremely fast. As shown in example two, [8], it is possible to generate the database automatically, which is important when safe critical systems are concerned. The expert defines the primitive rules for the system objects and the graph constitutes the complete system. No programmer can by this technique mess up the system behavior. The expert will get what he sees on the graph. Different types of simulations and checks can be made on the array database. The most fundamental is the consistency check, which is performed during the building of the binary array database. The check ensures that the model has at least one legal variable combination. Normally an array database model has several legal variable combinations, but configuration problems with only one legal solution exist. In these, the task would be to identify the legal combination. Even though the model has more legal combinations, some of the variables could be bound to specific values. These values can be identified by the array database and shown in e.g. the G2 model. Another type of simulation is the validation of a model. By enabling some of the variables to be bound and a deduction can be made on the remaining variables. It is thereby possible to

validate that the model is working as expected. Since no distinction is made between input and output variables in this simulation, it is possible to bind variables that are normally considered output to deduct the input that would generate this output. This type of simulation is shown in [8].

Although the technology at the present stage makes it possible to cope with propositional logic, predicate calculus, and relational algebra on one nested array form, the scope is limited to static constraints. The future development will therefore focus on dynamic or time dependent systems, state-event processing, discrete optimization.

The technology is also suited for parallel processing, which makes it possible to model and simulate a complete system and then distribute different parts of it to other computer systems. The functionality of the system as whole is hereby secured.

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## A Multiagent Approach for Secure Operation of FACTS

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### Abstract

The implementation of novel power-electronic FACTS devices offers many advantages concerning a flexible operation of modern liberalized electrical power systems. However, during their operation they cause some negative effects affecting the steady-state and dynamical system security. The paper describes the necessary co-ordinating control measures which are required to suppress these negative effects and to ensure a secure operation of FACTS. It introduces the theory of autonomous systems as a schematic multiagent approach to realize such a preventive co-ordinating control. In a first step the co-ordinating measures are represented in a universally valid knowledge-based form. This generic representation must be related to each FACTS device in its environment dependent on the network topology. Therefore the autonomous control system automatically analyses the topology of the power system and generates specific information, like fuzzy rule bases e.g., from the generic knowledge-based representation of the co-ordinating measures. The specific information is downloaded into decentralized autonomous agents which co-ordinate conventional controllers and FACTS-controllers. The generic co-ordinating measures remain valid with a change of the network topology, but the specific information has to be adapted to the new topology. For this reason, the multiagent control system reacts automatically to changes of the network topology and updates the specific information.

### Keywords

FACTS, FACTS control, co-ordinated control, autonomous multiagent systems, preventive control, steady-state and dynamical system security, fuzzy adaptation

### 1. Introduction

The worldwide trend towards the liberalization requires electric power systems with a defined reliability under uncertain future operating conditions and scenarios. It also requires an increase of the exploitation and flexibility of existing systems. Independent of this, several technical restrictions as e.g. congestions, loop flows, inadequate fault tolerances, and stability limits affect an efficient use of today's power systems. Against this background the application of new power electronic devices in electrical power systems becomes increasingly attractive. These devices are familiar under the name "FACTS devices" (FACTS - Flexible AC Transmission Systems) and enable an expanded controllability of the system [1].

Features, structure, and control of FACTS devices are described more closely in section II. At this time FACTS devices are in many cases still in the development phase. However, first prototypes of FACTS devices are already in use for system studies [2]. They enable interventions into the system in the short-term range and are implemented for fast power flow control, for voltage control as well as for the improvement of stability [3]. Nevertheless the use of FACTS devices in power systems causes the following problems which have to be solved:

The response time of FACTS devices is in the range of some ten milliseconds. In case of critical events within the power system, e.g. faults or overloadings, FACTS devices react immediately to these events due to their short response time. As the FACTS devices are not adapted to the new situation after such a critical event, this can lead to an endangerment of the steady-state and dynamical system security [4, 5].

As a consequence, the application of FACTS devices requires both a fast co-ordination of their controllers among one another and with power plants, loads, and conventional controlling devices within the power system. This co-ordination must guarantee the steady-state and dynamical system security in the case of critical events and has to be automatic, quick, intelligent, and preventive.

The solution presented here is a co-ordinating multiagent control system. Section III describes the theory of autonomous systems for the development of multiagent control systems [6]. Autonomous systems represent an abstract information-technological framework which is specified in this paper for the co-ordinated control of FACTS devices.

In Section IV the necessary co-ordinating measures in any power system are explained in detail. They can be expressed qualitatively in the form of generic rules which represent general actions and which are not formulated device-specific [7].

Section V contains the realization of the multiagent control system. The necessary co-ordination is carried out on the one hand with fuzzy modules which intervene adaptively into the local FACTS-controllers. Different controllers can also be activated or deactivated by this fuzzy adaptation. On the other hand additional outer control loops are proposed to perform co-ordination by changing the setpoint values after the occurrence of critical events.

The operating states and the topology of the power system continuously change in the daily operation through the varying loads and switching operations. The co-ordinating control measures must be followed up automatically to these changes. Only under this condition the fuzzy modules and additional outer control loops are able to react adequately on critical events in the changed system, so that a dynamical and stationary secure behaviour of the whole system can be guaranteed

even here. Hence, topology-changes of the network have to be analyzed continuously. This continuous adaptation to changing topologies is called “preventive co-ordination” [4] being performed by the multiagent control system. Section VI gives examples for the application of the multiagent system, which are verified by dynamic simulations of an example power system. In comparison to the state of the art the method proposed in this paper is a basic new approach. In the past controllers for FACTS devices with different tasks are globally parameterized, but only for the normal operation and a fixed network topology [8, 9]. Therefore, the reaction on critical events is insufficient and maloperations and an endangerment of the system security can arise as soon as the power system is transferred into a different operating state.

The work presented in this paper is a further development of [10].

## II. FACTS devices

### Features

FACTS devices offer an expanded controllability of power systems through their electrical characteristics of shunt- and/or series-compensation and phase shift control, which is realized through fast current-, voltage-, and impedance-control. An essential element of FACTS devices are power electronic components which enable a very short response time in the range of a few ten milliseconds [11].

FACTS devices are employed for load flow control, voltage control and the improvement of stability [3]. The UPFC (Unified Power Flow Controller) is a universally applicable FACTS device, because it combines the characteristics of most of the other FACTS devices [12].

### Structure

The electrical characteristics shunt-/series compensation and phase shift control are realized through the application of modern power electronics together with a shunt- and a booster-transformer [11].

The structure of FACTS devices can be schematically illustrated by quadripoles [13]. Fig. 1 shows the structure of the UPFC as a serial-parallel FACTS device. The two voltage-sourced switching converters ( $VSC_p$  and  $VSC_s$ ) are connected to the shunt- resp. the booster-transformer and are linked with a d.c.-component, which is represented by a capacitor. In serial FACTS devices there is only one transformer in the series branch, in parallel ones accordingly only one in the shunt branch.

### Modelling and Control

Through its local operating point controllers a UPFC is able to control active- and reactive-power flow on the transmission line, to which it is installed in series, and the nodal voltage at one of its connection-points. Usually these three controllers are implemented as PI controllers. They receive setpoint values for the active- and reactive-power flows  $P_{ij,ref}$ ,  $Q_{ij,ref}$  and node voltage absolute values  $V_{i,ref}$  resp.  $V_{j,ref}$  at the connection points of

the UPFC. The manipulated variables of the three controllers are the real and the imaginary part of the longitudinal voltage  $V_l$  to be impressed, and the absolute value of the shunt current  $I_q$  which has to be injected. From these manipulated variables and further local measured values of the UPFC, such as the DC voltage  $V_{DC}$  or the voltage angle of  $V_l$ , the converter control determines the trigger angles for the GTO-Thyristors of the two VSC and generates impulses for their activation. Furthermore, it keeps the limits of the manipulated variables. In this way the shunt and the booster transformer generate the necessary voltage resp. current in order to keep the setpoint values.

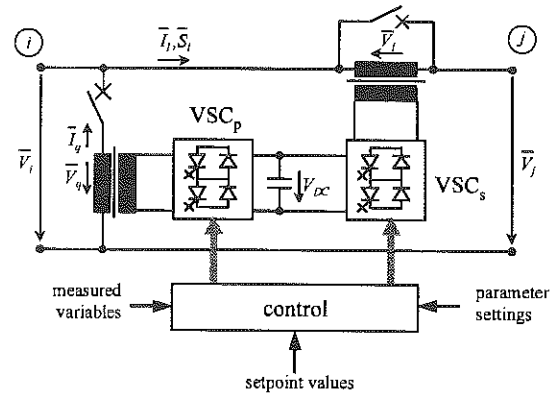


Fig. 1: Schematic structure of a UPFC

As shown in fig. 2 the UPFC itself can be modelled by a current source injecting the shunt current  $I_q$ , a voltage source impressing the longitudinal voltage  $V_l$  and a serial reactance  $X_{UPFC}$ . The behaviour of the two VSC is modelled by a first order time delay with a time constant  $T_c$  which lies between 15 and 30 ms [14].

Furthermore controllers for stability impact (small-signal-stability and transient stability) can be present. They are usually implemented to work in parallel to the operating point controllers (see fig. 2) but will not be further considered here.

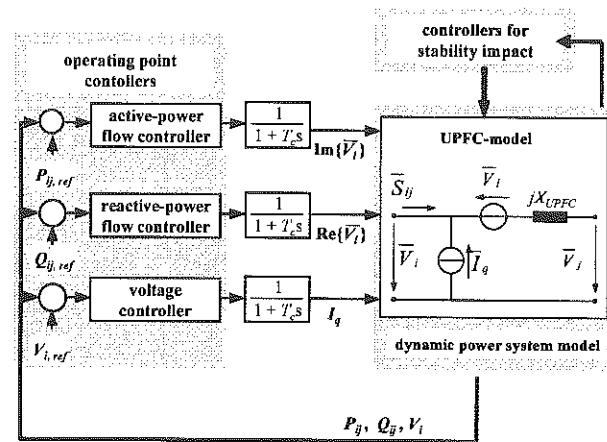


Fig. 2: Controllers of a UPFC



### III. Multiagent Control Systems

An autonomous multiagent control system is a control unit of a technical system. Generally its architecture can be subdivided into several intelligent autonomous agents communicating with each other. The autonomous agents themselves consist of different authorities called 'management', 'co-ordination', and 'execution'. Depending on the control level on which an intelligent autonomous agent is placed, one of the three instances dominates compared to the other two instances. In order to specify the agents on each control level every necessary local controller of the process must be determined concerning its structure. An autonomous agent can be a control station, a process computer or a simple controller.

The control level on which an agent is placed also determines the main functionality of the agent. In [6] a general concept of autonomous control systems is presented consisting of several intelligent controllers working in parallel and independently. This concept can be adapted to a more flexible architecture of autonomous control systems in electrical power systems [10]. According to the hierarchical model of an instrumentation system for complex technical processes, e.g. an electric power system, the different control levels are called:

- network control level,
- substation control level,
- bay control level.

This leads to the structure of the system shown in fig. 3, where the actuators can be represented by FACTS devices e.g.

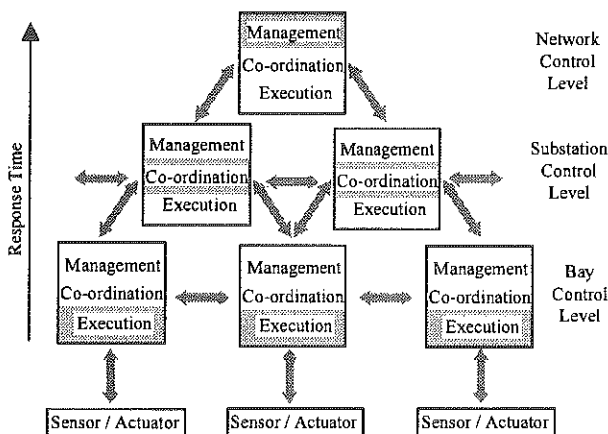


Fig. 3: Multiagent control system

**Bay Control Level:** The physical coupling of the autonomous agents on the bay control level is realized by sensors and actuators. The main task at the bay control level is 'execution', i.e. in this context mainly the application of control and adaptation algorithms.

**Substation Control Level:** Autonomous agents on the substation control level mainly act as co-ordinators. They determine and

plan the functionality of other components and delegate distinct special tasks.

**Network Control Level:** On the system control level autonomous agents are working with information being generated from a model of the process which can be implemented on this control level. The most important task of these components is the decomposition of global aims being generated here or prescribed by a human operator through the human-machine-interface.

This theoretical concept of autonomous multiagent systems is independent of the kind of physical process. It leads to the following features and advantages of those systems:

- They can perform self-learning, self-organization, and can plan and optimize control actions.
- Artificial intelligence can be arranged decentrally. This enables quick autonomous intelligent actions.
- Multiagent systems can adapt themselves automatically to changes of the technical process in structure and parameter.
- The operation of the process can be performed without the need of human intervention or monitoring.

Consequently, faults can be localized quicker, the exploitation of the process will be increased, the adaptability of the whole system will grow, and reaction times as well as data flows between decentral units and the control center will be reduced.

### IV. Co-ordination

System studies of FACTS [4, 5] have shown that their technical advantages as mentioned before can only be utilized profitably in connection with a purposeful extension of the control and protection system. The dynamic behaviour of the power system gets worse and an endangering of the steady-state and dynamical system security is to be expected with an inadequate adaptation of the control operations by FACTS devices to changing operating situations or critical events in the power system.

Therefore, the structure of autonomous multiagent systems as an information-processing concept for the co-ordinated control of FACTS devices has been proposed as an extension of the control and protection system in power systems [10].

In the following, concrete critical events which require co-ordinating control measures to be applied to the embedded FACTS devices are listed:

- overloading of electrical devices
- failure of electrical devices
- short circuits in transmission elements

The necessary co-ordinating control measures have to be realized by the autonomous control system. They have to be applied in short term range after the occurrence of one of the above mentioned critical events. They can be formulated in a knowledge-based form as so-called generic rules [7]. Before they will be listed and explained, the definition of two terms which concern the network topology is necessary according to table 1. To explain this, the topology of the example system

which is used in the following is shown in fig. 4. Generators are named with G, loads with L and UPFC with U.

Table 1: Definition of terms

| Term          | Definition                                                                                                                               | Examples                                                                                     |
|---------------|------------------------------------------------------------------------------------------------------------------------------------------|----------------------------------------------------------------------------------------------|
| control path  | transmission path in which a power flow controlling device (e.g. UPFC) is implemented and which only has junctions at its end-nodes      | 18-5-6-7<br>14-15-16-17<br>7-9-10-11                                                         |
| parallel path | transmission path which starts and ends at the same nodes as a control path and in which no power flow controlling device is implemented | 18-17-7<br>is a parallel path of 18-5-6-7<br>14-19-7-17<br>is a parallel path of 14-15-16-17 |

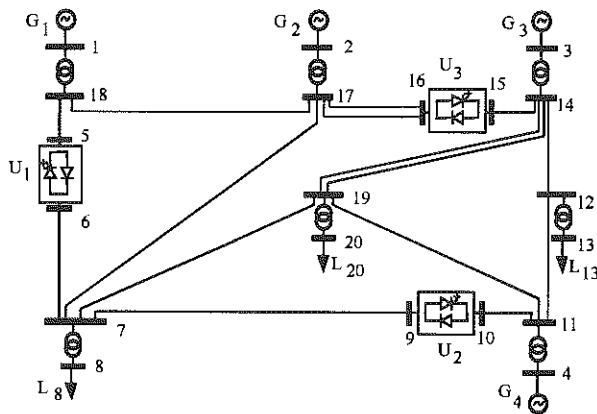


Fig. 4: Topology of the test system

The following three co-ordinating control measures shall be treated by a multiagent control system:

1. **IF** a device on a parallel path of a FACTS device is overloaded,  
**THEN** modify the P-setpoint-values of the FACTS- device

A power-flow controlling FACTS device can directly influence the active and reactive power flow on its control path. This leads to a shift of the power flow from the control path to parallel paths resp. vice versa. Consequently, power flows on parallel paths can be specifically influenced by changing the set-point values for active- and reactive-power flows of the control path. In this way overloadings of devices on parallel paths can be suppressed by changing the setpoint values of a power-flow controlling FACTS device. The control path takes over the surplus of power flow which otherwise leads to the overloading of the device(s) on a parallel path.

This rule recommends to modify only the P-setpoint-values of FACTS devices to suppress overloadings because these are

mainly caused by active power flows. The reactive power-flow controlling functions of a FACTS device can then be used for voltage control.

2. **IF** there is a failure of a device on a parallel path **AND** no further parallel path exists for a FACTS device  
**THEN** deactivate the power flow controllers of the FACTS device

The existence of at least one parallel path to a control path is an important condition for the reasonable application of a power flow controlling FACTS device. As already described above, power flow control causes a shift of the power flow between control path and parallel path(s). Hence, if a failure of a device causes an opening of all parallel paths, the power flow control of a FACTS device is hindered. The consequence would be that the manipulated variables of the FACTS device's power flow controllers would run into their limits, which may cause strong system oscillations. By deactivating the power flow controllers after such a failure this can effectively be prevented.

3. **IF** a short circuit happens on a control path or on a parallel path of a FACTS device,  
**THEN** slow down the operating point controllers of the FACTS device

This co-ordinating measure prevents excessive power oscillations after a short circuit followed by automatic reclosing. The reason for this is that the power flows change strongly during the short circuit. Mainly, a high reactive current flows on all lines into the direction of the short circuit location. Because of the short response time of the FACTS devices the power flow controllers respond immediately and try to meet the preset set-point values. Also the voltage controller tries to fix the set-point-voltage. Hence, the manipulated variables of the operating point controllers are strongly increased within a short period of time and reach their limits even before the fault is clarified and the automatic reclosing is started. When the fault is removed after an automatic reclosing these large values of the manipulated variables of the power flow controllers lead to strong oscillations. Through slowing down the power flow controllers and the voltage controller during the short circuit and the automatic reclosing (decreasing of the PI controller-parameters) this effect can effectively be prevented.

## V. Realization of the Multiagent Control System

The three co-ordinating generic rules which have been explained above are the elementary tasks which have to be fulfilled by the multiagent control system whose development is described in the present section.

### Bay Control Level

The realization of the multiagent control system is started on the bay control level. Figure 5 shows the operating point controllers of a UPFC which are extended by additional controllers

as autonomous agents on the bay control level. They realize the basic measures which are given by the three generic rules.

The co-ordinating measure given by the first generic rule is realized by an integral-action controller forming an outer control loop. It adjusts the setpoint of the active-power flow controller in order to suppress overloadings of transmission lines on parallel paths. In case of several overloadings the biggest overloading is chosen and the integral-action controller modifies the setpoint for the active power flow until the overloading is removed. It reduces the active power flow of the chosen element being overloaded to its maximum capacity  $P_{max}$ .

The second generic rule requires a deactivation of the power flow controllers in the case of failures of distinct devices on parallel paths. The deactivation of the controllers is performed by fuzzy module 1, which sets the controller parameters of the active and reactive power flow controller to zero. Such a fuzzy adaptation produces soft transitions between the activation and deactivation of the controllers and provides a transparent implementation of the knowledge bases which are derived from the generic rule 2. This will be described below. The input quantities of the fuzzy controller must be measured values of lines on parallel paths. From these input quantities the fuzzy controller must be able to clearly recognize failures of transmission elements. Measurements of the currents or complex power flows over the concerning transmission elements can be taken as input quantities.

The implementation of the third generic rule on the bay control level is also done by a fuzzy controller performing an adaptation of controller parameters (fuzzy module 2). It reduces the operating point controller's parameters in cases of short circuits on lines on the control path or on parallel paths so that the controllers are slowed down strongly. Faults must be reliably recognized by the input quantities of the fuzzy controller. Hence, the currents over those lines can be taken as input quantities for the fuzzy controller e.g.

#### Substation and Network Control Level

Autonomous agents on the substation and the network control level have to generate specific information for the fuzzy modules and the integral-action controller (see fig. 6). This must be based on the three generic rules. At first the network's topology has to be analyzed automatically. This is done recursively with backtracking technique. The result is an assignment of all parallel paths to each control path. For large and complex networks these calculations can take long computation time. With the result of the topology analysis the three generic rules can be brought to a set of concrete co-ordinating rules which are valid for the actual network topology.

These rules are then translated by autonomous agents into fuzzy rule bases for the fuzzy modules 1 and 2 on the bay control level for each FACTS device. The rulebases are downloaded into the fuzzy modules. Several investigations have shown that fuzzy sets can be individually chosen for the network and remain valid for each topology situation [5].

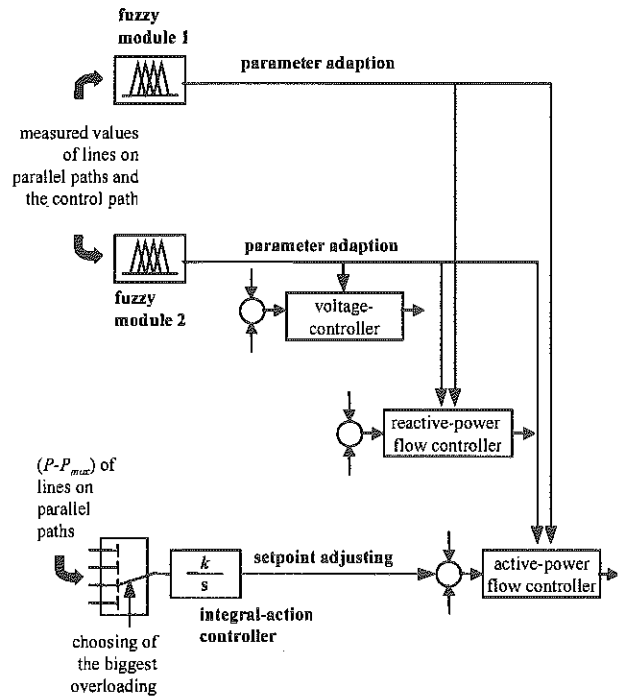


Fig. 5: Operating point controllers of a UPFC with autonomous agents on the bay control level

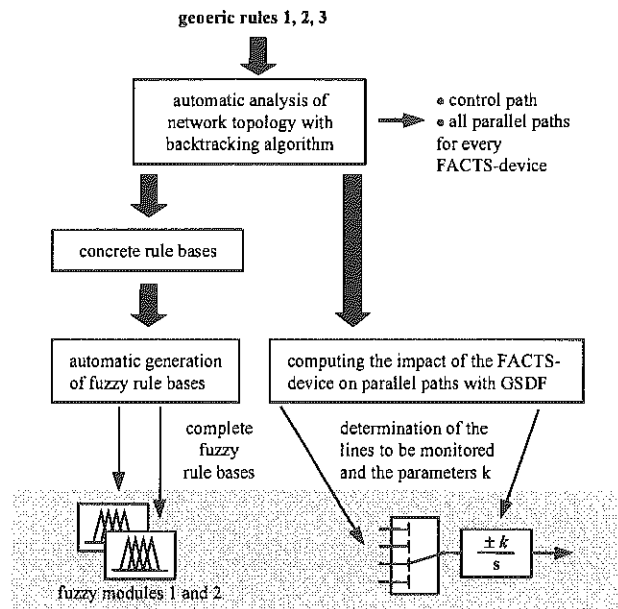


Fig. 6: Additional autonomous agents on the substation and network control level

Concerning the first generic rule the result of the topology analysis is used by another autonomous agent to compute the

impact of the FACTS devices on lines on parallel paths. It computes the GSDF (generation shift distribution factors, [15]) in order to quantify the impacts on all relevant lines. The GSDF determine the lines which have to be monitored with regard to overloadings and they determine the parameters  $k$  of the integral-action controllers. In this way it can be guaranteed that the integral-action controllers perform their control actions to remove overloadings with the correct direction and the necessary intensity.

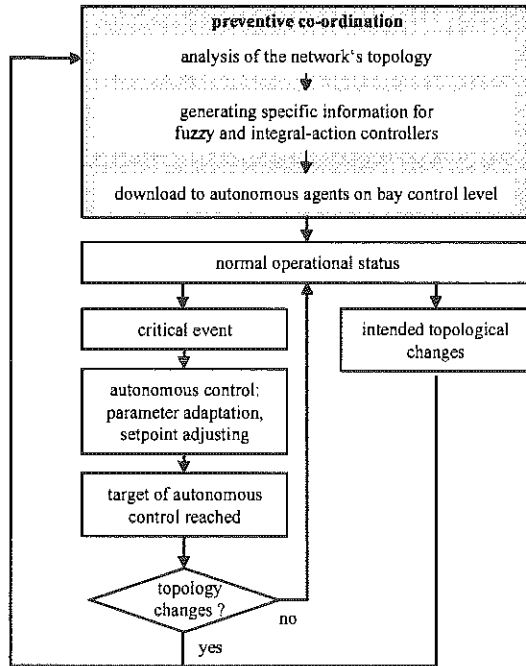


Fig. 7: Procedure for preventive co-ordination of FACTS devices

#### Preventive Co-ordination

As already mentioned in section I, the specific information for fuzzy and integral controllers (fuzzy rulebases etc.), which represent the co-ordinating measures in the case of overloadings and faults, is only valid for the network topology for which they have been generated. Since the topology of the system changes in the daily operation of the power system by switching operations, the fuzzy rule bases and additional information for the integral controllers must be followed up automatically to these modifications. This is shown in fig. 7 and designated as “intended topological changes”. In addition, the occurrence of critical events, to which the autonomous system has reacted correctly by means of fuzzy adaptation or setpoint adjusting, may itself lead to a changed topology, for instance through the unintentional failure of a transmission line.

For both cases of topology changes the procedures being performed on the substation and the network control level as shown in fig. 6 have to be activated automatically, so that new specific information is generated for the autonomous agents on

the bay control level. This is called “preventive co-ordination”. The term “normal operational status” means that at the moment no certain co-ordinating action of the autonomous system is required so that only the operating point controllers are in operation.

#### VI. Simulation examples

In the following, two simulation examples are shown in order to illustrate the performance of the multiagent control system. For the investigations the example network according to fig. 4 has been analyzed by means of dynamic simulations. The fuzzy rule bases and global information for integral controllers were generated with the described multiagent system. A failure of a transmission line and the scenario of a line overloading caused by a rapid increase of a load is simulated with a simulation environment in MATLAB®/SIMULINK®. In this way the effectiveness of the co-ordinating measures through generic rules 1 and 2 is shown. The per-unit quantities are:  $S_b = 1250$  MVA and  $U_b = 400$  kV.

##### Failure of a Transmission Line

A failure of line  $L_{17-18}$  is assumed. It occurs at  $t = 0.1$  s with a duration of 4.9 s. Line  $L_{17-18}$  has before been correctly identified as a part of a parallel path of UPFC  $U_1$  by the topology analysis. As the control path of UPFC  $U_1$  has only got one parallel path, this means that there is no parallel path existing after the failure of this transmission line. Without multiagent control the controllers try to keep the setpoint value for active and reactive power flow over  $U_1$  and produce a large value for  $V_l$  up to its limit of 0.15 pu (see fig. 8). However, the setpoint values cannot be kept because of the missing parallel path. This large value of  $V_l$  produces strong power oscillations during the failure of the line. They can be seen in fig. 9. When the multiagent control system is in use, fuzzy module 1 for the generic rule 2 in UPFC  $U_1$  reacts immediately by deactivating the power flow controllers. The effect is visible in fig. 8 with the output of the fuzzy module and the resulting outputs of the power flow controllers. The two power flow PI-controllers of UPFC  $U_1$  only cause a small increase of the manipulated variables during the failure. Consequently, the oscillations in the system occur more weakly during the failure than without the application of the multiagent control system.

It has to be mentioned that there is no FACTS-damping controller active in the power system. The shown effect results only from the slowing down of the controllers.

##### Increase of the Load

After an increase of the system loads the primary controllers of the power plants operate in order to cover the supplementary power requirement. Independent of this the three UPFC fix the power flows on the control paths constant with their fast power flow controllers. Consequently, they can for this moment not be used for the transmission of primary control power.

The capacity of line  $L_{11-19}$  is used to approximately 94 % before the load increase. With a sloping increase of the loads of 14 % at  $t = 1$  s, the primary control power generated by  $G_4$  has to be

transmitted e.g. over line  $L_{11-19}$ , since UPFC  $U_2$  first keeps the unchanged setpoint values. Without the multiagent control system a non-permissible overloading of  $L_{11-19}$  occurs (see fig. 10). If this condition continued, a tripping of the transmission line would be inevitable. In the topology analysis, which has been executed before by the activated multiagent control system, this line is recognized as an element of a parallel path to UPFC  $U_2$ , so that its integral-action controller counteracts directly on the line overloading and increases the setpoint value for the active power flow (fig. 10, below). That causes a shift of the power flow and a relief of  $L_{11-19}$ , so that its maximum loading limit of 0.62 pu (active power) can be kept (fig. 10, above). At  $t = 15$  s the loads are decreased to their original values. This has been simulated to show that the autonomous control system is able to reset itself when its co-ordinating control actions are not needed any more.

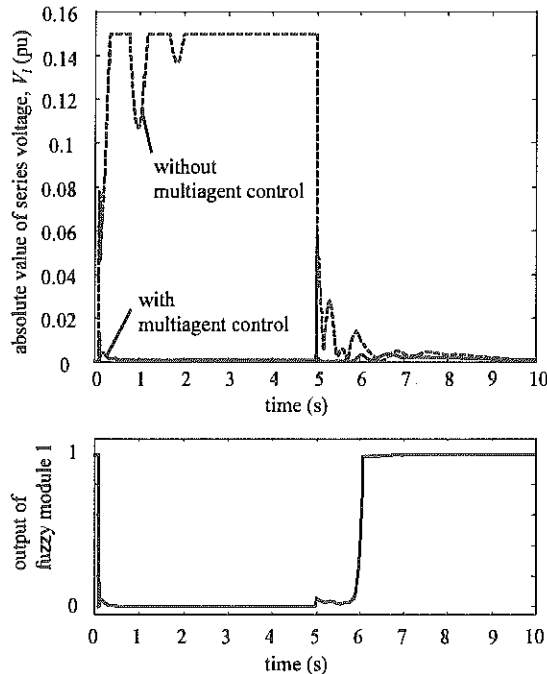


Fig. 8: Series voltage of UPFC  $U_1$  (above) and output of fuzzy module 1 of UPFC  $U_1$

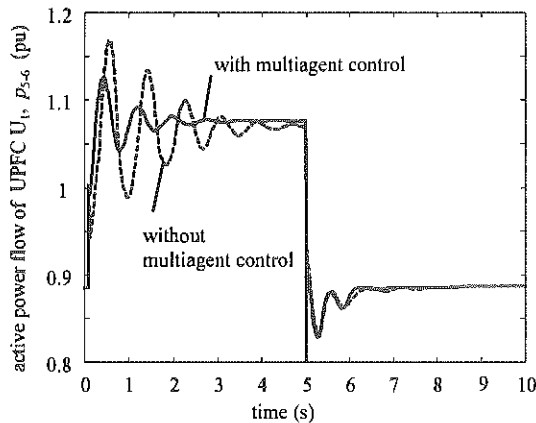


Fig. 9: Active power flow of UPFC  $U_1$

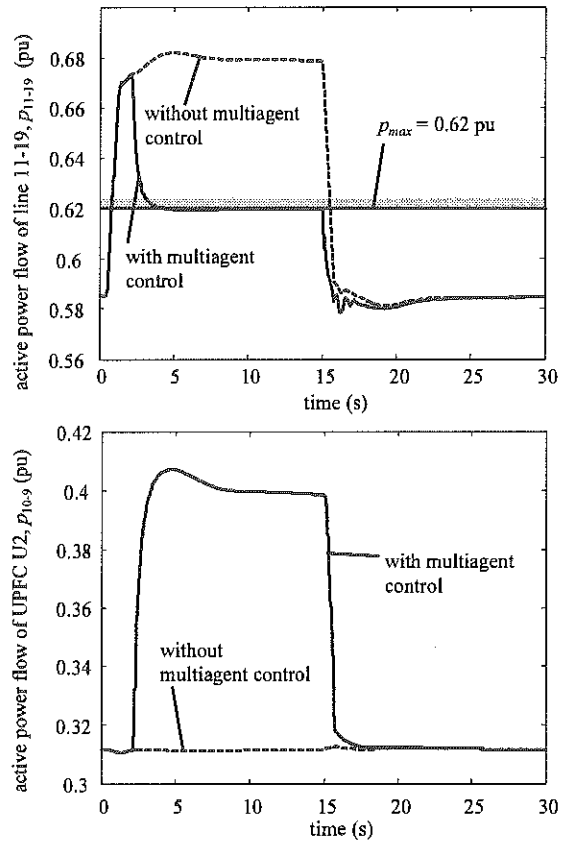


Fig. 10: Active power flow of line 11-19 (above) and active power flow of UPFC  $U_2$  (below)

## VII. Conclusions

The use of FACTS devices offers a flexible management of network-operation from a technical and economical point of view. Beyond this they cause many negative effects which occur due to their short response time after critical events. Hence their advantages can only be used if automatic, quick, intelligent, and preventive co-ordinating measures are performed to eliminate those negative effects. The theory of multiagent autonomous systems offers a structural approach for a co-ordinating control system for FACTS devices. The co-ordinating measures which have to be realized by a multiagent control system can be formulated as generic rules. A multiagent control system has been developed and implemented for such a co-ordination so that the steady-state and dynamical system security is guaranteed after critical events. The control system specifies the generic rules within several steps so that concrete information is made available for decentralized autonomous agents. This information consists e.g. of fuzzy rule bases and is generated preventively in order to guarantee a reaction of the system which is as fast as possible. Simulation results have shown the improvements of the dynamical behaviour and the

secure steady-state operation conditions which are provided by the developed multiagent control system.

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### Biographies

**Christian Becker** was born in Germany in 1972. He received his diploma in electrical engineering in 1996 and his Ph.D. in 2001 from the University of Dortmund, Germany. Currently he is as a senior engineer with the ZEDO - Centre of Consulting Systems, Dortmund. His research activities include modelling, simulation, stability and autonomous control of power systems and FACTS.

**Edmund Handschin** received his diploma in electrical engineering in 1965 from the Swiss Federal Institute of Technology, Zurich, Switzerland, and his Ph.D. in 1968 from the Imperial College London, United Kingdom. From 1969 until 1974 he was a staff member of the Brown Boveri Research Center in Baden, Switzerland. Since 1974 he has been Professor and head of the Institute of Electrical Energy Supply at the University of Dortmund, Germany.

## Discussions on Session II: PROTECTION Part 2

**L. Tsoukalas** (Purdue University): I have a question for Dr. Becker. When you refer to the automatic generation of fuzzy rules, is it automatic or you have to make some decisions about the number of the variables, values and the shapes of membership functions? Or is this somehow generically done for all cases and you won't have to make adjustment yourself?

**C. Becker**: Ok, you're right. Of course membership functions and so on have to be decided at one time. The changes are of course due to the daily change of topology and the number of lines, and of course the lines that have to be monitored. So you've got a generally valid set of fuzzy rules which only have to be doubled or multiplied with the number of lines which you observe. So, for example, you got 4 fuzzy rules which say if there is an overloading, then the output must be high and so on.

**I. Dobson** (University of Wisconsin): I have a general question directed toward this session and previous session. It's about the effects if we have widespread progress along the general lines suggested by all the speakers. Suppose in the future we're very successful with sophisticated control and protection for the more likely failures and the failures we can analyze, then we can run the system up near the limit, and that certainly is beneficial. On the other hand, there is a downside to this as well, you have a much more stressed system, and you have a much more complicated system with many more interactions of a wider area in the system. I think intuitively you would get rare failures and failures can combine in cascade in many unexpected and catastrophic ways. So we have some very good effects from this progress, but also some potentially bad ones. So I like to raise a question - is it obvious in the future that we will come out ahead in this process?

**P.-A. Lof**: I think there is a cost benefit issue. Power utilities today are pretty hard squeezed so the options are limited. I think the provider will benefit at least in the short term. We also said system protection scheme can be used for temporary installations and in particular in use when you have a delay in transmission capacity build-up. So hopefully we provide a better solution than otherwise wouldn't be there. But I realize we are getting more complex systems supervising the grid. It's a large portion of engineering process to develop and put them in there as well as to maintain them. So we might have a more complex situation, but I hardly see the option of putting more transmission lines instead.

**I. Hiskens** (University of Illinois): One general

comment related to Ian Dobson's comments. If I look at the software industry as such, the software system becomes extremely complicated. I was looking at Window 2000. It's a very complicated system. I think anyone ever used Microsoft products will realize that they work really very well when they work, but they do fail frequently. I think that maybe the way the power system could be as well, that we end up with a very complex system that works very well, but then when it fails you are not going anywhere for a while. That's one analogy I guess we could look at in terms of complex systems. On that line, there's a lot of work being done like computer scientists in terms of program verification and tools for verifying the behavior of complex coded systems. The first talk of this session reminded me of some of that verification work. I wonder whether we should be looking at new type of tools in the power systems, where rather than kind of the protection people having in their tool for analyzing protection systems, the power systems people having their tools for analyzing power system dynamics and so forth. Maybe there is going to be need for a more tightly integrated set of tools that really do look at verification of the full system.

**P.-A. Lof**: I must say that sounds like a very valuable comment. I think that we are heading to something more complex and we need definitely verification tools. I also would have underlined that, to implement the system protection scheme, you need collaboration between power system analysts and protection engineers. These two fields, in my personal feeling, are merging, but how far in the future I don't know.

**C. Rehtanz** (ABB): I wanted to make a direct comment on Ian's question. What C. Becker has presented results from the original idea we had three years before. The last conference in Santorini where I presented this original approach using the multi-agent autonomous system. This idea can be an answer to this complexity question. The idea is that something works locally, and probably they get additional information from the top level. If this additional information is not coming, then they fall back to the basic operation. If we proposed some future things like wide area protection, then probably we connect these systems, but we have to always keep in mind that protection must work autonomously. Therefore, we also have this idea of autonomous agents working independently and always knowing what to do if other things are failing. That is also related to A. Phadke's idea. Hidden failure protection is to know what to do if something is occurring. The second comment that there is a huge industrial IT-initiative to try to approach this problem to

make software on the platform that can be used on the lowest level, then components to be integrated in the next level. In other words, it is intended to be a common software approach based on components that are reusable, and therefore not coming from different sides to solve the problems.

**C. Canizares:** My questions are directed toward Dr. Becker. One is more for information, what I'm curious about is the modeling of UPFC in your simulations. The second one is more about the dependency of the agent techniques, the techniques you're presenting on the actual control structure. For example, you assume the decoupled control, that's fine under certain assumptions but some propose coupled PQ controllers. How would that be when you can not decouple some of these variables?

**C. Becker:** The modeling of FACTS devices is the first question. They are very simply modeled, we did not model each thyristor or voltage source converter. More details are in the paper. The second part, of course we're using decoupled control. There can be interactions between those controllers, and maybe influencing the dynamic performance of the whole system. For this we have put controllers for stability impact, which I have not presented here in this paper. This would be another topic. With this controllers we're making coordinating control, we observed the whole system and try to improve the stability or guarantee the stability. This is based on dynamic security of the whole system with this stability controller, perhaps including a power system stabilizer and other controllers.

**C. Canizares:** My question was whether it is dependent on the particular structure of the controller. Do you need them to be decoupled or not? Is it like you turn one off and the other one is on? Is it dependent on that, or we don't need to be dependent? The example you presented assumes independence.

**C. Becker:** I think it is independent. This is what we have observed. It is robust enough. This does not influence the dynamic performance of the system.

**N. Yorino:** I would like to ask Dr. Becker about the robust controller. Also, I would like to add some comments on the autonomous or multi-agent system. I think autonomous control sometimes requires a communication within the system, so in that case, if the communication is lost, what happens? A dangerous situation is possible. Also, the multi-agent system usually uses some heuristic techniques, I think. In that case, it is quite difficult to realize the optimality as well as robustness. The robustness can only be checked by the simulation base, not the theoretical base.

**C. Becker:** So the structure of the autonomous control system is that agents only have to get local information.

You see the agents on the bay-control level. They can act with only local information, for example, about the power flow of the device, and they act independently with this local information. They may need global or specific information from a higher level for realizing the preventive control. This is not time critical. If, for example, some information channel is lost, then you of course have enough time to generate specific information from a higher level, because it is only critical in case of critical events. Of course it is necessary that you have the decentralized and local information; if not, you have a problem. What we intended to do is to program or implement an emergency part for each agent to determine what to do if some information channels are lost.

**Chairman (H. Sasaki):** I would like to ask a question about the economics. After being asked to review a lot of papers that deal with FACTS devices to increase power transfer, I wonder if UPFC is really economically justifiable for a small system.

**C. Becker:** Of course you're right. This is generally an expensive device. There is one UPFC in operation the US and it has been expensive. But I have chosen the unified power flow controller because it combines all other features of other FACTS devices. Generic rules and coordination measures are still developing, if you take a more simplified device. For example, static synchronous series compensators that perform control of the reactor and the reactor power flow. If you've got only voltage controlling devices, then specific generic rules are valid and others are not. We have chosen the UPFC in order to cover the whole field.

**L. Tsoukalas:** This discussion reminds me very much of similar discussions in the nuclear industry, the chemical industry and aerospace industry. There seems to be a kind of paradoxical attitude. There is a group of tech-community that treats intelligent systems with great enthusiasm and sometimes like Pandora's box. This is typically after learning something about intelligent systems. There is another part of the community that very much resists, dismisses and rejects the promises of intelligent systems. So to begin with, it seems like we are trying to address something that is complex and complicated by putting another layer of complexity on top of it. There are all kind of issues about verifications, validation, reliability and so on. There are quite a few methodologies and technologies for doing V and V in very critical systems like power plants and airplanes. On the other hand, if only we get down to it, the magic of autonomy, the magic of intelligence, there is a lot we don't know about these things. When it comes to translating this to technologies, it only works in a very well defined context, in very well defined domains. That doesn't mean that there is no universal appeal. We all want to solve problems but we need tremendous caution. There is a lot that agents can do for improving the



control system and for decision making. There are a lot they can't do, they may end up being one great complex system to take care, and in reality will not really work in the field condition. There is a lot we go through, for example, in terms of generating knowledge and mining databases. That is very much limited by inability of the machine system to find rules. Nonetheless, there are great promises and great challenges. I guess part of the research adventure is to identify for this specific technology, which things work, which don't work to advance the frontier of knowledge. But generally, I'll be somewhat sympathetic to the comments that Ian made, and we need to approach these things with great caution.

**P.-A. Lof:** We know that large power utilities like EDF and Hydro Quebec already have developed system protection schemes. I think it is very important right now to get things right from the beginning. I would like to ask you to comment on the event bases. The event-based protection scheme is for preprogrammed quick events. So a limited number of events can be handled, and they are easy to identify. But the response-base is tricky, because they are more general, but also slower. Because they have to wait for the response from the system, for example, frequency, voltage decay or something before they can take actions. So I think they have to build simple building blocks in the beginning, then we have to be very concerned that we have different designs for different systems, because different utilities have from different perspectives. I think all of these solutions will sooner or later come. We have to develop very systematic engineering principles on how to design them. That is the task for tomorrow.

**Session III:**  
**MARKETS**

Tuesday, August 28, 09:00–12:00

Chair: Peter W. Sauer

## Strategic Equilibria in Centralized Electricity Markets

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### Introduction

Competitive electricity markets in which the participants individually submit their preferred schedules, and subsequently the IGO centrally sets the trading solution based on those schedules, have been put in practice. This market model is usually known as PoolCo and the PJM Interconnection is a specific example of its implementation [1]. The trading solution set by the IGO aims usually at short-term efficiency, which may be measured by the social welfare or surplus [2], and incorporates rules to enforce feasibility. We define as feasible a trading solution that respects both the operational and physical constraints of the electric system. An OPF (Optimal Power Flow) tool, which maximizes the participants' welfare - based on their bids and offers - subject to system constraints, seeks both short-term efficiency and feasibility.

Participants in a market are expected to behave rationally, where rationality may be translated into the attempt to maximize individual profit. In the PoolCo model, players may do that by untruthfully revealing their cost/benefit in their offer/bid curves [3].

Given specific market rules, it is of great interest to be able to model the strategic behavior (or gaming) of the market participants and to identify solutions of those games, which we modeled as static non-cooperative continuous-kernel games under complete information [4],[5]. Non-cooperative means that each individual player is pursuing his or her own interests, and continuous-kernel stands for the fact that each player has at his or her disposal a continuum of choices and also that the utility functions are continuous. The game is static due to the fact that the process of decision-making is simultaneous for all players involved. It is implicit that the game is not repeated. Complete information means that every player knows his or her own costs/benefits - and those of all the other players in the market - and that constitutes common knowledge. This is believed to be true for producers operating in electricity markets, for which a good estimate of costs may be obtained from the daily spot price of fuels (natural gas or other) and from the technological capacity and corresponding heat rates of the power plants [6]. Consumers, on the other hand, have a weak responsiveness to price changes due, in great extent, to technological restrictions. This fact may be translated into limited ability to game the market. We will, therefore, focus primarily on the supply-side gaming.

The solutions prescribed by the proposed game are the so-

called Nash equilibria, either in pure or in mixed strategies. They constitute the strategically stable or self-enforcing points in the bidding space from which the players have no incentive to deviate. Stability may be alternatively defined with respect to the readjustment scheme employed by the players when searching for the equilibrium points.

The paper addresses the problem of how to find multiple equilibria in PoolCo model where the line constraints have been considered. It makes use of a modified version of a previously proposed readjustment scheme (or algorithm) for a single equilibrium problem and shows a systematic approach for solving the multiple equilibria problem[7][8].

Modeling strategic behavior in electricity markets is of special importance if opportunities for market power abuse based on gaming by participants are to be identified. The present situation in the Californian market enforces the feeling that carefully designed market rules cannot be overrated. Furthermore, the goals of a competitive market may be improved by acknowledging the players' opportunities to game, by correctly identifying them, and consequently either preventing those opportunities or controlling their consequences. Therefore, this work is not specially aimed at providing players with tools to pursue their objectives, but, in contrary, to clarify in which context gaming opportunities may take place.

The paper has four more sections and one appendix. In section two we revisit the algorithm that identifies a Nash equilibrium in a PoolCo model. Section three illustrates the possibility of existence of multiple of those equilibria and describes the proposed procedure to systematically find them. The method is exemplified in section four through a simple test system. In section five we draw some conclusions about the proposed method. In the appendix we give the data and the results for the example presented in section four.

### The Individual Welfare Maximization

The original Individual Welfare Maximization (IWM) algorithm assumes that the IGO runs a centralized economic dispatch subject to the system constraints (OPF) [7][8]. This OPF, which uses bids and offers freely submitted by the participants, sets the nodal prices (Lagrangian multipliers) that are used to charge/pay consumption/generation on every node of the grid [9]. The participants game by untruthfully revealing their costs/benefits on their offer/bid curves or schedules and they may do so by continuously changing one or more parameters of the marginal cost/benefit curves that they submit to the IGO. Which parameter or parame-

ters they change is not relevant. What is important is the state or operational equilibrium that is attained by changing those parameters. We assume that the players have reasonable estimates about all participant's true costs/benefits and we also assume that these estimates constitute common knowledge among players; moreover, that the players are rational also constitutes common knowledge. The schedules submitted by the players are valid for one time period of the market, typically one hour. Therefore, they need to optimize their bid/offer for a specific time period, which is viewed as a snapshot in time.

Each player in the market may find the equilibrium points through his or her own choice of the parameters of the reported schedule and by mimicking the other players' choices. This is possible from the rationality and the complete information assumptions. Hence, the equilibria found by each player alone will match those found by the other players. This constitutes the main strength of the Nash equilibrium concept.

The individual welfare maximization problem is cast as a nested optimization problem. The inner problem is the OPF, and the outer problem is the optimization of the individuals' utility functions subject to the OPF solutions. We denote by  $f_p()$  the utility function of player  $p$ . The vectors of generation and load controlled by player  $p$  are denoted by  $\mathbf{P}_p$  and  $\mathbf{D}_p$ , respectively. Each player  $p$  controls a vector of reported variables that is represented by  $\alpha_p$ . The nodal prices applied to the generation and load controlled by player  $p$  are a byproduct of the OPF and appear as  $\lambda_p$ . The cost and benefit functions of each generator and load are denoted by  $C_i$  and  $B_i$ , respectively.  $\mathcal{G}$  represents the set of generators and  $\mathcal{D}$  represents the set of loads. The cost and benefit function are assumed to be well described by quadratic functions.

$$C_i(P_i) = a_{P,i} P_i^2 + b_{P,i} P_i + c_{P,i}, \quad i \in \mathcal{G} \quad (1)$$

and

$$B_i(D_i) = a_{D,i} D_i^2 + b_{D,i} D_i + c_{D,i}, \quad i \in \mathcal{D} \quad (2)$$

In this context,  $\alpha$  may, for example, replace the true cost/benefit variable  $a$  in the reported marginal curve. The equality and inequality constraints are represented by  $\mathbf{g}()$  and  $\mathbf{h}()$ , respectively, where  $\mathbf{P}$  is the vector of all generated power,  $\mathbf{D}$  is the vector of all loads, and  $\mathbf{x}$  represents the vector of state variables. The individual welfare maximization problem may be thus described as follows.

$$\begin{aligned} & \max_{\alpha_p} f_p(\mathbf{P}_p, \mathbf{D}_p, \lambda_p) \\ & \text{s.t. } (\mathbf{P}_p, \mathbf{D}_p, \lambda_p) \text{ are determined by} \\ & \left( \begin{array}{l} \max_{\mathbf{x}, \mathbf{P}, \mathbf{D}} \sum_{i \in \mathcal{D}} B_i(D_i, \alpha_{D,i}) - \sum_{i \in \mathcal{G}} C_i(P_i, \alpha_{P,i}) \\ \text{s.t. } \mathbf{h}(\mathbf{x}, \mathbf{P}, \mathbf{D}) = \mathbf{0} \\ \mathbf{g}(\mathbf{x}, \mathbf{P}, \mathbf{D}) \leq \mathbf{0} \end{array} \right) \quad (3) \end{aligned}$$

The utility function of each player  $p$  is given by the difference between the sum of benefits minus charges and the sum of payments minus costs that results from the set of his or her controlled generators and loads. We write it below, where the fixed components have been dropped.

$$\begin{aligned} f_p(\mathbf{P}_p, \mathbf{D}_p, \lambda_p) &= \sum_{i \in \mathcal{D}_p} [B_i(D_i, a_{D,i}, b_{D,i}) - \lambda_i D_i] + \\ & \sum_{i \in \mathcal{G}_p} [\lambda_i P_i - C_i(P_i, a_{P,i}, b_{P,i})] \\ &= \mathbf{D}_p^T \mathbf{A}_{D,p} \mathbf{D}_p + \mathbf{B}_{D,p}^T \mathbf{D}_p - \\ & \lambda_{D,p}^T \mathbf{D}_p + \lambda_{P,p}^T \mathbf{P}_p - \\ & \mathbf{P}_p^T \mathbf{A}_{P,p} \mathbf{P}_p + \mathbf{B}_{P,p}^T \mathbf{P}_p \end{aligned} \quad (4)$$

The quadratic parameters are represented in the diagonal elements of matrices  $\mathbf{A}_{D,p}$  and  $\mathbf{A}_{P,p}$ . The linear parameters appear in  $\mathbf{B}_{D,p}$  and  $\mathbf{B}_{P,p}$ .  $\mathcal{G}_p$  and  $\mathcal{D}_p$  are the set of generators and the set of loads, respectively, controlled by player  $p$ .

In order to determine the best set of bid/offer parameters, the players – whose set is denoted by  $\mathcal{P}$  – readjust  $\alpha_p$  on each iteration  $k$  by using Newton's method, until a stationary point is reached.

$$\alpha_p^{(k+1)} = \alpha_p^{(k)} - (\nabla_{\alpha_p}^2 f_p)^{-1} \big|_k \cdot \nabla_{\alpha_p} f_p \big|_k, \quad \forall p \in \mathcal{P} \quad (5)$$

If a stationary point is found, then it is stable with respect to the selected readjustment scheme and it constitutes, by definition, a Nash equilibrium.

The readjustment schemes presented so far in the literature propose that it be done for each unit (generator or load) of each player at a time [7],[3]. Although this made sense in a discontinuous kernel – for it avoids cycling when near the solution – it is not necessary for the IWM readjustment scheme. So, the change proposed to the original IWM is to let all the players change all their bids/offers' reported parameters on a single iteration. So, instead of optimizing the parameters for each unit of each player at a time before proceeding to the next one, a complete Newton-step is performed on each individual utility function – in order to optimize all his or her reported parameters – for each readjustment step. This change accelerates the algorithm because the readjustment evolves using all the dimensions of the bidding space, instead of using only one variable controlled by a single player. The Gradient and the Hessian of the individual utility functions may be obtained from the Newton-based OPF solutions, and the proposed change implies using the cross derivatives of each individual utility function with respect to the control variables of the corresponding player.

Another part of the original algorithm that is neglected in this work is the step-size selection – originally used to prevent crossing regions of the bidding space where the utility

functions are not differentiable due to the system constraints [7]. As we will see in the next section, this problem is circumvented by enforcing some of the system constraints and relaxing others, ensuring, in this way, differentiable utility functions in every specified region of the bidding space.

### Searching for Multiple Equilibria

In the search for multiple equilibria we consider the problem in which only the generators game. We do this because this is the problem faced by present-day electricity markets. One should, however, consider the following characteristic of equilibria: if both generators and loads game, and two of them happen to be in the same bus, this may give origin to a continuum of equilibria. This is so because the load and the generator would work as substitutes with respect to each other.

#### *The proposed search method*

If the cost functions of the generators are convex and the constraints are linear, the problem is well behaved inside each region defined by the linear constraints. This implies the use of D.C. power flow equations, which, of course, implies some simplification. For example, the California ISO uses a D.C. model to allocate transmission during market re-dispatch [10]. The differentiability of the utility functions breaks down only when linear constraints – for example, line constraints – are hit. Therefore, if we are able to start the IWM algorithm with an initial solution inside each region defined by the constraints, then the convex functions and the linear constraints guarantee convergence if a solution exists in the region [5]. In case the algorithm crosses the boundaries of the region, it means that there is no equilibrium in the specified region. However, initializing the algorithm inside a specific region is not easy. Instead, we run the IWM considering the linear constraints defining each region as equality constraints and we relax the remaining inequalities so they are never hit.

In Figs. 6-9 we show the contour of the utility function – resulting from the OPF solution – of player 1 in the 4-bus test system used in example of section 4, as he or she changes the parameters of the two generators under his or her control. In Figs. 6 and 7 the limit on line 1-3 is modeled as an inequality constraint, whereas in Figs. 8 and 9 this limit is changed to an equality constraint. Fig. 6 of the appendix shows two equilibrium points: one when the line constraint is binding (or active) and another one when this constraint is not binding (or inactive). The observation of the figures indicates that, if one equilibrium exists for the original problem with the constraint active, then it will also exist for the modified problem wherein the line is forced to operate exactly at that limit (Figs. 6 and 7) and the remaining line limits are relaxed. Yet, that equilibrium will only appear in the modified problem if it does not exist in the original problem (Figs. 8 and 9). This gives rise to the necessity of checking the solutions of the modified problem back in the original problem.

In summary, we proceed in the following way: the IWM is run for each region of the bidding space by forcing the correspondent lines to operate at their limits and relaxing the remaining ones; if an equilibrium is found, then the IWM is run for the original problem, using the possible equilibrium as starting point, for the purpose of checking its existence. The biggest drawback resulting from this procedure is, of course, the necessity of checking all the possible feasible regions given by the feasible combinations of constraints. As a result of that, the problem is of combinatorial nature and the number of possibilities may render a non-manageable problem. In the next subsections we give some insights on how to overcome this difficulty.

#### *Feasible cases*

A feasible case is one that is supported by a power flow solution. Since we assume D.C. flows on lines, the feasible solutions may be easily checked by running a LP (linear programming) problem.

The algorithm to find multiple equilibria must, therefore, be run only for the feasible cases (or regions) in the bidding space. The unfeasible regions are never reached and we need not to consider them. So, prior to initiating the search, we build a database of feasible cases corresponding to the feasible combinations of binding constraints. In case we take into consideration only the line constraints, we have a database comprising the cases associated with feasible regions of the bidding space, and this database may be represented as  $\mathcal{C}_i = \{c_1, c_2, \dots, c_m\}$ , where  $c_i = \{0, 1, -1\}$ , and  $m$  is the number of lines in the system. The triplet  $c_i$  allows us to represent each line to be either uncongested, or congested in each of the two possible directions.

#### *Problem size reduction*

Due to the non-polynomial nature of the problem –  $\mathcal{O}(3^m)$ , if only the line constraints are taken into account – it is impossible to manage any real life examples in the absence of any form of reducing its size. Fortunately, the LP program, together with careful propagation and pruning, allows the elimination of a substantial number of cases. In the tree of Fig. 1 it is shown the sequence in which the cases must be generated in order to allow pruning. Every new child case is generated from the parent case by including more congested lines that are represented further to the right, until the last represented line is reached. This simple procedure avoids repetition of cases. Then, for each new level of the tree, all cases are tested, but only the feasible ones are propagated to the next level. The unfeasible ones are pruned (eliminated and not propagated) and the cases that are feasible for a configuration further down in the tree are eliminated but still propagated. For real system where the players have the ability to congest a reduced number of lines, this method may prove very efficient.

Secondly, in real systems, the operators know from their experience which ones are the lines that, under certain operating conditions, are likely to be congested. In the California

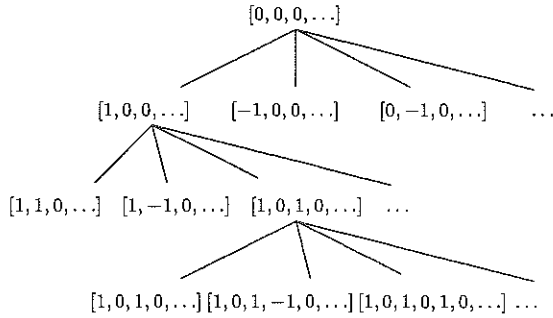


Fig. 1. Generation of cases

ISO, for example, this knowledge is used by the system operators to define the inter-zonal interfaces [10]. The market participants may now use this same knowledge in order to avoid running an incommensurable number of cases. In addition, once the history of congested lines has been established no other cases beyond the ones inferred from that history need to be investigated.

#### Mixed-strategy equilibria

The method, as it was proposed, is suitable for finding equilibria in pure strategies. For mixed strategies, the algorithm needs to be modified and that is object of current research. First, the algorithm must be allowed the crossing of regions in the strategy space. It is the discontinuities caused by the system constraints that might cause the reaction curves of players not to cross and, therefore, give origin to the equilibria in mixed strategies [7]. Secondly, this would require the algorithm to be initialized precisely in the specified regions, without relaxing any of the remaining constraints.

The equilibria in mixed strategies may be identified because they make the proposed algorithm cycle back and forth across a given constraint (or constraints). The solution for a mixed-strategy equilibrium is the one that maximizes the expected profit of all players, for strategies with assigned probabilities, in the spanned regions. The expected profit,  $e_p$ , for player  $p$  may be written as in (6), where  $f_p^r(\cdot)$  denotes the profit of player  $p$  in region  $r$  and  $S$  denotes the set of regions spanned by the equilibrium. The probability with which a given strategy  $\alpha_p^r$  is played is denoted by  $y_p^r$ . The maximum number of players is denoted by  $P$ .

$$\begin{cases} e_p = \sum_{r \in S} \left[ f_p^r(\alpha_1^r, \dots, \alpha_p^r, \dots, \alpha_P^r) \cdot \prod_{p \in P} y_p^r \right] \\ \sum_{r \in S} y_p^r = 1, \quad \forall p \in P \end{cases} \quad (6)$$

#### Example

We ran the proposed method on the 4-bus test system whose configuration can be seen in Figs. 2-5 of the appendix. Table I contains the line reactances. The producers and consumers

participating in this small market are assumed to be well characterized by their cost and benefit curves as in (1) and (2), whose parameters' values are showed in Table II and Table III. Table IV describes the ownership of the generators.

Because the test system has 4 lines, we could expect a maximum of 81 feasible regions. In fact, there exists a power flow solution for only 27 of those regions and, hence, a database of only those cases is built prior to initiating the search.

In this experiment only the generators game and, if both of the players run the search algorithm, then they will find the equilibrium solutions of Table V. Upon confirmation, only equilibria 1-4 survive, and those are illustrated in Figs. 2-5 of the appendix. There we can observe which lines are congested for each equilibrium operating point. Equilibrium 5 does not survive confirmation and, if we allowed the confirmation algorithm to proceed, it would end up being attracted to a cycle that is nothing else than a mixed-strategy equilibrium that spans regions  $\{0, 1, 0, 0\}$  and  $\{0, 0, 1, 0\}$ .

In Table VI we show the profits attained by the players in the different pure-strategy equilibria that were found using the search algorithm. It is easy to verify that the first three equilibria provide lower revenues for both the players than the revenues obtained in the fourth equilibrium. In other words, the first three equilibria are strictly dominated by the fourth equilibrium and could be thus eliminated. This is not always the case – and might not be the case were we in possession of the solutions in mixed strategies – and the players may be left in the end with more than one equilibrium point that is not eliminated by any dominating strategy to choose from.

In Figs. 6-9 of the appendix we illustrate how the utility function of player 1 may change when the limit on line 1-3 is varied. It is possible to observe that one of the equilibrium points vanishes when the limit on the line is sufficiently high (Fig. 8). This fact is not apparent in the modified problem wherein the limit is enforced as an equality (Fig. 9). In the making of Figs. 6-9, the price schedule parameters of generators 2 and 4 controlled by player 2 were fixed to  $\hat{a}_2 = 0.089$  and  $\hat{a}_4 = 0.181$ , respectively.

#### Conclusions

The work presented in this paper addresses the problem of multiple strategic equilibria that constitute the natural operating solutions in the bidding space for players participating in centralized electricity markets. Moreover, the paper shows that under specified assumptions it is possible to employ a systematic procedure to find those multiple equilibria.

When the players are unaware of the set of lines that can be congested by gaming, they must be able to tell the feasible cases from the non-feasible ones. We showed a simple method, based on careful propagation and pruning, that helps building a meaningful database.

In the absence of any straightforward rule to eliminate equilibrium solutions, as elimination of dominated strategies, the players are left with a multitude of answers for the gaming problem. Future research on the paper's topic will have necessarily to address this problem.

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## Biographies

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## Appendix

TABLE I  
TEST SYSTEM LINE PARAMETERS.

| Line | Reactance<br>(p.u.) | Maximum flow<br>(p.u.) |
|------|---------------------|------------------------|
| 1-2  | 0.790               | 1.87                   |
| 1-3  | 0.116               | 1.81                   |
| 2-4  | 0.122               | 2.11                   |
| 3-4  | 1.030               | 1.93                   |

Base MVA = 100, Base kV = 345

TABLE II  
PRICE SCHEDULES' PARAMETERS

| Generator | Parameters                      |                   |
|-----------|---------------------------------|-------------------|
|           | $a_P$<br>(\$/MW <sup>2</sup> h) | $b_P$<br>(\$/MWh) |
| 1         | 0.05                            | 15.0              |
| 2         | 0.05                            | 6.0               |
| 3         | 0.10                            | 1.0               |
| 4         | 0.10                            | 1.0               |

TABLE III  
VALUE SCHEDULES' PARAMETERS

| Load | Parameters                      |                   |
|------|---------------------------------|-------------------|
|      | $a_D$<br>(\$/MW <sup>2</sup> h) | $b_D$<br>(\$/MWh) |
| 1    | -0.10                           | 80.0              |
| 2    | -0.10                           | 80.0              |
| 3    | -0.50                           | 440.0             |
| 4    | -0.50                           | 440.0             |

TABLE IV  
GENERATOR'S OWNERSHIP

| Player | Generator |   |   |   |
|--------|-----------|---|---|---|
|        | 1         | 2 | 3 | 4 |
| 1      | ✓         |   | ✓ |   |
| 2      |           | ✓ |   | ✓ |

TABLE V  
REPORTED PARAMETERS FOR EACH EQUILIBRIUM POINT

| Eq. | Parameter                             |                                       |                                       |                                       |
|-----|---------------------------------------|---------------------------------------|---------------------------------------|---------------------------------------|
|     | $\hat{a}_1$<br>(\$/MW <sup>2</sup> h) | $\hat{a}_2$<br>(\$/MW <sup>2</sup> h) | $\hat{a}_3$<br>(\$/MW <sup>2</sup> h) | $\hat{a}_4$<br>(\$/MW <sup>2</sup> h) |
| 1   | 0.0931                                | 0.0883                                | 0.1552                                | 0.1662                                |
| 2   | 0.0787                                | 0.0922                                | 0.1975                                | 0.1783                                |
| 3   | 0.0965                                | 0.0868                                | 0.1638                                | 0.1748                                |
| 4   | 0.0826                                | 0.0906                                | 0.2063                                | 0.1879                                |
| 5   | 0.0000                                | 0.0000                                | 0.2696                                | 0.2697                                |

TABLE VI  
PLAYERS' PROFITS FOR EACH EQUILIBRIUM POINT (\$/h)

| Equilibrium | Player |        |
|-------------|--------|--------|
|             | 1      | 2      |
| 1           | 16,514 | 20,226 |
| 2           | 17,303 | 21,040 |
| 3           | 16,628 | 20,694 |
| 4           | 17,523 | 21,579 |

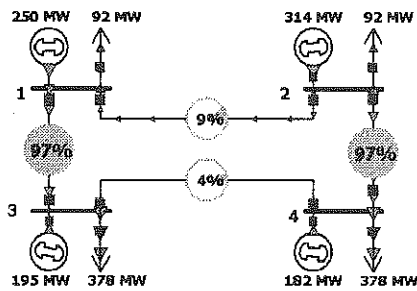


Fig. 2. Equilibrium 1

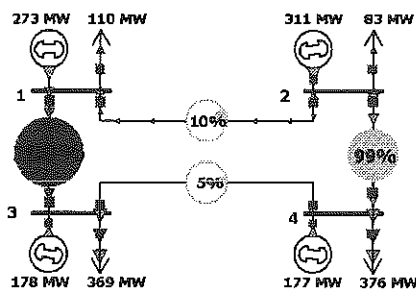


Fig. 3. Equilibrium 2

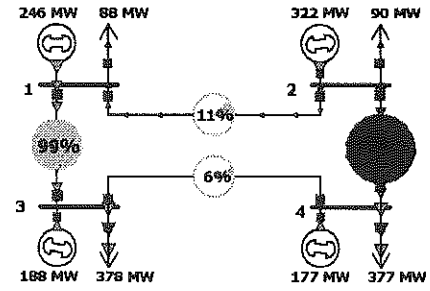


Fig. 4. Equilibrium 3

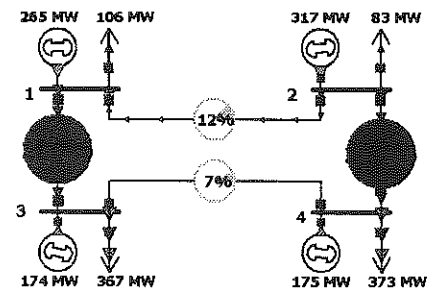


Fig. 5. Equilibrium 4

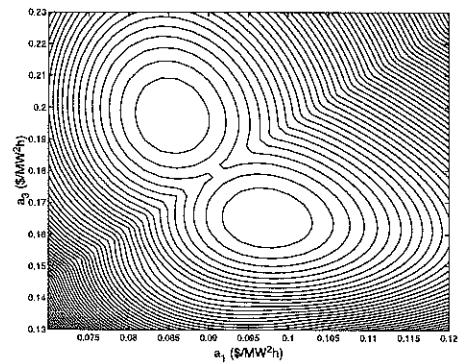


Fig. 6. Player 1 utility function;  $P_{13} \leq 195 MW$

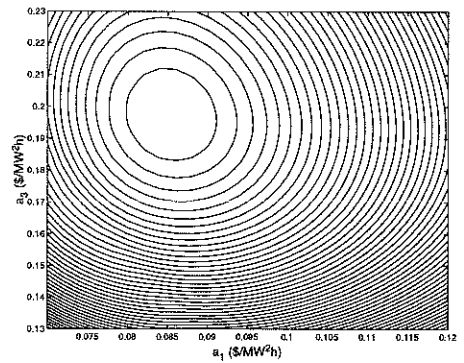


Fig. 7. Player 1 utility function;  $P_{13} = 195 MW$



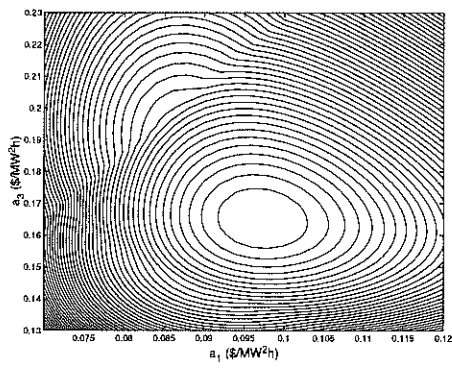


Fig. 8. Player 1 utility function;  $P_{13} \leq 210 \text{ MW}$

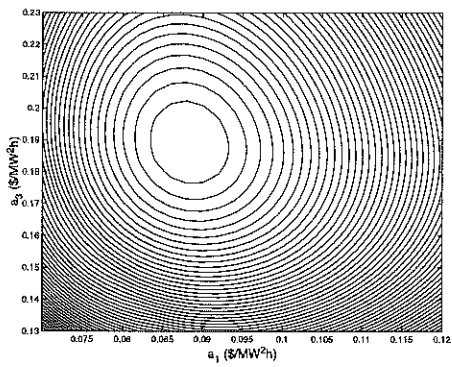


Fig. 9. Player 1 utility function;  $P_{13} = 210 \text{ MW}$

# Design of Ancillary Service Markets: Reactive Power and Frequency Regulation

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## Abstract:

This paper attempts to examine two of the most important activities of the system operator in a deregulated power system – maintaining the system voltage profile within acceptable limits and the system frequency around the nominal. The paper proposes different models for the participants in reactive power and regulation service markets to submit their bid offers. These market models and bidding structures have been incorporated within the system operator's optimization framework to evaluate the most viable ancillary service contracting and procurement scheme.

## 1. Introduction

The function of an electric utility is not limited to power generation, transmission and its distribution to customers. It also has to ensure a required degree of quality and safety, provide corrective measures when faced with incidents, and perform several other functions. To this effect, certain services, such as, scheduling and dispatch, frequency regulation, voltage control, generation reserves, etc. are required by the power system, apart from the basic energy and power delivery services. These services, which are now being referred to as *ancillary services*, had all along been part of the normal electricity supply and not been separated in the traditional vertically integrated power systems.

In a deregulated environment, utilities have no direct control over power stations in their service area. These ancillary services are no longer treated as integral to the electricity supply. They are unbundled and priced separately, and utilities have to purchase ancillary services from ancillary service providers.

In such an environment, issues pertaining to costing of ancillary services, appropriate pricing mechanisms to recover the costs, etc. becomes extremely important for proper functioning of the system for all the market participants.

The Federal Energy Regulatory Commission (FERC) specified ancillary services that are required for routine operations. They are *system control*, *voltage control*,

*regulation*, *load following / energy imbalance*. Ancillary services that are needed to prevent an outage from becoming a catastrophe, are *spinning reserves*, *supplemental reserves* and *network stability services*. Furthermore, *system blackstart capability* is a service needed to restore the system after a blackout.

In this paper, the market mechanism of two ancillary services, reactive power and frequency regulation, are discussed.

## 2. Reactive Power as An Ancillary Service

Reactive power management and payment mechanisms vary for each deregulated electricity market. In the U.K. electricity market, the role of the ISO is handled by National Grid Company plc. (NGC). The Grid Code places a minimum obligation on all generating units, with a power generating capacity more than 50 MW, to provide a basic (mandatory) reactive power service. The service is termed as Obligatory Reactive Power Service (ORPS). The generators with reactive power capability in excess of the Grid Code can offer an *Enhanced Reactive Power Service (ERPS)*. Both ORPS and ERPS providers can offer tenders for capability and utilisation prices to NGC [1]. In New York power pool, the New York ISO (NYISO) is responsible for providing reactive power support service. Generating resources, which operate within their capability limits, are directed by the ISO to produce or absorb reactive power to maintain system voltages within limits. The service is provided at embedded cost and lost opportunity cost [2]. In Australian electricity market the ISO, National Electricity Market Management Company (NEMMCO) recognises only that reactive power provided by synchronous generators and synchronous condensers as ancillary services. The total payment for reactive power service is composed of *availability payment*, *enabling payment* (compensators only) and *compensation component* (generators only) [3].

Reactive power need to be introduced in the ancillary service markets in a fair and equitable manner. Providers for reactive power support should be compensated for their services. However there are several complex issues involved in

handling a reactive power service and in creating an efficient market for reactive power.

- Reactive power services need to be provided locally due to the technical problems associated with its transportation over lines.
- The value of a reactive power service is location dependent.
- Due to the limited number of potential players in this market, there is an opportunity for market power.
- The market will most likely be a monopsony, the ISO being the single buyers.

### 2.1 Synchronous Generators as Ancillary Service Providers

While reactive power ancillary services may be provided by many different parties such as generators, transmission / distribution companies, or even large customers, the importance of synchronous generators in providing the service remains a critical issue. This is due to their presence and importance in the real power market, and which will also determine their role in the reactive power services.

In the Australian market, the provision for reactive power from generators is separated in two categories:

- The mandatory reactive power support, and
- Reactive power as an ancillary service

It is *mandatory* for the generators to provide reactive power within the operating power factors of 0.9 lagging and 0.93 leading. Beyond this mandatory component, is the *ancillary service component*, which is left to the generators to offer [4].

#### 2.1.1 Cost of Reactive Power Production

The power output of a synchronous generator is usually limited to a value within the MVA rating by the capability of its prime mover. When real power and terminal voltage is fixed its armature or field winding heating limits determine the reactive power generation from the generator. The armature heating limit and field limit are shown as Figure 1.

In Figure 1,  $Q_{base}$  is the reactive power required by the plant for its auxiliary requirement. If the operating point lies inside the limiting curve, at  $(P_A, Q_{base})$  then the unit can increase its reactive generation from  $Q_{base}$  up to  $Q_A$  without requiring re-adjustment of  $P_A$ . It will incur increased losses in the windings and hence increase in its costs. This cost can be termed as the *cost of loss component* and is incurred by the synchronous generator with reactive power production (both lagging and leading).

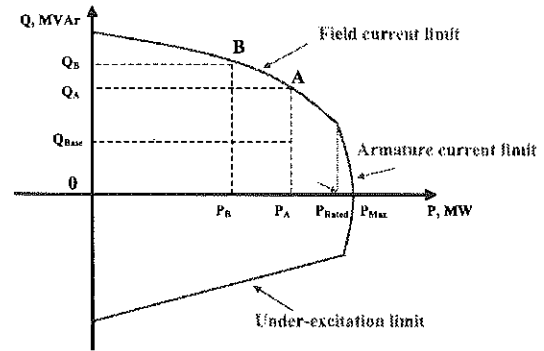


Figure 1. Synchronous Generator Capability Curve

If the generator is operating on the limiting curve, any increase in  $Q$  will require a decrease in  $P$  so as to adhere to the heating limits. Consider the operating point 'A' on the curve defined by  $(P_A, Q_A)$ . If more reactive power is required from the unit, say  $Q_B$ , the operating point requires shifting back along the curve to point B  $(P_B, Q_B)$ , where  $P_B < P_A$ . This signifies that the unit has to reduce its real power generation to adhere to field heating limits when higher reactive generation is demanded. It will hence incur revenue loss (RL), which needs to be compensated net of its cost savings from reduced generation, expressed as follows:

$$RL = \mu(P_A - P_B) - [C(P_A) - C(P_B)] \quad (1)$$

In (1),  $\mu$  is the real power price and  $C(\cdot)$  is the generation cost as a function of real power production. The term RL can also be called the *opportunity cost component* of reactive power generation from the generator.

The above two components are explained in Figure 2. However, it is to be noted that the nature of the plot shown is only figurative to illustrate the two components.

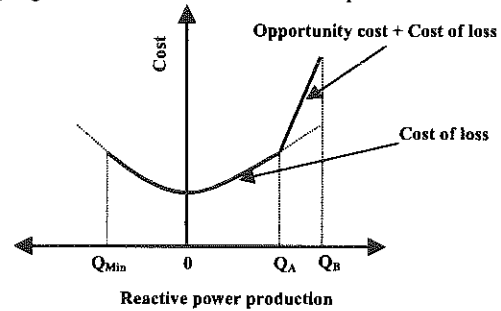


Figure 2. Reactive power production versus increased costs incurred by a synchronous generator

Understandably, the ISO will not be in a position to determine these two components for a generator since information on real power prices may not be known to the

ISO if these are fixed through a bilateral contract, nor the generator's *cost of loss function* will be known. An appropriate option in such a case is to call for *reactive bids* from all generators. A possible structure of such *reactive bids*, which the ISO should call for, from independent generators, is discussed next.

### 2.1.2 Structure of Reactive Power Bids from Generators

In this section we consider the possible reactive bid structure of synchronous generators. We define three operating regions of a synchronous generator on the reactive power co-ordinate. The operating regions on the reactive co-ordinate can be defined as follows (Refer Figure 1):

**Region-I: 0 to  $Q_{base}$ :** Production in this region caters to the reactive power needed by the generator to maintain its own equipment. This includes reactive consumption by unit's auxiliaries. Therefore any reactive power generated in this region does not qualify as an ancillary service. *The generator should not be entitled to receive any payment for reactive power production in Region-I.*

**Region-II: ( $Q_{base}$  to  $Q_A$ ) and (0 to  $Q_{Min}$ ):** This region denotes that amount of reactive power, which the generator can provide or absorb, without having to reschedule its real power generation. However, as mentioned earlier, this will increase the generator's real power losses in the windings. Therefore, the generator will expect to be paid for the cost of losses (probably at the prevailing spot-market rates).

*The generator is entitled to receive 2 components of payments in this region:*

*The Availability Component + The Cost of Loss Component*

**Region-III:  $Q_A$  to  $Q_B$ :** This region denotes that amount of reactive power which a generator is willing to produce, at the cost of having to reduce its own real power generation. The generator stands to lose revenue from the unfulfilled real power selling contracts. The financial compensation that the generator expects from its reactive power service is the opportunity cost of its real power sell, given by (1). *The generator is entitled to receive payment commensurate with its opportunity cost of reduced real power production. The generator's Expectation of Payment Function (EPF) is:*  
 $EPF = \text{Availability} + \text{Cost of Loss} + \text{Lost Opportunity Cost}$

Based on the EPF, the ISO can devise the bidding structure for the generators shown as Figure 3.

In Figure 3, the parameter  $a_0$  denotes the availability bid in \$,  $m_1$  denotes the cost of loss bid and  $m_2$  the opportunity cost bid component, both in \$/MVar. Mathematically, the above representation can be written as follows:

$$BP_i = a_{0,i} + m_{1,i} \cdot Q_{1,i} + m_{2,i} \cdot Q_{2,i} \quad \forall Q_{base,i} \leq Q_{1,i} \leq Q_{A,i} \quad (2)$$

$$\quad \quad \quad \forall Q_{A,i} \leq Q_{2,i} \leq Q_{B,i}$$

given that,  $Q_{2,i} = 0 \quad \forall Q_{1,i} \neq Q_{A,i}$

In equation (2)  $BP_i$  is the bid-price from a generator  $i$ . Unlike the usual two-part tariff structures, this bidding model is different in the sense that the variable component  $Q_2$  (opportunity cost) comes into the picture only when the capacity quoted for  $Q_1$  is fully utilized.

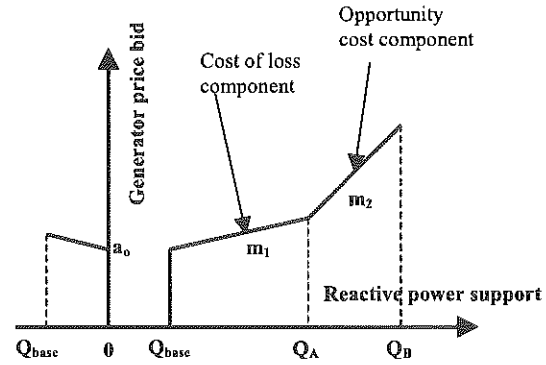


Figure 3. Bidding structure for synchronous generators considering three components of EPF

### 2.1.3 Effect of Generator Terminal Voltage Variation on Bid and Payment

In Figure 1 it was assumed that the generator terminal voltage remains constant. However, with variation in generator terminal voltage, the reactive power output available from a generator changes [5]. For example, if the operating point  $P_A$  is beyond the rated power  $P_R$ , i.e.,  $P_A > P_R$ , the reactive power capability of the generator will reduce when terminal voltage reduces. This is due to the fact that for  $P_A > P_R$ , the armature current heating limits determine the reactive power capability and which reduces as  $V_t$  reduces. This can be a very critical situation for the generator, the ISO, and ultimately for the system, since it may lead to voltage instability problems.

If a generator is operating at  $P_A > P_R$ , the ISO should not risk the system by requesting for reactive power from this generator. However, the generator stands to incur undesirable benefits in that- it operates at a highly profitable operating point, also receives the availability component of reactive power payment while does not participate in reactive power support. There should be certain instruments to tackle such situations. One possible way to tackle this situation is by setting  $a_0 = 0$  if  $P_A > P_R$ . This means that the generator is not paid the availability charge, and if and only if its reactive power service is used, it receives a payment.

On the other hand, if the generator is operating at  $P_A < P_R$ , the reactive power capability increases when the terminal voltage decreases because of decrease in field current carrying capacity. Due to the same reason, the reactive power capability reduces when terminal voltage increases. The ISO can choose to modify the opportunity cost payment taking into account the increase / decrease in the range of  $Q_A$  when voltage changes.

$$\begin{aligned} Q_A^{\text{Voltage Correction}} &= Q_A + \alpha & \forall V_i < 1.0 \\ Q_A^{\text{Voltage Correction}} &= Q_A - \beta & \forall V_i > 1.0 \end{aligned} \quad (3)$$

In equation (3)  $\alpha$  and  $\beta$  (in MVar) is the change in reactive power capability due to increase and decrease in generator terminal voltage respectively. The  $Q_A$  parameter and hence the  $Q_B$  parameter is appropriately modified and hence the payments can be made voltage dependent.

## 2.2 Optimal Reactive Power Procurement Model for ISO

With a reactive bid structure established, the ISO requires a proper criterion to determine the best offers and thus formulate its reactive power procurement plan. Unlike real power markets where bids are selected in ascending order of prices, reactive power markets need to consider the location aspects also because of the transmission loss considerations.

There are several critical issues concerning the development of a reactive power market. Some of them are discussed below.

- The mode of settlement of the reactive power market should be given utmost importance since location aspects can influence the reactive markets substantially and also induce market power with certain providers.
- If the selected providers are paid their bid offers, it can lead to extremely high bid price offers due to the less number of participants and their knowledge of strategic locations on the system.
- If the market is opened to all kinds of reactive service providers, then there may be more parties bidding at one location, thereby leading to a competitive market and hence rational bid price offers.
- If the bids and subsequent contracts are made for long term, then the generators cannot bid their reactive energy higher than the cost of alternative reactive power generation, which may lead to an efficient market.

We consider the problem of obtaining the optimal reactive power contracts, given that the mode of market settlement is decided, and assuming that the parties bid into the market rationally.

The reactive power providers can enter into long or short-term contracts with the ISO for reactive power provision. Contracted provisions involves payments to be made by the ISO, and it remains an objective of the ISO to procure the

service so as to minimise the total payment while meeting system constraints. Although this is a seemingly fair enough objective, the optimal selection can however result in increased losses in the system due to sub-optimal reactive power support and may even require curtailment of real power trades, both of which are undesirable. Increased energy loss requires the ISO to increase its procurement of *loss compensation services* from balance providers (generators or loads) involving additional payments. Thus, a *minimum payment* objective may not necessarily satisfy all the concerns of the ISO.

A two step method is proposed here to address the problem of optimal reactive power procurement considering both technical and financial efficiency of the ISO.

**Step-I:** The ISO determines the *marginal benefit* of each reactive power bid with respect to system losses.

**Step-II:** With the marginal benefit of each reactive power bid known to the ISO, it seeks to maximise a *societal advantage function* (SAF) formulated at this stage by incorporating the price bid offers.

### 2.2.1 Marginal Benefit from a Reactive Power Service

The marginal benefit to the system from one unit of reactive support at a bus can be determined from the dual of the system constraints of an appropriate OPF model representing the grid. Consider the following modified OPF:

**Minimize:** System transmission losses,

$$\text{Loss} = 0.5 \sum_{i,j} (G_{i,j} \times (V_i^2 + V_j^2 - 2V_i V_j \cos(\delta_i - \delta_j))) \quad (4)$$

$G_{i,j}$  is the conductance of line  $i-j$ , p.u.  
 $V_i$  bus voltage, p.u.  
 $\delta_i$  voltage angle, radians

**Subject to the following constraints:**

**Load flow equations:**

$$PG_i^{\text{con}} - \sum_{\text{gen}} XP_{i,\text{gen}} = \sum_j V_i V_j Y_{ij} \cos(\theta_{ij} + \delta_j - \delta_i) \quad (5)$$

$$Q_i - QD_i = - \sum_j V_i V_j Y_{ij} \sin(\theta_{ij} + \delta_j - \delta_i) \quad (6)$$

$PG_i^{\text{con}}$  Contracted real power generation at bus  $i$ , p.u.

$XP_{i,\text{gen}}$  Actual real power transaction between load at bus  $i$  and generators,  $\text{gen}$

$Q_i$  Reactive power support at bus  $i$ , p.u

$QD_i$  Reactive power demand at bus  $i$ , p.u

$Y_{ij}$  Element of network and admittance matrix, p.u

$\theta_{ij}$  Angle associated with  $Y$ , radians

**Bus voltage limits:**

$$\underline{V}_i \leq V_i \leq \bar{V}_i \quad (7)$$

**Limits on bilateral transactions:**

$$0 \leq XP_{i,\text{gen}} \leq XP_{i,\text{gen}}^{\text{con}} \quad (8)$$

$XP_{i,\text{gen}}^{\text{con}}$  is the contracted real power transactions by a load at bus  $i$  with a generator  $\text{gen}$ . The bilateral transactions are modeled using the method discussed in [6].

Reactive power capability limit of generators:

$$Q_i \leq \sqrt{\left(\frac{V_i E_{af}}{X_s}\right)^2 - (P_{G_i}^{can})^2} - \frac{V_i^2}{X_s} \quad (9)$$

$$Q_i \leq \sqrt{V_i I_a^2 - P^2} \quad (10)$$

(9) is applicable when the field heating limit acts as the upper limit (i.e. for  $P_A < P_R$ ) and (10) when the armature heating limit is applicable (i.e. for  $P_A > P_R$ ).

Lower limits on reactive power generation:

The under-excitation limit,  $Q_i^{Min}$ , is fixed *a priori* and hence the lower limit of reactive power generation is governed by the constraint,

$$Q_i^{Min} \leq Q_i \quad (11)$$

For the modified OPF described by equations ((4)–(11)), we define three sets of Lagrange multipliers associated with the three reactive power constraints ((6),(9),(11)) to derive important conclusions.

**2.2.2  $\lambda$ : dual of reactive balance constraint**

This parameter is obtained from the dual of the reactive power balance equation (6) and denotes the sensitivity of the system loss parameter to reactive demand changes at a bus.

$\lambda$  is in units of MW/MVAr denoting the change in MW loss per MVAr change in reactive demand.  $\lambda$  is multiplied with a cost parameter  $C_L$  (in \$/MW) denoting the valuation of reduced loss, to obtain the *marginal benefit*. Thus the marginal benefit to the ISO from a change in reactive demand at a bus is given by,

$$MB_i = \lambda_i \cdot C_L \quad \text{in } \$/\text{MVAr} \quad (12)$$

**2.2.3  $\gamma$ : dual of generator reactive capability constraint**

When the generator is operating at its reactive capability limits, it is of interest to know how the system will benefit if it chooses to increase its reactive generation beyond this point. The dual of the constraint ((9),(10)) obtained while minimizing system loss provides important information on these lines.

Thus,  $\gamma_{gen}$  indicates by how much the system loss will change for a unit change in generator reactive power capability.  $\gamma = 0$  indicates that the reactive power generation is below that specified by the field/armature current limits (i.e. if  $P = P_A$ ,  $Q < Q_A$ ). If  $\gamma < 0$ , it indicates that the system losses will reduce if reactive generation at the bus is increased (i.e.,  $Q > Q_A$ ), which is only possible by reducing real power generation. If  $\gamma > 0$ , it indicates that the system losses will increase if reactive generation is increased. It is then not desirable to provide additional reactive power by reducing real power generation.

The marginal benefit to the ISO from a generator supplying reactive power at its field/armature winding heating limit is given by,

$$MB_{gen} = \gamma_{gen} \cdot C_L \quad \$/\text{MVAr} \quad (13)$$

**2.2.4  $\mu$ : dual of reactive power constraint on lower limit**

This parameter is the dual associated with reactive constraint (11) applicable to reactive lower limits. Therefore,

$$MB_i = \mu_i \cdot C_L \quad \$/\text{MVAr} \quad (14)$$

**2.2.5. Societal Advantage Function (SAF) of the ISO**

Marginal benefit (MB) for reactive support at each bus, and bid parameters  $b_o$  and  $m_o$  for each reactive power provider, is now available to the ISO. Then, we can define the composite advantage function for the ISO as follows:

$$SAF = \sum_{gen} (C_L \cdot \lambda_{gen} - b_{o,gen}) \cdot Q_{2,gen} + \sum_{gen} \left( (C_L \cdot \gamma_{gen} - b_{o,gen}) \cdot Q_{3,gen} - \frac{1}{2} m_{o,gen} \cdot (Q_{3,gen} - Q_A)^2 \right) \quad (15)$$

$Q_2$  and  $Q_3$  represent regions II and III mentioned in Section 3.2, respectively. SAF in (15) represents the ISO's viewpoint, seeking contribution to system performance (in terms of loss reduction) from reactive power providers with lowest possible cost.

**SAF Maximization: Reactive Power Procurement**

Once the ISO's composite advantage function is constructed as in (15), the optimal reactive power procurement plan can be obtained from a second level model constructed using the information now available.

**Maximise:** Societal Advantage Function given by (15).

**Subject to the following constraints:**

Load Flow Equations ((5),(6))

Bus Voltage Limits (7)

Limit on Bilateral Transaction (8)

Reactive power generation limits

In Section- 3.1 we considered that the upper limit on reactive power is constrained by the field or armature heating limits. Now we consider that the generator is willing to reduce its real power output from  $P_A$  to  $P_B$  (refer Figure 1) in order to provide higher reactive power (for a price). The constraint (16) states that the maximum reactive support available from a generator is  $Q_B$  for an operating point,  $P_A$ .

$$Q_{Min,i} \leq Q_i \leq Q_{B,i} \quad (16)$$

Reactive power generation relational constraints

According to the three regions on the reactive power domain, discussed in Section 3.2, the reactive power output  $Q$  from a generator can be classified in any of the three components:  $Q_1$ ,  $Q_2$  or  $Q_3$ , to represent region I, II or III respectively. The governing algebraic relations between them can be written as follows.

$$Q_i = Q_{i_1} + Q_{i_2} + Q_{i_3} \quad (17)$$

$$W_{1i} \cdot Q_{\min i} \leq Q_{i_1} \leq W_{1i} \cdot Q_{Basei} \quad (18)$$

$$W_{2i} \cdot Q_{Basei} \leq Q_{i_2} \leq W_{2i} \cdot Q_{Ai} \quad (19)$$

$W_{3i} \cdot Q_{Ai} \leq Q_{i_3} \leq W_{3i} \cdot Q_{Bi}$

$$W_{1i} + W_{2i} + W_{3i} = 1$$

$W_1, W_2$  and  $W_3$  are binary variables for the discrete selection of a reactive component from any of the three regions. According to (19) only one of the binary variables can be selected. This automatically restricts that  $Q$  can be in only one of the bidding areas shown in Figure 3.

### 3. Design of a Frequency Regulation Market

There is considerable research literature available on traditional AGC. In such works, the definition of a control area is determined by the pooling arrangements of vertically integrated utilities or sometimes by their physical boundaries. All such control areas are interconnected by tie-lines.

In the context of deregulation, frequency control services and AGC has not received adequate attention. This is particularly so for the European electricity markets. There is some work, based on the NERC<sup>1</sup> directives, to address and formulate AGC problems in the US context. A detailed discussion of the potential system control problems and issues, associated with frequency control in deregulation, has been provided in [7].

In [8] and [9] a framework for price based operation of AGC in deregulated electricity markets has been developed. The work considers various type of AGC contracts such as bilateral transactions, poolco based transactions and area regulation contracts. In the bilateral transactions based AGC, gencos and discos negotiate bilateral contracts among each other and submit their contracted agreements to the Independent Contract Administrator (ICA). The genco sends a pulse to a generator to follow the predicted load, while remaining within the contracted value. The disco on the other hand monitors its load continuously and ensures that load following requirements are met according to contract requirements. In the poolco based contracts, the ICA settles the market based on the usual bid mechanisms of energy markets.

In the area-regulation contracts the ICA contracts with gencos to provide area regulation which is based on governor response characteristics.

It is important to explore mechanisms for frequency control in deregulated environment that are fair and equitable to both the service providers as well as the ISO. The service

providers ordinarily receive payments for providing the balance energy, as per agreement or schedule. However, there is no mention of frequency profile in these agreements. In the literature there are some applications of real-time frequency linked pricing to achieve improved system operation [10], [11]. Berger and Schweppe [10] demonstrated that real-time pricing in the presence of system dynamics could aid in load-frequency control. In [11] the pricing scheme suggested, gives the importing area a signal in terms of increased price for any increment in power drawn, from scheduled value. The increase in price is viewed as a penalty that discourages deviation from the scheduled power flow and thereby ensures grid discipline.

In this work we propose a new design of a frequency regulation service market which is activated by frequency-linked price signals from the ISO. The frequency regulation market structure is similar to a power pool where all frequency regulation service providers submit their bid-offers. The bid offers can be for both primary and secondary regulation services. A notable aspect of the bid offers is the linkage of price and quantity offers with the frequency.

The combined frequency regulation service market is simulated in two steps. The first step is to obtain the market price for primary and secondary regulation service from all bids provided to the ISO. The second step is the real-time activation of the services by the ISO based on signals, which are derived from the system frequency deviations. The framework of the combined regulation service scheme is shown in Figure 4.

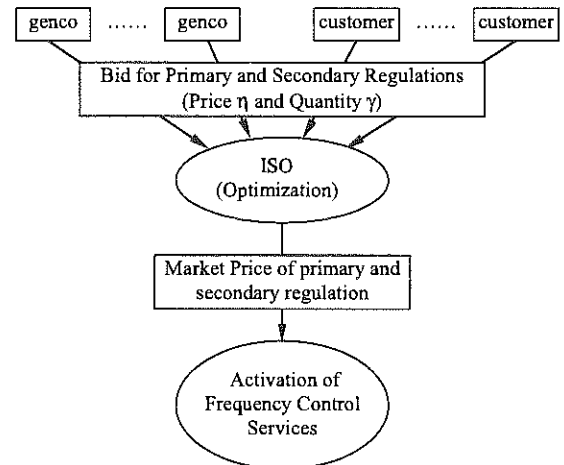


Figure 4. Framework of the Primary and Secondary Market

#### 3.1 Primary Regulation

The proposed scheme considers that  $\gamma_{PR,i}$  is the quantity (in p.u.MW) per unit market price of primary frequency

<sup>1</sup> North American Electric Reliability Council, USA.

regulation offered by a genco 'i'. Similarly,  $\eta_{PR,i}$  is the price (in \$/MWh) per unit of frequency deviation, offered by the genco 'i' (refer to Table 1).

Primary regulation services are activated by price signals, which are sent as soon as there is a frequency excursion in the system. The generating units contracting this service are prepared to increase or reduce their generation instantaneously. The regulation bid is in the form of  $\gamma_{PR,i}$  in p.u.MW/(\$/MWh), which indicates the regulating power on offer, per unit price. Therefore, if unit-1 offers to increase its generation by 1.95% for a 1% increase in price, and assuming the market price to be \$150/MWh, we have,

$$\gamma_i = \frac{1.95\% \text{ p.u.MW}}{150\$/\text{MWh} \cdot 1\%} = 0.013 \frac{\text{p.u.MW}}{\$/\text{MWh}}$$

Primary frequency regulation is achieved by the ISO by using these bids in conjunction with the primary frequency regulation market price,  $P_{PR}$ . The ISO determines  $P_{PR}$ , which is specified per unit of frequency excursion, from the generators' bid price parameters  $\eta_{PR}$  (\$/MWh-Hz). The generators contracted for the primary frequency regulation service then increase or decrease their generation as per the following relation:

$$\Delta P_{gi} = -P_{PR} \cdot \gamma_{PR,i} \cdot \Delta f_{area} \quad (20)$$

Table 1 Structure of Frequency-Linked Bid Offers for Primary Regulation

|                    | From gencos                        |                              | From Customers |       |
|--------------------|------------------------------------|------------------------------|----------------|-------|
|                    | Quantity                           | Price                        | Quantity       | Price |
| Primary Regulation | $\gamma_{PR,i}$<br>p.u.MW/(\$/MWh) | $\eta_{PR,i}$<br>(\$/MWh-Hz) | --             | --    |

The market is settled based on the price and quantity offers of all gencos, as discussed in the optimization model in the next section. The contracted gencos receive the market price  $P_{PR}$ , which is a frequency linked price determined from the bid price offers as well as the location of the providers.

A dynamic model demonstrating how gencos would participate and respond to the ISO's frequency-linked price signal, for primary frequency control is shown in Figure 5. As seen, the contracted gencos are available to provide  $\gamma_{PR,i}$  amount of primary control service which is activated by the primary frequency regulation market price signal  $P_{PR}$ .

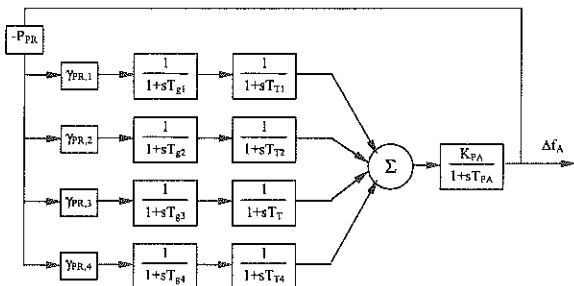


Figure 5. Dynamic Model of Primary Control

In Figure 5,  $T_{gi}$  ( $i=1,2,3,4$ ) is the speed-governor time-constant in seconds,  $T_{Ti}$  ( $i=1,2,3,4$ ) is the steam-chest time-constant in seconds.  $K_{pi}=1/D_j$  and  $T_{pj}=2H_j/fD_j$  ( $j$  = area A, area B) and  $D_j$  is the load-frequency constant and  $H_j$  is the inertia-constant of area  $j$ ,  $f$  is the nominal frequency.

### 3.2 Secondary Regulation

The secondary regulation service also includes bids from contractors, in addition to that from generators. The market is settled in the same way as that for primary regulation market. Table 2 shows the proposed structure of bid price and quantity for the participants of the secondary up and down regulation service market. The secondary regulation bid  $\eta_{SR}$  is the price (in \$/MWh) per unit of generation while  $\gamma_{SR}$  is the quantity offered (in p.u.MW) per unit of price.

Table 2 Structure of Bid Offers for Secondary Regulation

|                           | From gencos                               |                                      | From Customers                            |                                      |
|---------------------------|-------------------------------------------|--------------------------------------|-------------------------------------------|--------------------------------------|
|                           | Quantity                                  | Price                                | Quantity                                  | Price                                |
| Secondary Up Regulation   | $\gamma_{SR,i}^{UP}$<br>(p.u.MW/(\$/MWh)) | $\eta_{SR,i}^{UP}$<br>((\$/MWh)/MWh) | $\gamma_{SR,i}^{UP}$<br>(p.u.MW/(\$/MWh)) | $\eta_{SR,i}^{UP}$<br>((\$/MWh)/MWh) |
| Secondary Down Regulation | $\gamma_{SR,i}^{DN}$<br>(p.u.MW/(\$/MWh)) | $\eta_{SR,i}^{DN}$<br>((\$/MWh)/MWh) | $\gamma_{SR,i}^{DN}$<br>(p.u.MW/(\$/MWh)) | $\eta_{SR,i}^{DN}$<br>((\$/MWh)/MWh) |

**Secondary Regulation Service Offer From Generators:** These services are contracted in order to restore the system frequency to nominal (say 50 Hz) after a disturbance. This can be achieved either by increasing/reducing the area's total generation or by reducing / increasing the area's total demand. We first consider the case of generators contracting for secondary regulation services. The contracted generators respond to the price-linked control signal sent out by the ISO. It is assumed that the generators have different response rates to the ISO's price-linked control signal, which may depend on their technical characteristics or on economical criteria. Frequency control in this case can be achieved by controlling generation in Area-A through a real-time secondary regulation. The price-linked control signal is of the form:

$$\Delta \rho(t) = -P_{SR,area} \int ACE_{area}(t) dt \quad (21)$$

$P_{SR}$  is the area's secondary regulation price that is obtained from the market settlement model and shall be discussed subsequently. The generators contracted to respond to the above price-linked control signal increases or decreases their generation as per the following relation:

$$\Delta P_{gi} = \gamma_{SR,i} \cdot \Delta \rho \quad (22)$$

**Secondary Regulation Service Offer From Customers:** These services are also contracted to restore the system frequency to nominal after a disturbance. In this case, the contracted customers respond to the price-linked control signal sent by the ISO by increasing / reducing their demand. The customers have different response rates to the price signal,



which may depend on the load characteristics or on economical criteria. In this case frequency control is achieved by controlling the demand in real-time. The price-linked signal is the same, as described in Equation (21). The loads contracted to respond to this signal, increase or decrease their load as per the following relation:

$$\Delta P_{di} = -\gamma_{SR,Di} \cdot \Delta \rho \quad (23)$$

Figure 6 shows the dynamic model of a two-area interconnected power system with the proposed primary and secondary control mechanisms.

### 3.3 Simulation Results of Primary and Secondary Regulation

Now the selected sets of primary and secondary regulation service providers in two control areas are incorporated for the combined frequency regulation simulation. Two perturbations are considered in Area-A during the 150 seconds simulation. The first is a 1% increase in load at time  $t=0$  and the second is a 5% increase in load at time  $t=12$  second.

Figure 7 shows the plot of the frequency following the two perturbations with primary and secondary regulation services activated. It is seen that the frequency is brought back to the nominal (50 Hz) through secondary regulation in about 2 minutes.

### 4. Conclusions

This paper attempts to examine the various issues involved in electric power ancillary services in the context of power sector deregulation. Particular emphasis is on the study of reactive power service and frequency regulation service, and how they are managed by the system operator in deregulated markets.

We develop a reactive power market structure based on the analysis of reactive power costs from synchronous generators. A bidding structure is incorporated with an OPF model and a two-step optimization procedure is used to determine the optimal reactive power contracts. The optimization scheme takes into account the marginal benefits from reactive power support at a system bus vis-à-vis the payment to be made by the ISO, by way of reactive power procurement.

Subsequently, we propose a frequency-linked bidding structure for the frequency regulation service market. The participating parties are envisaged to respond to price signals sent out by the ISO, based on their bid offers. An optimization scheme has been developed, both for primary and secondary regulation services, to address the ISO's problem of determining the best contracts. Further, a dynamic simulation model is developed for a two-area

interconnected power system that incorporates the above features of frequency regulation services to examine the performance of the optimum regulation contracts.

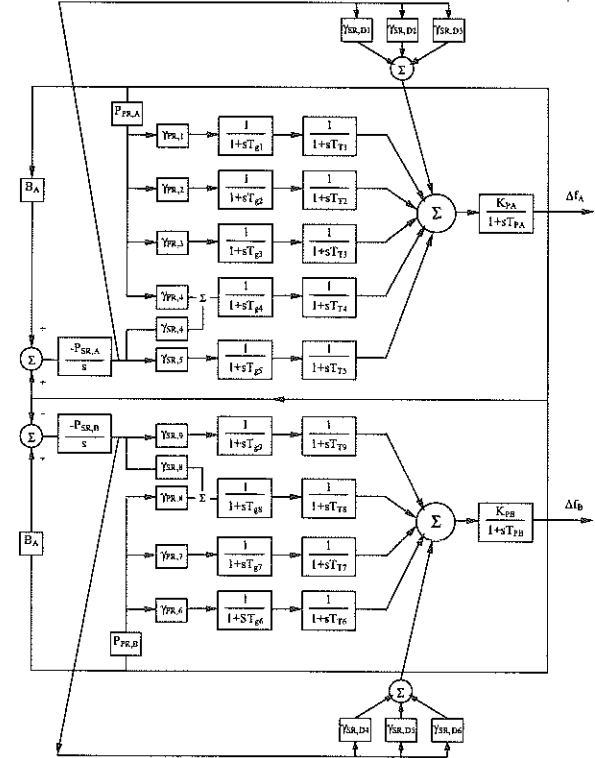


Figure 6. Dynamic Model of Primary and Secondary Control

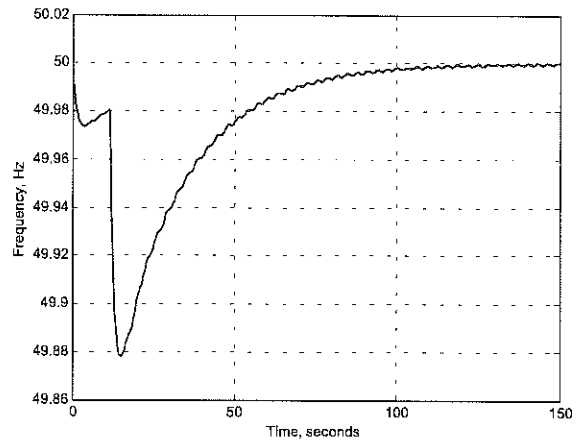


Figure 7 Area-A Frequency Plot With Primary and Secondary Regulation

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## Modeling of load participation in competitive electricity markets

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### Abstract

This paper is concerned with the assessment of the role of load participation in competitive electricity markets. Using the pool paradigm model, we represent the loads' ability to react to price signals by an appropriate demand curve that expresses the willingness to pay for each level of real power desired. We construct a rather general model of price responsive load using demand elasticity information for the real power demand and we represent the reactive power demand as an affine function of the real power. The deployment of the load models in OPF applications allows the investigation of the interaction between real and reactive nodal prices and demand prices.

We use these models to assess the impacts of the participation of loads and compare them to those without load participation. The comparison, in terms of meaningful microeconomic metrics, including average prices, price volatility and consumer, producer and merchandise surpluses, indicates that, in the new competitive electricity markets, the demand side participation is as important as the supply side and plays a fundamental role in attaining market efficiency and attenuating price spikes. The reactive load model is particularly effective for the realistic representation of the economic efficiency in competitive markets. We present representative numerical results on the IEEE 30-bus based system that illustrate the importance of load modeling on the economic performance.

### I. Introduction

The demand side plays a major role in determining the price of electricity in the market. In the old regime the demand was forecasted and then assumed fixed within a certain timeframe; increases in the demand level corresponded to the dispatching of more expansive generators and, hence, to higher prices. In the new competitive environment the importance of the demand is even more marked. The demand of each load is expressed in terms of willingness to pay, which relates the real power demand with the price that the load is willing to pay to have that demand satisfied. The degree of price responsiveness of total demand to price plays a major role in determining the prices of electricity and the market outcomes as happens in others commodity markets.

Unlike other markets in which no or few constraints are imposed on the meeting of demand and offer, in the electricity markets severe physical and operational constraints must be observed to guarantee a feasible and reliable operation of the

system. When one or more physical, operational, or policy constraints - e.g., line flow limits, voltage admissible bands, stability limits - under which the grid operates are violated, the system experiences congestion and some action needs to be undertaken for its relief [1][2]. The constraints that are considered depend on the level of detail adopted in the network modeling and are, to a certain extent, arbitrary, with various ramifications on the market [3][4]. Congestion may cause different prices for generators and loads at different locations and the rise of congestion charges [5],[6]. Depending principally on the real and reactive load level of the system, situations with lack or excess of reactive power may arise in the grid leading to the violation of one or more voltage and/or reactive power limits. Hence, the operation of the power system in a competitive context need to take carefully into account also the reactive power demand and the associated price signals [7]-[10].

Congestion, generally, results in a decrease in market efficiency and in a decrease in the amount of power traded; moreover, it may result, in certain cases, in marked price volatility and leads to price spikes.

The crucial need to comply with the system constraints while allowing for market competition requires the introduction of a Independent Grid Operator (IGO) with different responsibilities and level of authority in different jurisdictions. The IGO is responsible for determining the necessary actions to ensure that no violation of the various grid constraints occurs and to determine the transmission usage charges.

One of the emerging market structure in the new regime is the *pool paradigm*. This paradigm merges the grid operator's coordination role with a centralized economic dispatch function. All the power traded goes through the pool as the pool is the sole buyer and seller of electricity. The pool determines the "optimum" solution by solving a *centralized economic dispatch* problem taking into account the network constraints, so avoiding implicitly the occurrence of congestion in the system. The economic dispatch is undertaken through an optimal power flow (OPF) which considers the offers of the suppliers and the bids of the demanders and whose objective is to maximize the social surplus. Load responsiveness gives to the IGO additional decision variables that are particularly important during congestion; the possibility to vary the load demand at each bus may alleviate the congestion and reduce the impacts associated.

In an unconstrained market the solution of the optimization problem attains the maximum efficiency and the nodal demand prices and nodal generator prices at each bus are equal. In this

situation a *market clearing price* (MCP) is defined. When the network is considered, congestion may arise, and the corresponding optimum results in a lower market efficiency along with different nodal demand and generator prices at each bus.

In this paper we propose a rather general load model, with reactive power behavior considered, to represent the demand side participation in competitive markets. The impacts of the demand side participation on the market performances are investigated, in a market based on a pool paradigm.

This paper consists of four additional Sections. In Section II, a general model of price responsive load with reactive power demand considered is presented. Section III introduces the general framework to analyze the market performance in presence of load participation while, in Section IV, the results of numerical studies are presented to illustrate the main economic impacts of the load participation in the pool paradigm and some general findings are summarized. In the last Section some conclusive remarks are drawn.

## II. Price-responsive load model

In the competitive markets the load demand is expressed in terms of willingness to pay, which relates the amount of real power absorbed to the energy unit price. Reactive power is needed, as well, by the loads, even if it is not explicitly traded in the energy market. The reactive power flows influence the optimum due to the real power losses they induce and are of the utmost importance in achieving a feasible operation of the system. Hence, the load behavior, in terms of reactive power absorption, needs to be explicitly included in the load model.

For a load at bus  $d$ , we describe its price responsiveness with a demand function  $f_d(\cdot)$  which expresses the nodal demand price  $v_d$  as function of the demand. The nodal demand price  $v_d$  corresponds to the unit energy price that the load is willing to pay to purchase  $D_d$  MW of power. The function  $f_d(\cdot)$  represents the bid that the load  $d$  submits to the market; it is a decreasing function, with the unit price that the load is willing to pay decreasing as the power demand increases. In a perfect competition market, a customer would bid its marginal benefit to maximize its net benefit [11] and so, under those assumptions, the customer's benefit may be derived using:

$$B_d(D_d) = \int_{D_d^{\min}}^{D_d} f_d(\zeta) d\zeta + B_d(D_d^{\min}) \quad (1)$$

where  $D_d^{\min}$  is the minimum real power that the load is willing to buy. For the demand function, we define the elasticity  $\epsilon$  of the demand as [11]:

$$\epsilon = e(D_d) = - \frac{1}{\frac{df_n}{dD_d} \frac{D_d}{v_d}} \quad (2)$$

In this paper we assume, as demand function  $f_d(\cdot)$ , an affine function of the real power demand  $D_d$ :

$$v_d = f_d(D_d) = \beta_{2d} D_d + \beta_{1d} \quad (3)$$

The function is defined within a range  $[D_d^{\min}, D_d^{\max}]$ , whose ends represent the minimum and the maximum real power that the load is willing to buy. The bid curve is depicted in Fig. 1. The price  $v_d$  is a marginal price because it corresponds to the price of the last unit of power absorbed. That price is also a unit price since it applies to all the energy bought.

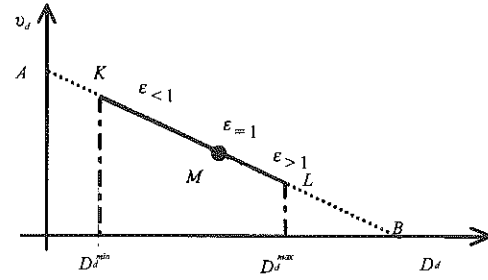


Fig. 1 – Affine bid function

The elasticity of the demand for the model of Eq. (3) is:

$$\epsilon = e(D_d) = - \frac{\beta_{1d}}{\beta_{2d} D_d} - 1 \quad (4)$$

and the benefit function defined in (1) becomes:

$$B_d(D_d) = \frac{1}{2} \beta_{2d} (D_d)^2 + \beta_{1d} D_d + \beta_{0d} \quad (5)$$

It follows from (4) that the demand elasticity depends on the demand level  $D_d$ ; different points on the curve, corresponding to different demand values, are characterized by different elasticity values. Three different qualitative behaviors of the elasticity may be detected: inelastic, elastic and unit elasticity [12]. With reference to Fig. 1, we assume the point  $M$  as the middle point of the segment  $AB$ . The points on the bid curve belonging to the segment  $KM$  are characterized by an elasticity value lower or equal to one, the points belonging to segment  $ML$  are characterized by an elasticity value greater or equal to one. While the point  $M$  corresponds exactly to a unit elasticity value. The different qualitative behaviors may be interpreted as follows. An *elastic demand* ( $\epsilon > 1$ ) implies that the variation in the price causes a variation in the demand more than proportional to the price variation while an *inelastic demand* ( $\epsilon < 1$ ) means that the variation in the price causes a variation in the demand less than proportional to the price variation. A *unity elasticity demand* ( $\epsilon = 1$ ) means that the variation in the price causes a variation in the demand proportional to the price variation.

Due to the variation of the elasticity along an affine demand function, the definition of the demand in terms of elasticity must be done with reference to a specified demand level. We characterize the price responsiveness of a load defining its demand curve through three parameters:

1. a reference demand:  $D_d^r$
2. a reference price:  $v_d^r$
3. a load elasticity at the reference point  $(v_d^r, D_d^r)$ :  $\epsilon_d^r$

The point  $(v_d', D_d')$  may be considered as a desired point indicated by the load to the market. The elasticity value at that point expresses the willingness of the load to change his preferred point. From a geometrical point of view the elasticity that characterizes the demand function may be seen as the slope of the bid function at the reference point. As a limit cases we consider the demand curves with, respectively, infinite and zero elasticity, as shown in Fig. 2. For an infinite elasticity the price that the load is willing to pay is fixed and, at that price, it buys any amount of power. For a zero elasticity value, the power demand is fixed and the load is willing to pay any price to have its demand met.

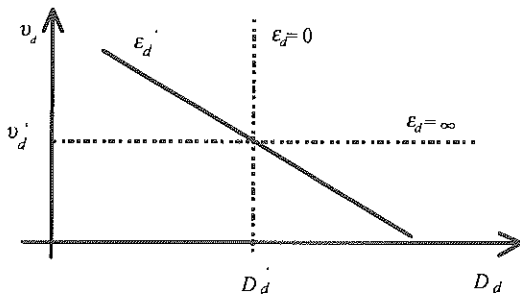


Fig. 2 - Elastic load model representation

The coefficients of the bid curve may be expressed as a function of the three reference parameters as:

$$\beta_{2d} = -\frac{v_d'}{\epsilon_d D_d'}$$

$$\beta_{1d} = v_d' \left( 1 + \frac{1}{\epsilon_d} \right)$$

and the load bid curve may be expressed as:

$$v_d = f_d(D_d) = -\frac{v_d'}{\epsilon_d} \left( \frac{1}{D_d'} D_d - (\epsilon_d + 1) \right)$$

The load behavior, in terms of reactive power absorption, may be modeled assuming the reactive power  $Q_d^d$  as a function the real power demand  $D_d$ :

$$Q_d^d = \xi_j(D_d) \quad (6)$$

The dependence of reactive power demand on real demand may be modeled with an affine function:

$$Q_d^d = Q_d^0 + w_d \cdot D_d \quad (7)$$

with:

$$D_d^{\min} \leq D_d \leq D_d^{\max} \quad (8)$$

From eq. (7) some particular cases of reactive load behavior may be derived:

- if  $Q_d^0 = w_d = 0 \Rightarrow Q_d^d = 0$ , the load is a purely real power load

- if  $w_d = 0 \Rightarrow Q_d^d = Q_d^0$ , the load is a constant reactive power load
- if  $Q_d^0 = 0$  and  $w_d = \tan \phi_d \Rightarrow Q_d^d / D_d = \tan \phi_d$ , the load is a constant power factor load.

### III. Framework

The dispatching in a pool model is done through an optimization procedure that takes into account all the considered system constraints and, hence, the congestion avoidance is implicitly considered in this phase [13].

We assume:

|                 |                                        |
|-----------------|----------------------------------------|
| $g$             | generation bus index                   |
| $d$             | load bus index                         |
| $\mathcal{N}$   | set of the $N$ buses of the system     |
| $\mathcal{G}$   | set of the $N_g$ buses with generators |
| $\mathcal{D}$   | set of the $N_d$ buses with loads      |
| $\mathcal{N}_L$ | set of the $N_l$ lines                 |
| $V_k$           | voltage at bus $k$                     |
| $\theta_k$      | bus voltage angle at bus $k$           |
| $P_g$           | real generator power at bus $g$        |
| $Q_g^g$         | reactive generator power at bus $g$    |
| $D_d$           | real load power at bus $d$             |
| $Q_d^d$         | reactive loads power at bus $d$        |
| $S_l$           | apparent line power on line $l$        |
| $\rho_g$        | generation offer price at bus $g$      |
| $v_d$           | load bid price at bus $d$              |

The offer of generator at bus  $g$  is:

$$\rho_g = \alpha_{2g} P_g + \alpha_{1g} \quad g \in \mathcal{G} \quad (9)$$

from (9) we derive:

$$C_g(P_g) = \frac{1}{2} \alpha_{2g} (P_g)^2 + \alpha_{1g} P_g + \alpha_{0g} \quad (10)$$

The optimization problem is formulated as follows. The objective function to be minimized is:

$$\min \left[ \sum_{g \in \mathcal{G}} C_g(P_g) - \sum_{d \in \mathcal{D}} B_d(D_d) \right] \quad (11)$$

The optimization problem is submitted to the following equality constraints:

active power balances (dual variables  $\lambda_k^a$ ):

$$-P_k + D_k + \sum_{m=1}^N V_k V_m Y_{km} \cos(\theta_k - \theta_m - \phi_{km}) = 0 \quad k \in \mathcal{N} \quad (12)$$

reactive power balances (dual variables  $\lambda_k^r$ ):

$$-Q_k^g + Q_k^d + \sum_{m=1}^N V_k V_m Y_{km} \sin(\theta_k - \theta_m - \phi_{km}) = 0 \quad k \in \mathcal{N} \quad (13)$$

reactive load model (dual variables  $\gamma_j$ ):

$$Q_d^d = \psi_j(D_d) \quad d \in \mathcal{D} \quad (14)$$

The real and reactive power balances at bus  $k$  are associated respectively with the dual variables  $\lambda_k^a$  and  $\lambda_k^r$  that express the

sensitivities of the objective to an injection of real or reactive power at bus  $k$  and may be interpreted as real and reactive nodal prices (NPs).

The inequality constraints for the optimization problem are:

$$\begin{aligned}
 &\text{bus voltage limits (dual variables } \mu_k^v, \eta_k^v) \\
 &V_k - V_k^{\max} \leq 0 \quad \leftrightarrow \quad \mu_k^v \geq 0 \\
 &-V_k + V_k^{\min} \leq 0 \quad \leftrightarrow \quad \eta_k^v \geq 0 \quad k \in \mathcal{N} \\
 &\text{generation limits (dual variables } \mu_g^g, \eta_g^g, \mu_g^{qg}, \eta_g^{qg}) \\
 &P_g - P_g^{\max} \leq 0 \quad \leftrightarrow \quad \mu_g^g \geq 0 \\
 &-P_g + P_g^{\min} \leq 0 \quad \leftrightarrow \quad \eta_g^g \geq 0 \quad g \in \mathcal{G} \\
 &Q_g^g - Q_g^{\max} \leq 0 \quad \leftrightarrow \quad \mu_g^{qg} \geq 0 \\
 &-Q_g^g + Q_g^{\min} \leq 0 \quad \leftrightarrow \quad \eta_g^{qg} \geq 0 \quad g \in \mathcal{G} \\
 &\text{line current limits (dual variables } \mu_l^i) \\
 &-h_l(v, \theta) + S_{l\max} \leq 0 \quad \leftrightarrow \quad \mu_l^i \geq 0 \quad l \in \mathcal{N}_l \\
 &\text{real demand limits (dual variables } \mu_d^d, \eta_d^{pd}) \\
 &D_d - D_d^{\max} \leq 0 \quad \leftrightarrow \quad \mu_d^d \geq 0 \\
 &-D_d + D_d^{\min} \leq 0 \quad \leftrightarrow \quad \eta_d^{pd} \geq 0 \quad d \in \mathcal{D}
 \end{aligned}$$

The nodal demand price  $v_d$  and the nodal generator price  $p_g$  may be expressed in terms of the dual variables associated with the equality and inequality constraints of the optimization problem. We represent explicitly the relationships between the nodal demand, the nodal generation prices and the NPs at the optimum. From the Kuhn-Tucker conditions, for the optimization problem considered, we derive:

$$\rho_g - \lambda_g^a - \eta_g^s + \mu_g^s = 0 \quad g \in \mathcal{G} \quad (15)$$

$$-v_d + \lambda_d^a - \eta_d^d + \mu_d^d + \lambda_d^r \frac{dQ_d}{dD_d} = 0 \quad d \in \mathcal{D} \quad (16)$$

$$\lambda_d^r - \gamma_d = 0 \quad d \in \mathcal{D} \quad (17)$$

The nodal generation and demand prices are then expressed by:

$$\rho_g = \lambda_g^a + \eta_g^s - \mu_g^s \quad g \in \mathcal{G} \quad (18)$$

$$v_d = \lambda_d^a + \lambda_d^r \frac{dQ_d}{dD_d} - \eta_d^d + \mu_d^d \quad d \in \mathcal{D} \quad (19)$$

Hence, the nodal demand price  $v_d$  is equal to real NP only if the real power demand limits are not activated and the reactive power does not depend on the real one or the reactive NP is zero.

Some useful economic metrics are:

*consumer surplus:*

$$S^D(D_d) \triangleq \sum_{d \in \mathcal{D}} S_d^D = \sum_{d \in \mathcal{D}} [B_d(D_d) - v_d D_d] \quad (20)$$

*producer surplus:*

$$S^G(P_g) \triangleq \sum_{g \in \mathcal{G}} S_g^G = \sum_{g \in \mathcal{G}} [\rho_g P_g - C_g(P_g)] \quad (21)$$

*merchandise surplus:*

$$S^M(D_d, P_g) \triangleq \sum_{d \in \mathcal{D}} v_d D_d - \sum_{g \in \mathcal{G}} \rho_g P_g \quad (22)$$

The *social surplus*  $S^S$  is the negative of the objective of the optimization problem and may be expressed as [14]:

$$\begin{aligned}
 S^S &= \sum_{d \in \mathcal{D}} B_d(D_d) - \sum_{g \in \mathcal{G}} C_g(P_g) \\
 &= \sum_{d \in \mathcal{D}} [B_d(D_d) - v_d D_d] + \sum_{g \in \mathcal{G}} [\rho_g P_g - C_g(P_g)] + \\
 &\quad + \sum_{d \in \mathcal{D}} v_d D_d - \sum_{g \in \mathcal{G}} \rho_g P_g = S^D + S^G + S^M
 \end{aligned} \quad (23)$$

Demand elasticity, in markets with network constraints, affects the optimum determined by the IGO and impacts the market performances. The microeconomic metrics defined by eqs (20),(21),(22) and (23) may be used to evaluate the impact of demand responsiveness. The consumer surplus represents the difference between the total benefits associated with the power purchased and the total expenditures; it tends to infinity for elasticity tending to zero and it tends to zero for elasticity tending to infinity. The producer surplus represents the total profits of the generators plus the total fixed cost. The merchandise surplus is the money collected or paid by a virtual merchant who would purchase the power from generators to sell to loads and may be interpreted as a loss of efficiency of market. With losses neglected and no constraint violation, nodal demand and generator prices would be equal at each bus to the MCP and the total power produced by the generators would be exactly equal to that withdrawn by the loads, with a zero merchandise surplus. If the network is considered, the losses cause different nodal generator and demand prices at each bus and produce a positive merchandise surplus. In a lossless system, with congestion due to any kind of constraint violation, the prices are different and merchandise surplus may be either positive or negative. If the two effects, losses and congestion, are considered jointly, merchandise surplus is usually greater than zero. The social surplus is a measure of the market efficiency; it attains its maximum value for an unconstrained market without network consideration, while, for congested system, its value is reduced. In a lossless system, for elasticity tending to infinite, the consumer and the merchandise surpluses tend to zero and, hence, the social surplus tends to be coincident with the producer surplus.

Additional appropriate economic metrics for market performance analysis are:

*weighted average nodal demand price*, defined as:

$$\bar{v} = \sum_d v_d D_d / \sum_d D_d \quad d \in \mathcal{D} \quad (24)$$

*weighted average nodal generation price*, defined as:

$$\bar{\rho} = \sum_g \rho_g P_g / \sum_g P_g \quad g \in \mathcal{G} \quad (25)$$

The nodal price volatility may be evaluated through the *standard deviation of nodal demand prices*.

#### IV. Numerical Studies

We provide some numerical results of the studies on a IEEE 30-bus-based system, in a pool paradigm contest. The objective is to show the market ramifications of demand responsiveness. The role of load elasticity and the impact of the load modeling will be assessed through a number of examples. The cost (benefit) functions of the system have been scaled to give unity nodal price for all generators (loads) in the lossless unconstrained case, at the dispatched power. The load at each bus is modeled with constant power factor. The voltage at each bus has been forced within the range [0.95, 1.05] pu.

We will first consider the impacts of the constraints in a lossless system in terms of nodal demand prices behavior and economic metrics, for different values of uniform load elasticity. Then the losses will be considered and their impacts will be shown. The effects of the reactive load model will be highlighted introducing, for comparison, a constant reactive power load. At the end of the Section, we summarize the main findings derived from our studies. The values of the market metrics for the different cases studied are reported in Table 1, where  $P_{tot}$  and  $D_{tot}$  represent respectively the total power generation and the total power demand.

##### A. Base case

The base case corresponds to the lossless unconstrained market solution; in this case no constraints are activated and the solution at the optimum is exactly the same that would have been found by intersecting the aggregate demand and offer curves. The results, in terms of nodal real and reactive prices and nodal demand prices, are summarized in Table 2. The real NPs at each bus are the same and are equal to the nodal demand prices. Hence, a MCP, equal to one, does exist. The reactive NPs are null at each bus, meaning that the reactive power does not affect the objective. The value of the economic metrics are summarized in Table 1. In this case the market attains its maximum efficiency, corresponding to a social surplus of 1.346 \$/h, that is divided among producers and consumers; the merchandise surplus is zero since each nodal

generation and demand price is equal to the MCP and losses are disregarded. The power traded on the market is maximum and equal to 1.892 pu.

This case is the reference case for considering the impacts of network consideration in a market based on a pool paradigm. In the following examples different type of constraints are bought in and their impacts are shown.

Table 1 - Values of the metrics for the different test cases

| case | $\epsilon$ | $P_{tot}$ | $D_{tot}$ | losses [%] | $S^G$ | $S^D$ | $S^M$  | $S^S$ | $\bar{\rho}$ | $\bar{v}$ | $\sigma_v$ |
|------|------------|-----------|-----------|------------|-------|-------|--------|-------|--------------|-----------|------------|
| A    | 1          | 1.892     | 1.892     | 0.000      | 0.400 | 0.946 | 0.000  | 1.346 | 1.000        | 1.000     | 0.000      |
|      | 0          | 1.892     | 1.892     | 0.000      | 0.327 | -     | 0.107  | -     | 0.983        | 1.040     | 0.150      |
|      | 0.2        | 1.871     | 1.871     | 0.000      | 0.328 | 4.629 | 0.139  | 5.097 | 0.976        | 1.051     | 0.160      |
|      | 1          | 1.846     | 1.846     | 0.000      | 0.338 | 0.909 | 0.078  | 1.326 | 0.973        | 1.015     | 0.089      |
|      | 5          | 1.852     | 1.852     | 0.000      | 0.367 | 0.187 | 0.028  | 0.582 | 0.983        | 0.998     | 0.032      |
| B    | $\infty$   | 1.892     | 1.892     | 0.000      | 0.400 | 0.000 | 0.000  | 0.400 | 1.000        | 1.000     | 0.000      |
|      | 0          | 1.892     | 1.892     | 0.000      | 0.374 | -     | 0.372  | -     | 0.999        | 1.195     | 0.250      |
|      | 0.2        | 1.879     | 1.879     | 0.000      | 0.394 | 4.666 | 0.069  | 5.129 | 0.997        | 1.034     | 0.038      |
|      | 1          | 1.880     | 1.880     | 0.000      | 0.396 | 0.934 | 0.016  | 1.346 | 0.998        | 1.006     | 0.009      |
|      | 5          | 1.884     | 1.884     | 0.000      | 0.397 | 0.188 | 0.004  | 0.589 | 0.999        | 1.001     | 0.002      |
| C    | $\infty$   | 1.892     | 1.892     | 0.000      | 0.400 | 0.000 | 0.000  | 0.400 | 1.000        | 1.000     | 0.000      |
|      | 0          | 1.892     | 1.892     | 0.000      | 0.574 | -     | -0.329 | -     | 1.124        | 0.950     | 0.160      |
|      | 0.2        | 1.940     | 1.940     | 0.000      | 0.424 | 4.978 | -0.279 | 5.123 | 1.013        | 0.869     | 0.140      |
|      | 1          | 1.937     | 1.937     | 0.000      | 0.416 | 0.993 | -0.064 | 1.344 | 1.008        | 0.975     | 0.033      |
|      | 5          | 1.922     | 1.922     | 0.000      | 0.410 | 0.195 | -0.016 | 0.589 | 1.005        | 0.997     | 0.008      |
| D    | $\infty$   | 1.892     | 1.892     | 0.000      | 0.400 | 0.000 | 0.000  | 0.400 | 1.000        | 1.000     | 0.000      |
|      | 1          | 1.827     | 1.827     | 0.000      | 0.358 | 0.886 | 0.093  | 1.337 | 0.980        | 1.031     | 0.600      |
|      | 0          | 1.917     | 1.892     | 1.314      | 0.397 | -     | 0.017  | -     | 0.980        | 1.003     | 0.012      |
|      | 0.2        | 1.915     | 1.890     | 1.311      | 0.396 | 4.719 | 0.025  | 5.140 | 0.980        | 1.006     | 0.013      |
|      | 1          | 1.908     | 1.883     | 1.289      | 0.394 | 0.937 | 0.024  | 1.356 | 0.979        | 1.004     | 0.013      |
| E    | 5          | 1.897     | 1.874     | 1.213      | 0.391 | 0.186 | 0.022  | 0.600 | 0.977        | 1.001     | 0.012      |
|      | $\infty$   | 1.978     | 1.970     | 0.404      | 0.423 | 0.000 | 0.005  | 0.428 | 0.993        | 1.000     | 0.000      |
|      | 0          | 1.917     | 1.892     | 1.314      | 0.397 | -     | 0.017  | -     | 0.980        | 1.003     | 0.012      |
|      | 0.2        | 1.915     | 1.890     | 1.311      | 0.396 | 4.719 | 0.025  | 5.140 | 0.980        | 1.006     | 0.013      |
|      | 1          | 1.908     | 1.883     | 1.289      | 0.394 | 0.937 | 0.024  | 1.356 | 0.979        | 1.004     | 0.013      |
| F    | 5          | 1.897     | 1.874     | 1.213      | 0.391 | 0.186 | 0.022  | 0.600 | 0.977        | 1.001     | 0.012      |
|      | $\infty$   | 1.978     | 1.970     | 0.404      | 0.423 | 0.000 | 0.005  | 0.428 | 0.993        | 1.000     | 0.000      |

##### B. Line flow limit impacts

This case considers the activation of a line flow equal to 0.18 pu on line 4-6. In Table 3, the impacts of that activation on prices are illustrated. Due to the activation of the constraint, the real NPs become different at each bus and the reactive NPs may be positive or negative. Consequently, the nodal demand prices may be greater or lower than real NPs because of the reactive

Table 2 - Real and reactive nodal prices and nodal demand prices for the lossless unconstrained case (case A)

| nodal<br>variables | bus   |       |       |       |       |       |       |       |       |       |       |       |       |       |       |       |       |       |       |       |
|--------------------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|
|                    | 2     | 3     | 4     | 7     | 8     | 10    | 12    | 14    | 15    | 16    | 17    | 18    | 19    | 20    | 21    | 23    | 24    | 26    | 29    | 30    |
| $D_d$              | 0.217 | 0.024 | 0.076 | 0.228 | 0.300 | 0.058 | 0.112 | 0.062 | 0.082 | 0.035 | 0.090 | 0.032 | 0.095 | 0.022 | 0.175 | 0.032 | 0.087 | 0.035 | 0.024 | 0.106 |
| $\lambda^a_d$      | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 |
| $\lambda^r_d$      | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| $v_d$              | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 |

Table 3 - Real and reactive nodal prices and nodal demand prices for the lossless case with a line flow limit on line 4-6 -  $\epsilon = 1$  (case B)

| nodal<br>variables | bus   |        |        |       |       |       |        |        |        |        |       |       |       |       |       |       |       |       |       |       |
|--------------------|-------|--------|--------|-------|-------|-------|--------|--------|--------|--------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|
|                    | 2     | 3      | 4      | 7     | 8     | 10    | 12     | 14     | 15     | 16     | 17    | 18    | 19    | 20    | 21    | 23    | 24    | 26    | 29    | 30    |
| $D_d$              | 0.228 | 0.029  | 0.091  | 0.205 | 0.247 | 0.056 | 0.121  | 0.066  | 0.086  | 0.036  | 0.089 | 0.033 | 0.095 | 0.022 | 0.170 | 0.033 | 0.086 | 0.034 | 0.023 | 0.099 |
| $\lambda^a_d$      | 0.948 | 0.833  | 0.814  | 1.073 | 1.104 | 1.029 | 0.931  | 0.945  | 0.956  | 0.973  | 1.012 | 0.981 | 0.997 | 1.005 | 1.027 | 0.982 | 1.017 | 1.044 | 1.062 | 1.062 |
| $\lambda^r_d$      | 0.000 | -0.066 | -0.080 | 0.060 | 0.073 | 0.011 | -0.015 | -0.011 | -0.008 | -0.003 | 0.007 | 0.001 | 0.003 | 0.005 | 0.002 | 0.000 | 0.000 | 0.001 | 0.000 | 0.000 |
| $v_d$              | 0.948 | 0.800  | 0.797  | 1.101 | 1.177 | 1.033 | 0.921  | 0.942  | 0.954  | 0.971  | 1.017 | 0.981 | 0.998 | 1.007 | 1.028 | 0.982 | 1.017 | 1.044 | 1.062 | 1.062 |

Table 4 - Real and reactive nodal prices and nodal demand prices for the lossless case with a minimum voltage limit at bus 10 -  $\varepsilon = 1$  (case C)

| nodal variables | bus   |       |       |       |       |       |       |       |       |       |       |       |       |       |       |       |       |       |       |       |
|-----------------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|
|                 | 2     | 3     | 4     | 7     | 8     | 10    | 12    | 14    | 15    | 16    | 17    | 18    | 19    | 20    | 21    | 23    | 24    | 26    | 29    | 30    |
| $D_d$           | 0.218 | 0.024 | 0.076 | 0.227 | 0.297 | 0.057 | 0.111 | 0.062 | 0.082 | 0.035 | 0.087 | 0.032 | 0.094 | 0.022 | 0.174 | 0.032 | 0.087 | 0.035 | 0.024 | 0.106 |
| $\lambda_d^a$   | 0.997 | 0.998 | 0.998 | 0.998 | 0.998 | 1.000 | 0.998 | 0.999 | 0.999 | 0.999 | 1.000 | 1.000 | 1.001 | 1.000 | 0.999 | 0.999 | 0.999 | 0.999 | 0.998 | 0.998 |
| $\lambda_d^r$   | 0.000 | 0.008 | 0.010 | 0.011 | 0.013 | 0.056 | 0.012 | 0.013 | 0.013 | 0.031 | 0.049 | 0.028 | 0.037 | 0.042 | 0.012 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| $v_d$           | 0.997 | 1.001 | 1.000 | 1.003 | 1.011 | 1.019 | 1.007 | 1.002 | 1.003 | 1.015 | 1.031 | 1.008 | 1.014 | 1.014 | 1.007 | 0.999 | 0.999 | 0.999 | 0.998 | 0.998 |

NPs contribution. Due to the reactive load model impacts on nodal demand prices, the real and reactive power absorption is reduced at those buses in which the sensitivity of the objective with respect to the injection of reactive power is positive and vice versa, striving to congestion removal. As regards the market metrics, for fixed loads ( $\varepsilon = 0$ ), the total demand is obviously equal to the base case but the constraints activation causes an higher average nodal demand price, as may be seen from Table 1. For positive values of elasticity, the constraint activation causes a reduction both in the power traded and in the market efficiency. A MCP does no longer exist and each load bus has a different nodal demand price; the average value of nodal demand prices is higher than the average value of nodal generator prices and, hence, the merchandise surplus becomes greater than zero, showing that, due to congestion, a surplus arises for the IGO, along with a loss of efficiency of the market. As elasticity increases all those impacts are damped and, in the limit of an infinite uniform elasticity value, the total demand tends to the base case value, the merchandise surplus and the price standard deviation tend to zero and the nodal demand prices converge to the unit MCP.

#### C. Minimum voltage limit impacts

The impact on prices of the activation of a minimum voltage limit equal to 0.9978 pu at bus 10 are reported in Tab 4. The real NPs are different at each bus. The reactive NPs are positive and the highest reactive NP is that at bus 10, in which the constraint is binding. The system is undergoing a situation of lack of reactive power and the reactive model considered

produces an increase of the nodal demand price to which corresponds a decrease both of real and reactive demand which strive in the direction of congestion removal. The impacts of the variation of elasticity in this case are analogous to those of case B, as may be seen from Table 1.

#### D. Maximum voltage limit impacts

The activation of a maximum voltage limit at bus 10, equal to 0.9770 pu, is considered in this case and its impacts on prices are reported in Table 5. Again no MCP does exist. Reactive NPs are negative at each bus leading to a decrease of the demand prices with respect to the real NP. In this case the network experiences a surplus of reactive power and the reduction of the nodal demand prices produces an increase in real and reactive demand, striving for congestion removal. The average generation prices are higher than the average nodal demand price, causing a negative merchandise surplus, which means that the IGO, at the optimum, instead of collecting a surplus, needs to subsidy the system. The elasticity impacts on the economic metrics are reported in Table 1. The total demand is increased with respect to the base case and tends to the base case value for infinite elasticity. The merchandise surplus and the standard deviation tend to become zero while the nodal demand prices tend to the MCP, as elasticity increases.

#### E. Reactive load modeling impacts

We consider the activation of the same constraint as in case C but with a different load model; each load has a constant reactive power demand equal to the base case, instead of a

Table 5 - Real and reactive nodal prices and nodal demand prices for the lossless case with a maximum voltage limit at bus 10 -  $\varepsilon = 1$  (case D)

| nodal variables | bus   |        |        |        |        |        |        |        |        |        |        |        |        |        |        |       |       |       |       |       |
|-----------------|-------|--------|--------|--------|--------|--------|--------|--------|--------|--------|--------|--------|--------|--------|--------|-------|-------|-------|-------|-------|
|                 | 2     | 3      | 4      | 7      | 8      | 10     | 12     | 14     | 15     | 16     | 17     | 18     | 19     | 20     | 21     | 23    | 24    | 26    | 29    | 30    |
| $D_d$           | 0.215 | 0.024  | 0.076  | 0.231  | 0.313  | 0.062  | 0.115  | 0.063  | 0.083  | 0.037  | 0.101  | 0.033  | 0.100  | 0.023  | 0.180  | 0.032 | 0.087 | 0.035 | 0.024 | 0.105 |
| $\lambda_d^a$   | 1.010 | 1.009  | 1.009  | 1.008  | 1.007  | 1.002  | 1.006  | 1.004  | 1.004  | 1.003  | 1.000  | 1.000  | 0.997  | 0.998  | 1.002  | 1.004 | 1.003 | 1.005 | 1.006 | 1.006 |
| $\lambda_d^r$   | 0.000 | -0.030 | -0.036 | -0.040 | -0.050 | -0.211 | -0.047 | -0.049 | -0.049 | -0.119 | -0.185 | -0.108 | -0.142 | -0.159 | -0.047 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| $v_d$           | 1.010 | 0.994  | 1.001  | 0.989  | 0.957  | 0.929  | 0.975  | 0.992  | 0.989  | 0.942  | 0.881  | 0.969  | 0.946  | 0.947  | 0.972  | 1.004 | 1.003 | 1.005 | 1.006 | 1.006 |

Table 6 - Real and reactive nodal prices and nodal demand prices for the lossless case with a minimum voltage limit at bus 10 and constant reactive power load model -  $\varepsilon = 1$  (case E)

| nodal variables | bus   |       |       |       |       |       |       |       |       |       |       |       |       |       |       |       |       |       |       |       |
|-----------------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|
|                 | 2     | 3     | 4     | 7     | 8     | 10    | 12    | 14    | 15    | 16    | 17    | 18    | 19    | 20    | 21    | 23    | 24    | 26    | 29    | 30    |
| $D_d$           | 0.228 | 0.025 | 0.078 | 0.227 | 0.294 | 0.053 | 0.111 | 0.059 | 0.078 | 0.033 | 0.079 | 0.028 | 0.078 | 0.018 | 0.162 | 0.031 | 0.083 | 0.034 | 0.024 | 0.105 |
| $\lambda_d^a$   | 0.951 | 0.969 | 0.978 | 1.006 | 1.019 | 1.089 | 1.009 | 1.046 | 1.047 | 1.064 | 1.119 | 1.128 | 1.177 | 1.166 | 1.075 | 1.036 | 1.048 | 1.024 | 1.008 | 1.008 |
| $\lambda_d^r$   | 0.000 | 0.729 | 0.883 | 0.973 | 1.211 | 5.159 | 1.150 | 1.183 | 1.199 | 2.889 | 4.520 | 2.620 | 3.456 | 3.888 | 1.140 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| $v_d$           | 0.951 | 0.969 | 0.978 | 1.006 | 1.019 | 1.089 | 1.009 | 1.046 | 1.047 | 1.063 | 1.119 | 1.128 | 1.177 | 1.166 | 1.075 | 1.036 | 1.048 | 1.024 | 1.008 | 1.008 |



constant power factor demand. The impacts on economic metrics and nodal demand prices are reported in Table 1 and 6. The market efficiency is reduced with respect to the constant power factor case, as shown by the reduction of social surplus to 1.337 \$/h. The total demand is reduced too, while the nodal demand prices are increased. The reactive NPs are higher than in the constant power factor case and, for some buses, even greater than the real NPs. In particular the reactive NP is the highest for bus 10, in which the constraint is binding. Due to the independence of the reactive on the real demand, the nodal demand price is not affected by the reactive NPs but is equal to the real NP at each bus. The model adopted leads to a lower amount of power traded at a higher cost. The example shows how the reactive load model may impact the market outcomes and suggests the constant power factor model as more suitable for the OPF studies.

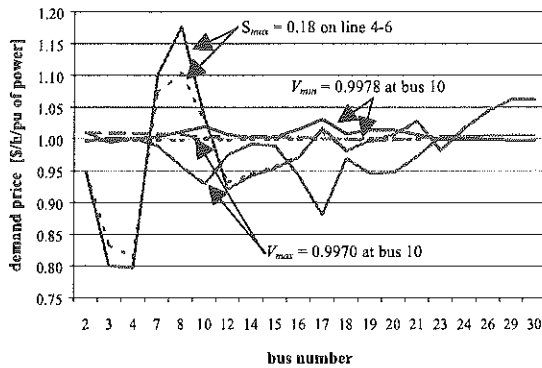


Fig. 3 – Nodal demand price composition and volatility for different constraints

The impacts of the various constraints on the lossless system are summarized in Fig. 3,4 and 5. Fig. 3 shows the nodal demand price (continuous lines) composition in terms of real NPs (dashed lines), for different constraints activation. For a binding maximum line flow limit, the nodal demand prices may be greater or lower than the real NPs; the difference among the two is the reactive NP that may be positive or negative, depending on the bus. For a binding maximum voltage limit, the reactive NPs are always negative and the nodal demand prices are always lower than the real NPs. On the contrary, for a binding minimum voltage limit, the reactive NPs are always positive and, hence, the nodal demand prices are always higher than the real NP. In Fig. 4 are depicted the changes in the merchandise surplus for different constraints and values of uniform elasticity. The absolute value of the merchandise surplus is decreased by an increase of uniform

elasticity and, in the limit to which the load elasticity tends to infinite, merchandise surplus tends to zero. The behavior of average nodal demand price is depicted in Fig. 5, for the different types of constraints, as the uniform elasticity varies. An increase of elasticity may produce and increase or decrease in the average nodal demand price but the variation approaches, in any case, the MCP of the unconstrained case, which is effectively reached in the limit of an infinite elasticity.

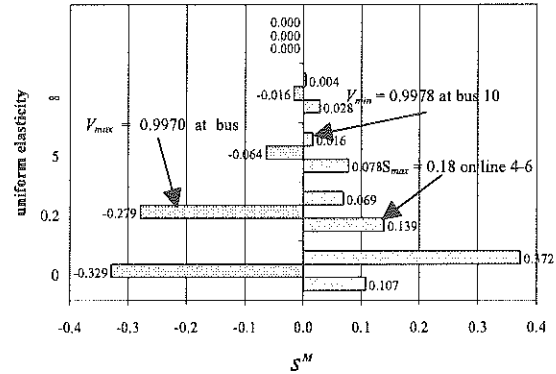


Fig. 4 – Merchandise surplus for different uniform elasticity values

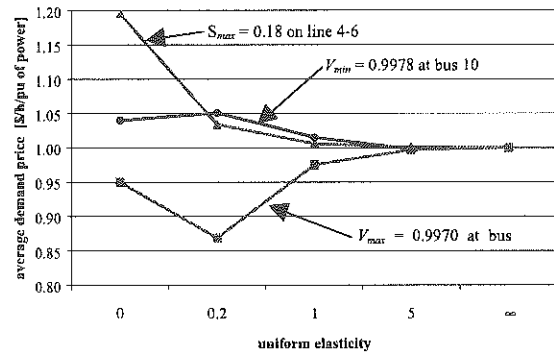


Fig. 5 – Average nodal demand prices for different uniform elasticity values

#### F. Losses impacts

We bring in losses in the base case *A*. The impacts are reported in Table 1 and 7. The effect of losses is analogous to the activation of a constraint; the real NPs are different at each bus and the reactive NPs become positive, causing the nodal demand price to depend also on reactive power demand. The situation, as elasticity varies, is depicted in Fig. 6 in which both the total demand and the percentage losses are represented. For

Table 7 – Real and reactive nodal prices and nodal demand prices for the base case with losses (uniform unity elasticity) power load model -  $\epsilon = 1$  (case *F*)

| nodal variables | bus   |       |       |       |       |       |       |       |       |       |       |       |       |       |       |       |       |       |       |       |
|-----------------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|
|                 | 2     | 3     | 4     | 7     | 8     | 10    | 12    | 14    | 15    | 16    | 17    | 18    | 19    | 20    | 21    | 23    | 24    | 26    | 29    | 30    |
| $D_d$           | 0.223 | 0.024 | 0.076 | 0.227 | 0.296 | 0.058 | 0.112 | 0.061 | 0.082 | 0.035 | 0.089 | 0.031 | 0.092 | 0.022 | 0.174 | 0.032 | 0.087 | 0.034 | 0.024 | 0.104 |
| $\lambda_d^a$   | 0.973 | 0.989 | 0.993 | 1.001 | 1.001 | 1.004 | 0.996 | 1.009 | 1.005 | 1.005 | 1.008 | 1.019 | 1.023 | 1.019 | 1.004 | 0.989 | 1.001 | 1.006 | 1.001 | 1.018 |
| $\lambda_d^r$   | 0.000 | 0.004 | 0.005 | 0.005 | 0.012 | 0.007 | 0.003 | 0.007 | 0.006 | 0.008 | 0.010 | 0.011 | 0.013 | 0.012 | 0.003 | 0.000 | 0.003 | 0.016 | 0.007 | 0.010 |
| $v_d$           | 0.973 | 0.991 | 0.994 | 1.003 | 1.013 | 1.007 | 0.998 | 1.011 | 1.007 | 1.009 | 1.015 | 1.022 | 1.028 | 1.023 | 1.006 | 0.989 | 1.004 | 1.016 | 1.004 | 1.020 |

high values of elasticity, the total demand tends to increase while the losses tend to decrease.

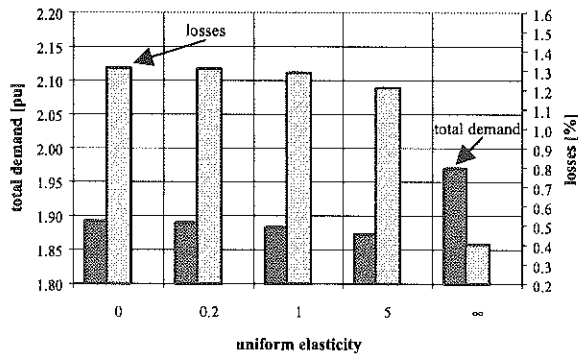


Fig.6 – Total demand and losses for different uniform elasticity values

#### G. The load participation impacts

The load model proposed allows for an evaluation of the major economic impacts of the explicit representation of the participation of price responsive demand in a market based on the pool paradigm. We summarize the general findings that have been derived from the numerical examples and that may be generalized in the light of an extensive set of simulation that have been run.

The demand responsiveness, characterized in terms of elasticity, may play a major role in competitive electricity markets, particularly in the case of congestion occurrence. The impacts of congestion are alleviated in presence of load elasticity and, in the limit of a uniform infinite load elasticity, the impacts tend to be eliminated.

Demand responsiveness has a great impact on prices and price volatility, in terms of lowering the weighted *average price* and narrowing the *standard deviation*. As elasticity increases, the nodal demand prices at each node approach the MCP and in the limit to which the load elasticity tends to infinite, the nodal demand prices at each bus are coincident with that price, for a lossless system. The standard deviation of average nodal demand price is much lower in the case of load responsiveness; it reduces with the increase of elasticity, rising the zero value for infinite elasticity.

The *loss of efficiency* and the *congestion costs*, measured by merchandise surplus, decrease with the elasticity increase. For an infinite elasticity value merchandise surplus is zero, as in a market without network represented.

The consideration of a detailed network model with reactive flows and constraints explicitly modeled permits to point out that, in a lossless system, merchandise surplus may be negative, for certain constraint violations, due to a surplus of reactive power in the network. In such a situation, given a set of offers and bids from generators and customers and the system constraints, the IGO could be forced to subsidize the system in order to balance the load and generators at a point of maximum economic efficiency. If losses are brought in,

merchandise surplus may be reduced by these constraint violations, causing a reduction of the surplus of the IGO.

The nodal demand prices of the loads may be interpreted in terms of summation of the dual variables. Disregarding the activation of limits on real demand, the nodal demand price components are real and reactive NPs. Hence, the reactive load model impacts the nodal prices and the resulting demand levels. The explicit representation of losses and system constraints results in non homogeneous real and reactive NPs. Those prices impact nodal demand prices and, consequently, the level of real and reactive demand in the system and provide appropriate signals to the market. If a reactive power limit is reached the reactive NP is different from zero and nodal demand price is affected by it, proportionally to its power factor. If the network has a lack of reactive power, the reactive NP is positive and it contributes to increase the bid price, reducing the real power demand and, proportionally, also the reactive power demand. If the network has a surplus of reactive power, the reactive NP is negative and contributes to decrease the bid price, increasing the real power demand and, proportionally, also the reactive power demand.

#### V. Conclusion

We proposed a general model of price-responsive load, both with real and reactive demand explicitly considered, in which the responsiveness is expressed as a function of load elasticity. The model was implemented in the application of the nonlinear OPF to assess the impacts of demand participation in competitive markets. These impacts become particularly marked in congestion relief actions.

An increase in the demand elasticity decreases the congestion impacts in many respects: the loss of efficiency and the congestion costs, as measured by merchandise surplus, are lowered by an increase in elasticity, the average prices and the volatility of nodal demand prices are lower in presence of higher load responsiveness.

In lossy or congested systems, the nodal demand prices are dependent both on the real and reactive NPs due to the reactive model proposed. The price signals derived strive in the direction of alleviating congestion; the nodal demand price are driven higher or lower by the reactive NP as to decrease or increase the real demand, in the direction of congestion removal.

Further investigation are needed for assessing the impacts of non uniform nodal demand responsiveness and to design a coherent set of incentives for promoting load elasticity to contribute to congestion relief and to the lowering of its costs.

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## Discussions on Session III: MARKETS Part 1

**Chairman (P. Sauer):** We now have time for discussion, I'd like to ask three presenters to return.

**G. Gross (University of Illinois):** Let me ask a question for Professor Daalder. In terms of the reactive power and ancillary service, I'm a little bit lost in terms of the model because my understanding is that this market would be very difficult to implement. In order to have a market, you have to have it locally as you said. Yet, it is unlikely that we're going to have multiple generators at the same time at the same bus to provide the service. So perhaps you can address this issue and how you see that is resolved.

**J. Daalder:** It's quite right. I've already indicated the possible problems in generating such a market. One of the possibilities is that the reactive power markets should include more than just the generators. Capacity banks, valves, etc., not in the least power producing companies could be also active in this market. It is quite clear that this is different from the active power market because there are restrictions as far as the reactive power concerned. On the other hand, if you look at the overall efficiency, you're considering reactive power to some extent like active power because you have to pay for it. So far there hasn't been a cost, you don't know or realize what it really cost. In the simple model, we're saying that reactive power, if the IPP is paid for its losses, and is paid for its scheduling, it shows that the overall efficiency of the system is increasing, I think that it is worthwhile.

**G. Gross:** Let me just comment that the ancillary service as seen by FERC, the Federal Energy Regulatory Commission, is only from generators. So any reactive power coming from the capacity bank would not be considered an ancillary service. It would be considered part of the network transmission service provided by transmission provider.

**J. Daalder:** You're quite right. That's the reason why I show it. The model so far is based on that aspect. On the other hand, we should realize that, at least in Sweden, capacity banks / vars is a responsibility mostly of the regional networks and the lower voltage networks, because there are restrictions on the grid sides. The ISO always specify what kind of limits it has on its buses and these are mandatory. But the costs are involved there, and I think that modeling reactive power makes it much more clear where his costs are generated, and it is not unreasonable that it should be part of the picture. So this is going further than what was considered as ancillary services. We're working now on extending the model

including static sources for active power.

**C. Vournas (National Technical University of Athens):** I would like to add a comment to this discussion. I have a feeling that there is something fundamentally wrong in trying to model the reactive power as a product. The reactive power is not a product. What you get from the reactive power is the support to transmit active power. So I would speak about the market of the reactive support of the system, and then try to figure out what is the support that each generator is providing for power transfer, subtracting the reactive power the generator has to produce in order to transmit its own active power. So along this line, it would be much easier to discuss the market for reactive support. MVars are not the unit with which to pay for reactive power. The reactive support should be paid according to the difference it makes in active power to be transmitted in a certain case. This is another way of putting things. We may need another paper for that.

**J. Daalder:** Well, I'm not quite sure. If I'm buying a radio, I expect some properties of this radio. The same is true for the product of the active power. This will be delivered with certain qualities of voltage or frequency. In that case, I believe that the reactive power is directly coupled to the voltage and is part of the product.

**F. Wu (Hong Kong University):** I have a question for Mr. Bompard. What do you envision the information the consumers have to reveal? The preferred loading point and the elasticity? How frequently do they have to reveal? Or, can they modify their preferred schedule and the elasticity?

**E. Bompard:** Well, of course, I didn't say that but we're thinking the day-ahead market, so this information is offered, let's say one hour the day after, for instance. In any case, the loads have to reveal a bid curve to submit to the pool of bid curves. They can define this bid curve as a reference point and the elasticity. This is not a great difference. What is there to reveal is only their bid, nothing more. I mean it is the same as the four types of generators. What they submit to the pool is just an offer. In the same case in the same way, the loads submit just the bid. This can be defined in this way. But I think they are not going to reveal more than they usually should do.

**L. Vargas (University of Chile):** This is a question for T. Overbye. If I understand it correctly, you're trying to obtain is the equivalent of the equilibrium of the system. You gave a very nice example of playing with the rock,

the scissors, paper. So if you always play the same way, you will lose. My question is as followed. Does every player know what the stationary point is? Would that mean they would play the same way in the bidding?

**J. Overbye:** Some systems have a static Nash equilibrium. If I bid what I should to get to that equilibrium, you can bid whatever you want, but your best response is to bid, so that you will be at the Nash equilibrium. Other system, including a two-bus example, with the line constraint does not have a Nash equilibrium in a static sense. When you run out the dynamics, you get limit cycle behavior, with oscillations back and forth, there is no point that it will converge in where I can do this and you should do something. The only way we can get to the kind of an equilibrium is for one or both of us to use a mixed strategy. What happen is what we're doing is that we're gaming the line constraint. Sometimes the line is constrained, sometimes it is not constrained. But if you always want it to be perhaps unconstrained, I always win. So you really have to do a mixed strategy, at least one of the participants does.

**Chairman:** I have a question for all three of you. I guess the word market power hasn't come up. Could each of you address the issues of market power in your respective ideas? How would the effect be if someone has unlimited power? Not electric power, unlimited power to charge whatever she wants.

**J. Overbye:** I can address them. I'm sure the others can, too. Market power is inherent in what I'm talking about. The reason why you would not bid your marginal cost is because you got some market power. You can increase the prices. That's what we're looking beyond the marginal cost. In the work that we're doing, I included load responsiveness. We have price dependent load there, otherwise you would just get into a situation for profit increases without one player or a couple players have the ability to raise price as high as they want. One way you can get around that is the price cap. The other way you can get around it is saying the load is dependent upon price, so market power is inherent in what we're doing. What we're trying to look at is whether there is a potential market for market power? Primarily it would be in the sense that perhaps you might be looking as the regulators to see if these two utilities merged, can they increase price kind of as much as they want?

**E. Bompard:** I agree perfectly with Professor Overbye. I guess that the market power may be reduced with a lot of price dependent load. What happened in California was that the loads are more or less fixed. The producer had a great deal of possibilities to exercise the market power. They have to reduce the market power with price cap.

**L. Fink:** I would like to ask Professor Daalder. What would be the effect on his analysis, if considering requirements for reactive reserve on generators for emergency support of system voltage?

**J. Daalder:** Well, of course you have certain requirements in case of disturbances. I think that probably has to be treated in the other way, which could be that if you're active in this part of the market. Another type of contract could be made with the ISO, when he is asking for emergency. I think it is a little bit dependent upon the availability of reactive power in the market. The tendency is, of course, to maximize, as an IPP, active power, not reactive power.

**S. Meliopoulos (Georgia Tech):** I would like to comment on the price elasticity. That is a very fine work. On the other hand, traditionally the price elasticity has some time delays. We have seen that in California, where the load was down considerably when the price went very high. But that took some time, and some news reports, and so on. A lot of people sought after the facts, what the price was, and they responded to that. The question is, is it possible to incorporate our model of price elasticity model, where there is some delay on this model? There is going to be some time delays in responding to the price sophistication. Is it possible to build such a model?

**E. Bompard:** I guess it is possible but probably there is a misunderstanding in what was the goal of our model, and probably it is connected to the question that Professor Wu posed before. Actually you're telling me that the customers need some time to react to price signals. This is true. This is true particularly if you fix the demand foreseen for each hour the day after. These bids are given for each hour of the day after each day. So the response will be very quick. I don't know if I answer your question. I mean if I was given the last clock in the long run, and the last clock can change to the price, new to the price signal, and this is true. But in this case, we can think also, loads do not bid on the market. In our model, we consider just loads that bid on the market for each hour of each day. So the elasticity can change from day to day, because they submit their bid to the market.

**J. Overbye:** One of the challenges we have in the model on electric power market is, it's taking into account the longer term dynamics of the system. In that, the generators are not just playing a static optimization as I presented here. They're playing the same game repeatedly over time. If you have market power as Pete talked about, it could raise the price. Would you do that? Well, as a planned market, you have to look at many issues that go beyond what you model. If I charge infinity for electricity, will I get paid? Well, if you will get paid an infinite amount, then just charge for an hour, then you can sell the company and retire. But you probably won't want to do that because there

is a consequence. You know you won't get paid, the customers in a longer term might switch to different fuel and things like that.

**G. Gross:** I want to comment on the question of Sakis' s. We're all looking forward to time when we're going to have real time metering. So we're not looking at something that is unrealistic. Eventually we're driving there, so you have the information, and the load can react to the price that you get. So it is not in everywhere unrealistic to look at this model. In fact, this is a big issue, I think, for the entire group of how soon we can get to real time metering, so the loads can react. You're correct in what you said about California. But in California, its actual question of not having that information available, because the price was fixed no matter what. So there was absolutely no incentive for anybody to turn down the load, because the price we're paying was 7.4 cents per kilowatt/hour. Although the real price could be a dollar per kilowatt/hour so there is no incentive. One more comment about market power is that, basically in a network, even a very small generator can have market power. The issue is, as Tom pointed out in the last comment, who wants to exercise the market power? In order to answer that question, we also have to know what contracts are in place because if a long-term contract is in place, the idea of exercising market power is not making any kind of sense.

**J. Overbye:** I agree with you on market power. On the real time monitoring, not all of us are looking for having real time pricing in our houses. I think there will be a strong market of consumers who just don't want to bother with it. You know the load aggregator might be subjected to that and they offer product for consumers, some might want to look at the price to see when to turn on the TV or not, and others of us would not.

**S. Meliopoulos:** Well, all of these comments are very good but I would like to make a point. Big customers and big loads can play a real time optimization approach in the case where they do have the information of pricing and so on. We need to talk about a realistic model. I don't see we can expect customers to respond to real time pricing. There are going to be some responses, or be affected by differential, and so on. Until we get to a point where some experiment that would determine the response to prices, I don't see we will ever have a realistic model price elasticity in that domain.

# Pricing System Security in Electricity Markets

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**Abstract**—This paper proposes and describes in detail two distinct and novel methodologies to try to address the issue of a proper representation of system security in the operation of decentralized and hybrid electricity markets, so that adequate price signals can be given to all market participants. Both methodologies are based on the use of voltage stability theory to better account for system security. For each of the presented techniques, a methodology to determine “nodal” marginal prices is proposed and described in detail. A 6-bus system with both supply and demand-side bidding is described and used to test and compare the proposed techniques.

**Keywords**—Electricity markets, locational marginal prices (LMP), security, available transfer capability (ATC).

## I. INTRODUCTION

THE current rush to deregulate electricity markets throughout the world has led to the proposal of several market structures that could be categorized into three main groups, namely, pool or centralized markets (e.g., the “old” U.K. market, Chile, and PJM), standard auction or decentralized markets (e.g., Spain and the former California markets), and spot pricing or hybrid markets (e.g., New Zealand, Ontario, and the current U.K. and New England markets) [1], [2], [3].

### A. Centralized or Pool Markets

Centralized markets can be basically viewed as unit commitment problems where a “central” broker/operator takes care of “dispatching” the market participants based on their bids, while accounting somewhat for the transmission system and network security. Because of the complexity of the problem, which is in itself a disadvantage since it is not “transparent” to the market participants, the network is usually modeled using only a dc power flow model. Limits on the transmission line power flows used to try to represent system security tend to be somewhat arbitrary, as these limits are predetermined based on off-line studies that do not necessarily correspond to the actual system operating conditions.

This model has the perceived advantage of producing an “optimal” solution, taking into consideration temporal restrictions such as minimum up and down times, but there is no guarantee that a unique solution, or even a solution may be found for this problem [4]. The dc model used to represent the network leads to solutions that most likely do not reflect the actual security level of the system, es-

pecially if conservatively low power flow limits are used in the transmission system, which is usually the case. The latter might lead to high prices as a result of unrealistic constraints becoming active.

Another disadvantage of this methodology is that it forces the unbundling of ancillary services, such as reactive power, requiring iterative techniques to obtain adequate solutions for energy and ancillary service markets [2].

Although some of these problems could be resolved in theory by including the ac power flow equations, this is not considered practical due to the complexity of the problem. Thus, this problem, together with the “centralized” nature of this type of market, gives participants a sense of lack of “transparency” in the handling of transactions. This has led to the use of other market architectures in the implementation of most new electricity markets. For all of these reasons, the issue of proper consideration and pricing of security in this type of market structure is not pursued further in this paper.

### B. Decentralized or Simple Auction Markets

Decentralized markets are basically “transparent” markets run by a central broker where only the participants’ bids are used to determine a market clearing price using a simple auction mechanism, without considering system constraints. The results of this auction are then passed on to a market operator who may approve, modify and/or reject the transactions, depending on the market rules.

In these types of markets, ancillary services are basically unbundled and determined in sequential markets (e.g., reactive power and reserve markets). This approach has the problem of not considering the actual system conditions during the bidding process, particularly system security, which may lead to inadequate price signals that would make it difficult for the participants to develop appropriate bidding strategies.

The present paper proposes a methodology to properly introduce system security in this type of market structure, so that prices somewhat reflect the “level” of security of the real system. The proposed methodology is based on an iterative computation of the Available Transfer Capability (ATC) and the “redispatch” of generators and loads by determining the impact of the different transactions through sensitivity analysis. The ATC and required sensitivities are all determined based on voltage stability criteria. These

sensitivities are also used to determine a marginal price for each of the market participants, so that their effect on system security is accounted for in the final prices.

### C. Hybrid or OPF-based Markets

Hybrid markets are based on classical spot pricing theory [1], [2], and allow for an adequate bundling of energy and ancillary service markets, so that proper price signals can be given to all market participants from a global system operation perspective through the use of locational or “nodal” marginal prices [5].

These markets can be viewed basically as Optimal Power Flow (OPF) “security constrained” problems, with the objective of maximizing social welfare as opposed to minimizing costs, i.e., the objective is to minimize the differences between supply and demand bids. The unit commitment problem is assumed to be resolved by “preprocessing” of the bids; for example, temporal restrictions such as ramp rates may be included as limits on the power bids (e.g., [6]).

An advantage of these types of markets is that there is extensive experience with the use of OPF in power system operation, with mature solution methodologies that have been proven to work in practice and that can be readily applied to electricity markets. For these reasons, many electricity markets are being implemented or modified to operate based on these techniques. A problem with these types of markets, as with the classical OPF problem, is that system security is somewhat arbitrarily represented through limits in power transfers that most likely do not reflect the actual security levels associated with a given operating condition, thus yielding inappropriate price signals [7].

In this paper, a technique to better account for system security than just using somewhat “arbitrary” limits on transmission line power flows is proposed for hybrid markets. The proposed methodology is based on a voltage stability constrained OPF proposed in [8]. Although in this method it is not possible to directly represent the (N-1) contingency criteria used in the computation of the ATC, the effects of contingencies can be indirectly represented through an “adequate” choice of the value of the stability margin in the optimization procedure, as explained below.

### D. Content

The methodologies presented in this paper try to address the issue of a proper representation of system security in the operation of a decentralized and a hybrid market, so that adequate price signals can be given to all market participants. Both methodologies are based on the use of voltage stability theory to better account for system security [9]; although this approach does not fully account for the actual dynamical security of the system, it does represent system security in a much more accurate way than the simple use of predetermined limits on power flows.

The paper is thus structured as follows: Section II de-

scribes the introduction of voltage stability constraints in an OPF-based electricity market, including a discussion on the effect of these constraints on the marginal prices. Section IV comments on the results obtained for a 6 bus test system with demand-side bidding, concentrating especially in comparing the different proposed methodologies. Finally, Section V summarizes the main ideas and results obtained in this paper, as well as the advantages and disadvantages of the proposed techniques.

## II. SIMPLE AUCTION SYSTEM WITH REDISPATCH

The redispatch and pricing methodology proposed here is basically an implementation of a simple auction system where ATC computations and sensitivity analyses, based on voltage stability criteria, are carried out for the given bidding conditions. This method is based on sensitivity formulas developed for the stability limit conditions defined by the ATC; the redispatch costs are then distributed among the market participants based on the sensitivity factors obtained from these formulas.

This section concentrates on describing the techniques used for the ATC and sensitivity calculations, and their use in the proposed redispatch and security pricing algorithm.

### A. ATC Calculations and Sensitivity Formulas

The ATC, as defined by NERC, is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses [10]. Thus, mathematically it is defined as

$$ATC = TTC - ETC - TRM \quad (1)$$

where

$$TTC = \min(P_{\max I_{lim}}, P_{\max V_{lim}}, P_{\max S_{lim}})$$

represents the Total Transfer Capability, i.e., the maximum power that the system can deliver given the security constraints defined by thermal limits ( $I_{lim}$ ), voltage limits ( $V_{lim}$ ) and stability limits ( $S_{lim}$ ), and an (N-1) contingency criterion (worst single contingency of the transmission system). ETC stands for the Existing Transmission Commitments, and TRM corresponds to the Transmission Reliability Margin, which includes a Capacity Benefit Margin (CBM) and is meant to account for uncertainties in system operation.

From the ATC definition (1), it is clear that its value changes with the system operating conditions, and hence has to be computed for every bidding condition. However, in most of the current implementations of electricity markets, the ATC is determined in off-line studies and represented in the bidding process as rather conservative limits on the power flowing through the transmission lines or main transmission “corridors”. This is obviously unrealistic and could easily lead to either fictitious congestion problems,



The problem in the computation of the ATC is the actual determination of the stability limits, which require costly time domain simulations. Hence, in the present paper, the stability limits are approximately represented using voltage stability margins, which can be readily and quickly computed, giving a good idea of the “relative” stability of the network [9]. In this case, a continuation power flow approach is used to determine the maximum system loading or TTC, as defined in (1) [11].

Since voltage stability criteria are used to determine the ATC value, one can also readily determine the sensitivities of the ATC with respect to various systems parameters, especially with respect to the participants’ bids. The required sensitivity formulas can be obtained from the definition of the TTC and the use of basic voltage stability concepts [9].

Thus, consider that the system can be represented in steady state with the following set of nonlinear equations:

$$f(x, \lambda, p) = 0 \quad (2)$$

where  $x \in \mathbb{R}^n$  stands for the state and algebraic system variables, such as bus voltage magnitudes and angles;  $\lambda \in \mathbb{R}$  is the “bifurcation” or loading parameter used to represent the system loading level, as the load powers are modeled as  $P_L = P_{L_0} + \lambda P_D$ , with  $P_{L_0}$  representing the load power levels at the initial loading conditions and  $P_D$  corresponding to the demand power bids (all loads are assumed to have constant power factors); and  $p \in \mathbb{R}^m$  corresponds to “controllable” system parameters, such as the supply and demand power bids  $P_S$  and  $P_D$ , respectively. In this analysis, generator powers are modeled as  $P_G = P_{G_0} + (\lambda + k_G)P_S$ , where  $P_{G_0}$  is the initial generation loading conditions and  $k_G$  is a variable used to represent a distributed slack bus. Equations (2) typically correspond to a set of “modified” power flow equations, which basically result from modeling system controls and limits in greater detail than in the typical power flow equations.

The voltage stability limits for system (2) are basically associated with saddle-node and limit-induced bifurcations of the corresponding set of nonlinear equations [9]; at these bifurcation points, the system collapses. Thermal and voltage limits, on the other hand, can be treated mathematically, for the purpose of sensitivity analyses, in a similar way as limit-induced bifurcations, although the system does not collapse when these limits are reached. Hence, for (2), the ATC can then be defined as

$$\text{ATC} = \lambda_c \quad (3)$$

if the TRM is neglected, and where  $\lambda_c$  is the “critical” (“maximum”) loading level at which the system is at a limit condition, as per definition (1).

In this paper, all ATC and required sensitivity values are computed based on the results generated by UWPFLOW [12], which is a continuation power flow program capable of representing various power system elements using “detailed” steady state models.

### A.1 Saddle-Node Bifurcations

Saddle-node bifurcations (SNB) are characterized by a pair of equilibrium points coalescing and disappearing as the bifurcation parameter  $\lambda$  “slowly” changes. Mathematically, the SNB point is an equilibrium point  $(x_c, \lambda_c, p_c)$  with a singular Jacobian  $D_x f|_c$  and associated unique right and left “singular” eigenvectors  $v$  and  $w$ , respectively, i.e.,  $D_x f|_c v = D_x^T f|_c w = 0$ .

By taking the derivatives of (2), one has at the SNB point that

$$\begin{aligned} D_x f|_c dx + D_\lambda f|_c d\lambda + D_p f|_c dp &= 0 \\ \Rightarrow w^T D_x f|_c dx + w^T D_\lambda f|_c d\lambda + w^T D_p f|_c dp &= 0 \end{aligned}$$

Hence, from these equations and as proposed in [13], one has that the sensitivities of the system loading  $\lambda$  with respect to changes in the parameters  $p$  at the SNB point can be determined by using

$$\left. \frac{d\lambda}{dp} \right|_c = -\frac{1}{w^T D_\lambda f|_c} w^T D_p f|_c \quad (4)$$

### A.2 Limits

Limit-induced bifurcations (LIB) are equilibrium points where a system control limit is reached, which in some cases may lead to a system collapse characterized by a pair equilibrium points coalescing and disappearing for slow changes of the bifurcation parameter  $\lambda$ . At a LIB, as opposed to a SNB, the system Jacobian is not singular at the bifurcation point  $(x_c, \lambda_c, p_c)$ ; hence, equation (4) does not apply at this point.

In general, a system reaching a limit at an equilibrium point  $(x_c, \lambda_c, p_c)$  can be characterized by two different sets of equations, i.e.,

$$\begin{aligned} f_1(x_c, \lambda_c, p_c) &= 0 \\ f_2(x_c, \lambda_c, p_c) &= 0 \end{aligned} \quad (5)$$

where the first set  $f_1(\cdot)$  corresponds to the “original” system equations, whereas the second set  $f_2(\cdot)$  corresponds to a modified set of equations where the limit is active. For example, when a reactive power generator limit is reached at a bus  $i$ , a generator voltage control equation, say  $V_i - V_{i_c} = 0$ , may be replaced by  $Q_{G_i} - Q_{G_{i,m}} = 0$  at the limit condition. Hence, taking the derivatives of (5) at the equilibrium point where the limit becomes active,

$$\begin{aligned} D_x f_1|_c dx + D_\lambda f_1|_c d\lambda + D_p f_1|_c dp &= 0 \\ D_x f_2|_c dx + D_\lambda f_2|_c d\lambda + D_p f_2|_c dp &= 0 \end{aligned}$$

Eliminating  $dx$  from these equations, leads to

$$\left. \frac{d\lambda}{dp} \right|_c = \frac{1}{\mu^T \mu} \mu^T (D_x f_2|_c D_x f_1|_c^{-1} D_p f_1|_c - D_p f_2|_c) \quad (6)$$

where

$$\mu = D_\lambda f_2|_c - D_x f_2|_c D_x f_1|_c^{-1} D_\lambda f_1|_c$$

Observe that the sensitivity formula (6) applies to any limit condition, independent of whether it corresponds to

a LIB or a thermal or voltage limit. Hence, this equation together with (4) are used to determine the sensitivity of the ATC with respect to the system parameters  $p$ , which for the purpose of this paper correspond to the supply and demand bids  $P_S$  and  $P_D$ , respectively.

### B. Redispatch and Security Pricing Algorithm

The redispatch technique proposed in this paper follows similar general criteria as the one currently used in the New England electricity market [14], where redispatch is used to address the issue of a simple auction mechanism, which neglects system losses, yielding a market clearing condition that violates certain congestion criteria, as defined by power flow limits on the transmission system. The costs resulting from dispatching a more expensive unit than the market clearing price ( $MCP$ ) to solve the congestion problem are then “distributed” among the different participants. The main improvements of the technique proposed here with respect to known methodologies are:

- The ATC is computed “on-line”, i.e., taking into consideration the actual system conditions, as opposed to using power flow limits determined off-line that do not necessarily represent the system security level.
- The congestion costs are distributed among the market participants based on the actual impact that each one of them has on the ATC value.

The suggested redispatch technique to address the problem of market clearing conditions that do not meet the actual ATC requirements, as defined in the previous section, is summarized in the flow-diagram shown in Fig. 1. This methodology determines the transaction costs for the different market participants as follows:

#### B.1 Step 1

Using a simple auction mechanism, the  $MCP$  and associated total transaction power level  $T$  are determined, together with the load and generator power levels that clear the market, namely,  $P_D$  and  $P_S$  and for all loads and generators, respectively. The values of  $P_D$  and  $P_S$  are used in the determination of the ATC, as these define the load and generator direction used for the computation of  $\lambda_c$  in UWPFLOW [12].

#### B.2 Step 2

If the ATC is violated, i.e., if  $\lambda_c < T$ , the impact of each possible system transaction is determined using (4) or (6), depending on the limiting factor that defines the ATC. Thus, the generator  $i$  with the most positive impact on the ATC that has not been fully dispatched in the bidding process, and the generator  $j$  dispatched in step 1 with the most negative or least positive impact in the ATC are chosen for rescheduling. Thus, the corresponding increase and decrease in generation is defined as

$$\Delta P_{S_i}^{(k)} = -\Delta P_{S_j}^{(k)} = \Delta P_S^{(k)}$$

where  $k$  is the number of iteration in the redispatch process, and  $\Delta P_S^{(k)}$  is chosen depending on the value that one wants

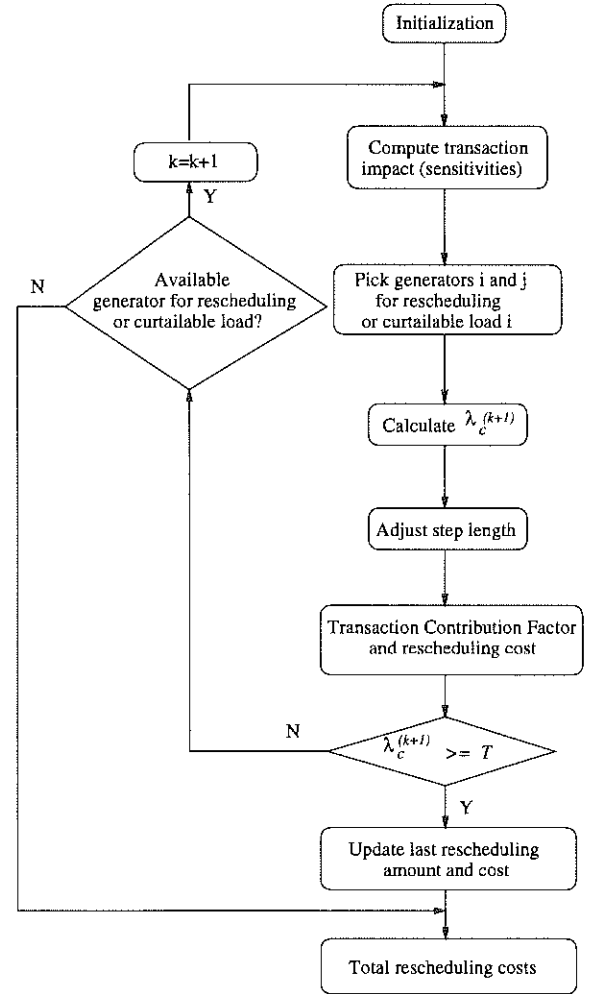


Fig. 1. Redispatch technique for a simple auction system. The ATC at each iteration is represented by  $\lambda_c^{(k+1)}$ , whereas  $T$  represents the transaction level that clears the market.

for the ATC, since the new value of the ATC may be approximated by

$$\lambda_c^{(k+1)} \approx \lambda_c^{(k)} + \left. \frac{d\lambda}{dP_{S_i}} \right|_c^{(k)} \Delta P_{S_i}^{(k)} + \left. \frac{d\lambda}{dP_{S_j}} \right|_c^{(k)} \Delta P_{S_j}^{(k)} \quad (7)$$

It is assumed here that  $d\lambda/dP_{S_i}|_c^{(k)} > d\lambda/dP_{S_j}|_c^{(k)}$ , otherwise no ATC improvements can be attained by redispatching generation.

Since the whole process is based on a linearization, one cannot make large changes in generated power, otherwise this might have a large effect on the actual ATC value, which changes nonlinearly as the parameters change; hence the need for an iterative process. The amount of generation chosen for redispatch  $\Delta P_S^{(k)}$  may be readjusted when determining the actual value of  $\lambda_c^{(k+1)}$  using the full nonlinear system, as explained below.

Observe that system losses are not considered here, as these are just assigned to a “slack” bus. This basically

means that other market mechanisms are used to account for losses in the process, which is typically the case in decentralized market structures.

Only if there are no adequate generators available for redispatch, is the load considered for curtailment. This approach is to be expected when the load is inelastic, as these types of loads require that the forecasted load be dispatched, given the high “costs” of load curtailment. In the case of demand-side bidding, however, the load could be considered for redispatching in the same way as the generators, i.e., the load with the most negative impact on the ATC, say  $i$ , may be reduced by an amount that has a “significant” impact on the ATC value, as per approximation

$$\lambda_c^{(k+1)} \approx \lambda_c^{(k)} - \left. \frac{d\lambda}{dP_{D_i}} \right|_c^{(k)} \Delta P_{D_i}^{(k)} \quad (8)$$

This equation can be used for rescheduling inelastic loads as well. In this case, there is no security cost for load curtailment, since one assumes that the loads are intrinsically running a risk of not being dispatched by participating in the market. However, this means that overall system revenues are lost, as loads that could be served by redispatching available generation would not be dispatched, even if these loads are willing to pay the higher costs of rescheduling generated by the proposed market process. Hence, the load redispatch option, whether the loads are inelastic or not, is only considered if no generation bids are available to solve the ATC violation. Observe that in this case, the transaction level  $T$  is affected by the load reduction; thus,

$$T^{(k+1)} = T^{(k)} - \Delta P_{D_i}^{(k)}$$

This is not the case for generation redispatch; in this case,  $T^{(k+1)} = T^{(k)}$ .

### B.3 Step 3

The step changes in generation or load are readjusted by computing the actual value of  $\lambda_c^{(k+1)}$  and comparing it to the approximated value computed using (7) or (8). If the difference is greater than a chosen tolerance, the previous step and this one are repeated with smaller changes in the supply and demand until the desired tolerance is met.

### B.4 Step 4

The redispatching costs for the given iteration  $k$  are then determined based on a Transaction Contribution Factor (TCF) as defined by

$$TCF_i^{(k)} = \frac{d\lambda/dp_i|_c^{(k)} p_i^{(k)}}{\sum_j d\lambda/dp_j|_c^{(k)} p_j^{(k)}} \quad (9)$$

where  $i$  stands for the bus number, and  $p_i^{(k)}$  corresponds to the value of the corresponding parameter, i.e., the value of  $P_{S_i}^{(k)}$  or  $P_{D_i}^{(k)}$ . Only buses with negative impact on the ATC, i.e., buses with  $d\lambda/dp_i|_c^{(k)} < 0$ , are considered in this computation; buses with positive impact are given a zero  $TCF$  value, so that market participants that do not create

the security problem are not charged for the cost of keeping the system secure. The parameter values  $p_i^{(k)}$  are included in this “normalization” process to account for the “size” of the corresponding transactions in the security cost.

The total generator rescheduling security cost of the  $k^{\text{th}}$  iteration may be defined as

$$SC_k = (C_{S_i} - MCP) \Delta P_{S_i}^{(k)} \quad (10)$$

where  $i$  is the generator chosen in Step 2, with a marginal cost or bid  $C_{S_i}$ , and  $MCP$  is the market clearing price obtained from the simple bidding process in Step 1. In the case of inelastic loads, one can argue that there should be a cost associated with curtailing the load that should be considered as part of the cost of keeping the system secure; thus, one would have in this case that

$$SC_k = A_{D_i} \Delta P_{D_i}^{(k)} \quad (11)$$

where  $A_{D_i}$  is the “cost” of curtailing the load at the chosen bus  $i$ .

### B.5 Step 5

If the ATC requirements are met, i.e., if  $\lambda_c^{(k+1)} < T^{(k+1)}$ , then the iterative process stops, say at  $k = m$ . At this point, the final generator or load reschedules are adjusted based on (7) or (8), respectively, so that the ATC and final transaction level are the same, i.e.,  $\lambda_c^{(m+1)} \approx T^{(m)}$ . Thus,

$$\Delta P_{S_i}^{(m)} = -\Delta P_{S_j}^{(m)} = \frac{T^{(m)} - \lambda_c^{(m)}}{d\lambda/dP_{S_i}|_c^{(m)} - d\lambda/dP_{S_j}|_c^{(m)}}$$

or

$$\Delta P_{D_i}^{(m)} = \frac{T^{(m)} - \lambda_c^{(m)}}{d\lambda/dP_{D_i}|_c^{(m)}}$$

### B.6 Step 6

The final transaction levels and marginal costs for each  $i$  node are readily determined as follows:

• Generators:

$$P_{S_i} = P_{S_i}^{(0)} + \sum_{k=1}^m \Delta P_{S_i}^{(k)} \quad (12)$$

$$\rho_{S_i} = MCP - \frac{1}{P_{S_i}} \sum_{k=1}^m TCF_i^{(k)} SC_k$$

• Loads

$$P_{D_i} = P_{D_i}^{(0)} - \sum_{k=1}^m \Delta P_{D_i}^{(k)}$$

$$\rho_{D_i} = MCP + \frac{1}{P_{D_i}} \sum_{k=1}^m TCF_i^{(k)} SC_k$$

### B.7 Observations

It is important to highlight the fact that the proposed technique to compute “nodal” marginal prices assumes that all the costs of redispatching are fully distributed among the market participants, as is the case of the current New England electricity markets [14]. Hence, since a “zero sum” approach is used in this case, there are no “leftovers” to be used by the ISO for possible upgrades of the transmission system. Furthermore, costs associated with losses and reactive power dispatch, as well as reserves for frequency control, are assumed to be resolved in other independent auction markets or by other market mechanisms, which may in turn yield system operating conditions that could have a significant effect on the marginal costs generated by each one of the different markets. Although the latter might be resolved by using other iterative processes, somewhat similar to the one proposed here for the integration of the ATC into the auction system, this is certainly a disadvantage of these types of markets.

Hybrid markets, on the other hand, produce solutions that account for several of the market costs through an “integrated” solution approach, thus resolving most of these problems. However, these market structures present several other disadvantages associated with a “black box” approach, such as lack of “transparency” and convergence difficulties, as discussed in the next section.

### III. SPOT PRICE OF SECURITY

Hybrid market structures are based on the determination of a spot price of electricity obtained from an OPF solution and its associated Lagrangian multipliers [1], [2], [4]. This technique basically consists on solving the following OPF problem [5]:

$$\text{Min.} \quad C_S^T P_S - C_D^T P_D \quad (13)$$

$$\text{s.t.} \quad f(\delta, V, Q_G, P_S, P_D) = 0 \quad (\text{PF eqs.})$$

$$0 \leq P_S \leq P_{S \max} \quad (\text{supply bid blocks})$$

$$0 \leq P_D \leq P_{D \max} \quad (\text{demand bid blocks})$$

$$|P_{ij}(\delta, V)| \leq P_{ij \max} \quad (\text{“security” limits})$$

$$Q_{G \min} \leq Q_G \leq Q_{G \max} \quad (\text{gen. Q limits})$$

$$V_{\min} \leq V \leq V_{\max} \quad (\text{bus V limits})$$

where  $C_S$  and  $C_D$  are vectors of supply and demand bids in \$/MWh, respectively;  $Q_G$  stands for the generator reactive powers;  $V$  and  $\delta$  represent the bus phasor voltages; and  $P_{ij}$  represent the powers flowing through the lines, which are typically used to “indirectly” represent system security.  $P_S$  and  $P_D$  are the vectors of supply and demand bids of power in MW, provided in blocks of  $P_{S \max}$  and  $P_{D \max}$ ,

and are associated with generator and load powers, since  $P_G = P_{G_0} + P_S$ , and  $P_L = P_{L_0} + P_D$ , where  $P_{G_0}$  and  $P_{L_0}$  basically define the initial system operating conditions (loads are assumed to have constant power factors).

The OPF problem (13) can be transformed into the following optimization problem based on the Lagrangian that results from a logarithmic barrier Interior Point approach:

$$\begin{aligned} \text{Min. } \mathcal{L} = & C_S^T P_S - C_D^T P_D \\ & - \rho^T f(\delta, V, Q_G, P_S, P_D) \\ & - \mu_{P_{S \max}}^T (P_{S \max} - P_S - s_{P_{S \max}}) \\ & - \mu_{P_{D \max}}^T (P_{D \max} - P_D - s_{P_{D \max}}) \\ & - \mu_{P_{ij \max}}^T (P_{ij \max} - |P_{ij}(\delta, V)| - s_{P_{ij \max}}) \\ & - \mu_{Q_{G \min}}^T (Q_{G \min} - Q_G - s_{Q_{G \min}}) \\ & - \mu_{Q_{G \max}}^T (Q_{G \max} - Q_G - s_{Q_{G \max}}) \\ & - \mu_{V_{\min}}^T (V_{\min} - V - s_{V_{\min}}) \\ & - \mu_{V_{\max}}^T (V_{\max} - V - s_{V_{\max}}) \\ & - \mu_s \left( \sum_i \ln s_i \right) \end{aligned} \quad (14)$$

where  $\rho \in \mathbb{R}^n$  and

$$\mu = [\mu_{P_{S \max}} \mu_{P_{D \max}} \mu_{P_{ij \max}} \mu_{Q_{G \min}} \mu_{Q_{G \max}} \mu_{V_{\min}} \mu_{V_{\max}} \mu_s]^T$$

$\mu > 0$ , are the Lagrangian multipliers, and

$$s = [s_{P_{S \max}} s_{P_{D \max}} s_{P_{ij \max}} s_{Q_{G \min}} s_{Q_{G \max}} s_{V_{\min}} s_{V_{\max}}]^T$$

$s \geq 0$ , are the slack variables ( $s = [s_i]$ ).

The marginal costs for the supply and demand can be defined from (14), since

$$\begin{aligned} \frac{\partial \mathcal{L}}{\partial P_{S_i}} &= C_{S_i} - \rho_{S_i} + \mu_{P_{S \max}} = 0 \\ \frac{\partial \mathcal{L}}{\partial P_{D_i}} &= -C_{D_i} + \rho_{D_i} + \mu_{P_{D \max}} = 0 \end{aligned} \quad (15)$$

as  $\partial f_i / \partial P_{S_i} = 1$  and  $\partial f_i / \partial P_{D_i} = -1$ , from the power flow equations. Thus, from (15), the marginal or shadow price for each market participant, i.e., the Locational Marginal Price (LMP), is given by the corresponding Lagrangian multiplier [5], i.e.,

$$LMP_i = \rho_i \quad (16)$$

In (13), the limits on the line power flows are used to somehow represent the system security level, i.e., indirectly represent the system's ATC. These limits are determined off-line, assuming certain “typical” system conditions and contingencies, and hence do not represent the actual operating conditions and the effect of the bidding process on system security. This is obviously one of the major disadvantages of this method, and hence is resolved here by including additional constraints that define a minimum voltage stability margin, as originally proposed for the standard OPF problem in [8]. Thus, the following modifications

are proposed to better account for system security:

$$\begin{aligned}
\text{Min.} \quad & C_S^T P_S - C_D^T P_D \quad (17) \\
\text{s.t.} \quad & f(\delta, V, Q_G, P_S, P_D) = 0 \quad (\text{PF base case}) \\
& f(\delta_c, V_c, Q_{G_c}, \lambda_c, P_S, P_D) = 0 \quad (\text{PF max. load}) \\
& \lambda_c \geq \lambda_{c_0} \quad (\text{min. stab. margin}) \\
& 0 \leq P_S \leq P_{S_{\max}} \quad (\text{supply bid blocks}) \\
& 0 \leq P_D \leq P_{D_{\max}} \quad (\text{demand bid blocks}) \\
& |P_{ij}(\delta, V)| \leq P_{ij_{\max}} \quad (\text{thermal limits}) \\
& |P_{ij}(\delta_c, V_c)| \leq P_{ij_{\max}} \\
& Q_{G_{\min}} \leq Q_G \leq Q_{G_{\max}} \quad (\text{gen. Q limits}) \\
& Q_{G_{\min}} \leq Q_{G_c} \leq Q_{G_{\max}} \\
& V_{\min} \leq V \leq V_{\max} \quad (\text{bus V limits}) \\
& V_{\min} \leq V_c \leq V_{\max}
\end{aligned}$$

where  $\lambda_c$  is a scalar that represents a loading parameter that drives the system to a “critical” point, and thus defines the generation and load powers at the critical point as follows:  $P_{G_c} = P_{G_0} + (1 + \lambda_c + k_{G_c}) P_S$ , and  $P_{L_c} = P_{L_0} + (1 + \lambda_c) P_D$ , with  $k_{G_c}$  representing a variable used to distribute the system losses among the generators in proportion to the generator bids (distributed slack bus model). The loading parameter  $\lambda_c$  is used to guarantee a minimum voltage stability margin  $\lambda_{c_0}$ , and thus indirectly represents the system ATC; however, contingencies cannot be directly included in this problem as opposed to the previously proposed technique. The latter can somewhat be resolved with the choice of the value of  $\lambda_{c_0}$ , as the larger this value, the larger the contingency that the system can withstand, given that this indirectly represents the system stability margin. However, one has to be careful when choosing this margin, as a “large” value might lead to convergence difficulties or a lack of solution all together, which is one of the main problems of this approach. Notice that, in this case, the limits in the transmission line flows are only used to represent actual thermal limits as opposed to the “security” constraints in (13).

The LMPs can also be determined using the corresponding Lagrangian multipliers for (17). Thus, it can be readily shown that

$$\begin{aligned}
\frac{\partial \mathcal{L}}{\partial P_{S_i}} &= C_{S_i} - \rho_{S_i} - \rho_{c_{S_i}}(1 + \lambda_c + k_{G_c}) \quad (18) \\
&\quad + \mu_{P_{S_{\max_i}}} = 0 \\
\frac{\partial \mathcal{L}}{\partial P_{D_i}} &= -C_{D_i} + \rho_{D_i} + \rho_{c_{D_i}}(1 + \lambda_c)
\end{aligned}$$

$$+ \mu_{P_{D_{\max_i}}} = 0$$

where  $\rho_c$  corresponds to the Lagrangian multiplier of the power flow equations at the critical point. Hence, the LMP for each market participant is also given by equation (16), i.e.,  $LMP_i = \rho_i$ . Observe that in (18), the LMP value accounts for the actual bid ( $C_i$ ), the bid limits ( $\mu_{P_{\max_i}}$ ), as well as the stability margin ( $\rho_{c_i}$  and  $\lambda_c$ ).

As with any spot pricing methodology, the binding constraints have a direct effect on the solution of optimization problem (17), and hence are indirectly represented in the price through the value of the corresponding Lagrangian multipliers [5]. For example, generator Q limits do have an effect on the optimal solution and thus affect the LMPs, even though reactive power pricing is not directly considered in the optimization problem.

For inelastic loads, all the previous equations should be changed to assume a fixed demand value. In this case, the load is not treated as a variable parameter within the optimization process. However, one may still use the Lagrangian multipliers at each load bus as the LMPs for the load, since an argument can be made that these represent the marginal costs of supplying power at the load buses [5]. Observe that lack of solution or convergence difficulties may be encountered in this case, depending on the value of the inelastic demand and other system constraints; in other words, the system might not be able to supply the required demand under the given constraints.

The possible convergence difficulties or lack of solution, as well as the integrated approach that somewhat “hides” the effect of the different market components and constraints into a final overall solution, are certainly disadvantages of OPF-based approaches when compared to the use of simple auctions. Furthermore, as opposed to the auction mechanism proposed in this paper, an adequate representation of the effect of contingencies on system security, and the inclusion of a mechanism to allow and account for inelastic load curtailment due to security reasons are not feasible in the OPF methodology proposed in this paper. However, OPF-based techniques yield price values that directly or indirectly account for the effect that the different system constraints have in the market. Furthermore, these methodologies yield a relatively simple mechanism to generate revenues for the ISO to be used in possible system improvements, as demonstrated on the example discussed in the next section.

#### IV. EXAMPLE

The two techniques proposed in the previous section are implemented and compared to standard simple auction and spot pricing techniques based on the results obtained for the test system of Fig. 2 [2].

This is a simple 6 bus test system with 3 generation companies (GENCOs) that provide supply bids, and three energy supply companies (ESCOs) that provide demand bids, as shown in Table I. The data for this system is extracted from [2] and is shown in Tables II and III. The maximum transmission line power flows were determined

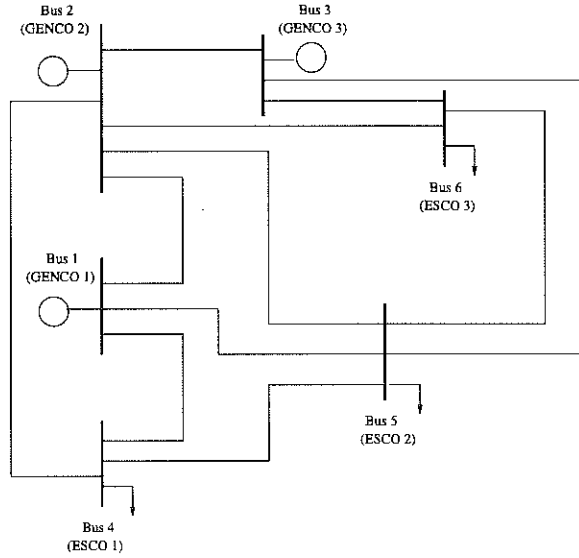


Fig. 2. Test system.

TABLE I  
GENCO AND ESCO BIDS

| Bus<br><i>i</i> | Participant                       | <i>C</i><br>[\$/MWh] | <i>P<sub>max</sub></i><br>[MW] |
|-----------------|-----------------------------------|----------------------|--------------------------------|
| 1               | GENCO 1 ( <i>S</i> <sub>1</sub> ) | 9.7                  | 20                             |
| 2               | GENCO 2 ( <i>S</i> <sub>2</sub> ) | 8.8                  | 25                             |
| 3               | GENCO 3 ( <i>S</i> <sub>3</sub> ) | 7                    | 20                             |
| 4               | ESCO 1 ( <i>D</i> <sub>1</sub> )  | 12                   | 25                             |
| 5               | ESCO 2 ( <i>D</i> <sub>2</sub> )  | 10.5                 | 10                             |
| 6               | ESCO 3 ( <i>D</i> <sub>3</sub> )  | 9.5                  | 20                             |

“off-line” through a series of maximum loading studies using UWPFLOW [12], and based on (N-1) contingency criteria; these limits represent the maximum power flow on the different lines for a maximum loading condition calculated using the load and generation pattern defined by the bids, for a worst contingency scenario. Thermal limits on the lines were assumed to be large, and hence are neglected in this case.

Results for inelastic demand were not obtained for this system, to simplify the analysis of the results as well as to shorten the length of the paper. Nevertheless, as discussed in the previous sections, this problem can be viewed as a special case of demand-side hiding.

#### A. Simple Auctions

A simple auction mechanism, neglecting losses, yields the results depicted in Fig. 3 and Table IV, which included the voltages, total transaction level (*T*), losses, total cost, and the leftover payment for the ISO for comparison purposes. Observe that the results consider that one of the generators (GENCO 2), picks up the losses, thus leaving a cost that has to be covered by the ISO using another auction or market mechanism. The ATC computations, however,

TABLE II  
BUS DATA AT BASE LOADING

| Bus<br><i>i</i> | <i>P<sub>L<sub>0</sub></sub></i> | <i>Q<sub>L<sub>0</sub></sub></i> | <i>P<sub>G<sub>0</sub></sub></i> | <i>Q<sub>G<sub>max</sub></sub></i> | <i>Q<sub>G<sub>min</sub></sub></i> |
|-----------------|----------------------------------|----------------------------------|----------------------------------|------------------------------------|------------------------------------|
| 1               | 0                                | 0                                | 90                               | 150                                | -150                               |
| 2               | 0                                | 0                                | 140                              | 150                                | -150                               |
| 3               | 0                                | 0                                | 60                               | 150                                | -150                               |
| 4               | 90                               | 60                               | 0                                | 0                                  | 0                                  |
| 5               | 100                              | 70                               | 0                                | 0                                  | 0                                  |
| 6               | 90                               | 60                               | 0                                | 0                                  | 0                                  |

| Bus<br><i>i</i> | <i>V</i><br>[p.u.] | <i>V<sub>max</sub></i><br>[p.u.] | <i>V<sub>min</sub></i><br>[p.u.] |
|-----------------|--------------------|----------------------------------|----------------------------------|
| 1               | 1.05               | 1.1                              | 0.9                              |
| 2               | 1.05               | 1.1                              | 0.9                              |
| 3               | 1.05               | 1.1                              | 0.9                              |
| 4               | 0.9754             | 1.1                              | 0.9                              |
| 5               | 0.9677             | 1.1                              | 0.9                              |
| 6               | 0.9930             | 1.1                              | 0.9                              |

TABLE III  
LINE DATA

| Line<br><i>i-j</i> | <i>R<sub>ij</sub></i><br>[p.u.] | <i>X<sub>ij</sub></i><br>[p.u.] | <i>B<sub>i/2</sub></i><br>[p.u.] | <i>P<sub>ij,max</sub></i><br>[MW] |
|--------------------|---------------------------------|---------------------------------|----------------------------------|-----------------------------------|
| 1-2                | 0.1                             | 0.2                             | 0.02                             | -29.88                            |
| 1-4                | 0.05                            | 0.2                             | 0.02                             | 90.62                             |
| 1-5                | 0.08                            | 0.3                             | 0.03                             | 29.14                             |
| 2-3                | 0.05                            | 0.25                            | 0.03                             | 22.62                             |
| 2-4                | 0.05                            | 0.1                             | 0.01                             | 81.67                             |
| 2-5                | 0.1                             | 0.3                             | 0.02                             | 51.43                             |
| 2-6                | 0.07                            | 0.2                             | 0.025                            | 56.3                              |
| 3-5                | 0.12                            | 0.26                            | 0.025                            | 42.13                             |
| 3-6                | 0.02                            | 0.1                             | 0.01                             | 57.27                             |
| 4-5                | 0.2                             | 0.4                             | 0.04                             | -21.83                            |
| 5-6                | 0.1                             | 0.3                             | 0.03                             | -13.67                            |

yield a value of  $\lambda_c = 38.23$  MW corresponding to a minimum load bus voltage limit for a worst contingency on Line 2-4. Hence, since  $\lambda_c < T$ , generator redispatch is necessary to make the transaction feasible.

The generation redispatch procedure of Fig. 1 yields the results depicted on Tables V and VI. This procedure is based on the sensitivity vector  $d\lambda/dp|_c^{(k)}$ , as previously explained; for example, at the initial iteration  $k = 1$  is com-

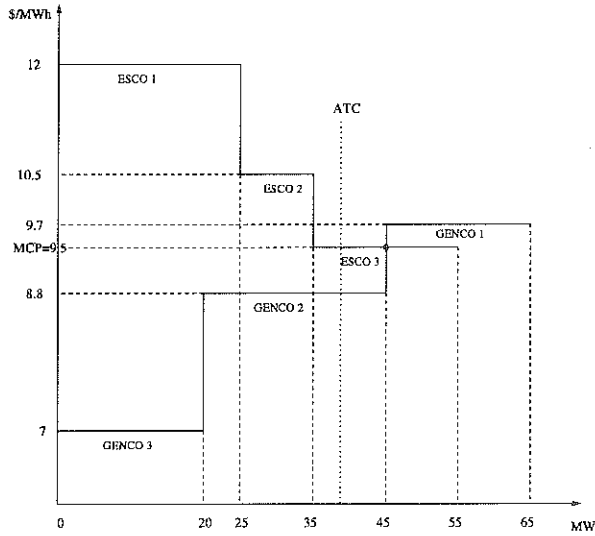


Fig. 3. Solution of simple auction for 6-bus test system.

TABLE IV  
SIMPLE AUCTION RESULTS

| Bus<br><i>i</i> | Part.                 | <i>V</i><br>[p.u.]                             | $\rho = MCP$<br>[\$/MWh] | <i>P</i><br>[MW]                    | Pay<br>[\$/h] |
|-----------------|-----------------------|------------------------------------------------|--------------------------|-------------------------------------|---------------|
| 1               | <i>S</i> <sub>1</sub> | 1.050                                          | 9.5                      | 0.00                                | 0.00          |
| 2               | <i>S</i> <sub>2</sub> | 1.050                                          | 9.5                      | 28.55                               | -271.23       |
| 3               | <i>S</i> <sub>3</sub> | 1.050                                          | 9.5                      | 20.00                               | -190.00       |
| 4               | <i>D</i> <sub>1</sub> | 0.967                                          | 9.5                      | 25.00                               | 237.50        |
| 5               | <i>D</i> <sub>2</sub> | 0.956                                          | 9.5                      | 10.00                               | 95.00         |
| 6               | <i>D</i> <sub>3</sub> | 0.983                                          | 9.5                      | 10.00                               | 95.00         |
| TOTALS          |                       | <i>T</i> =45 MW<br>Losses=3.55 MW<br>ATC=38 MW |                          | Cost=427.50 \$/h<br>ISO=-34.23 \$/h |               |

puted using (6) and is equal to

$$\frac{d\lambda}{dp}\bigg|_c^{(1)} = \begin{bmatrix} d\lambda/dP_{S_1}|_c^{(1)} \\ d\lambda/dP_{S_2}|_c^{(1)} \\ d\lambda/dP_{S_3}|_c^{(1)} \\ d\lambda/dP_{D_1}|_c^{(1)} \\ d\lambda/dP_{D_2}|_c^{(1)} \\ d\lambda/dP_{D_3}|_c^{(1)} \end{bmatrix} = \begin{bmatrix} 0.95 \\ -0.03 \\ 0.03 \\ -1.55 \\ -0.49 \\ -0.09 \end{bmatrix}$$

Table VII shows the final results of the proposed redispatch procedure. Observe the difference between these results and the original simple auction results of Table IV; although the total transaction level is the same, the power levels, marginal prices, and/or transaction costs for each market participant are different.

TABLE V  
RESCHEDULING AND SECURITY COSTS

| <i>k</i> | $\Delta P_{G_1}^{(k)}$<br>[MW] | $\Delta P_{G_2}^{(k)}$<br>[MW] | $\lambda_c^{(k)}/T$ | <i>SC</i> <sub><i>k</i></sub><br>[\$/h] |
|----------|--------------------------------|--------------------------------|---------------------|-----------------------------------------|
| 1        | 5                              | -5                             | 0.90094             | 1                                       |
| 2        | 5                              | -5                             | 0.95647             | 1                                       |
| 3        | 3                              | -3                             | 0.992               | 0.6                                     |
| 4        | 1                              | -1                             | 1.0042              | 0.2                                     |

TABLE VI  
TRANSACTION CONTRIBUTION FACTORS  $TCF_i^{(k)}$ 

| <i>k</i>      | 1     | 2      | 3      | 4      |
|---------------|-------|--------|--------|--------|
| $TCF_1^{(k)}$ | 0     | 0      | 0      | 0      |
| $TCF_2^{(k)}$ | 0.013 | 0.0462 | 0.065  | 0.075  |
| $TCF_3^{(k)}$ | 0     | 0.0329 | 0.0785 | 0.1084 |
| $TCF_4^{(k)}$ | 0.858 | 0.8325 | 0.789  | 0.7606 |
| $TCF_5^{(k)}$ | 0.109 | 0.0884 | 0.0673 | 0.056  |
| $TCF_6^{(k)}$ | 0.02  | 0      | 0      | 0      |

### B. OPF-based Pricing

The results of applying the basic OPF-based procedure (13), which does not properly account for system security, to determine the participants' marginal costs and power levels are depicted in Table VIII. These results were obtained in MATLAB based on an Interior Point optimization approach. In this case, only the upper voltage limits on generator buses play a role, as these voltages are forced to their maximum values by the optimization procedure, which is to be expected, since this would reduce losses and in general improve system security. The latter is demonstrated by the higher value of ATC obtained in this case, which was calculated "off-line" to determine the feasibility of the given transaction. However, observe that the transaction level *T* is smaller, even though the ATC is larger; there is no clear reason for this reduction, which highlights

TABLE VII  
SIMPLE AUCTION WITH REDISPATCH RESULTS

| Bus<br><i>i</i> | Part.                 | <i>V</i><br>[p.u.]                             | $\rho$<br>[\$/MWh] | <i>P</i><br>[MW]                    | Pay<br>[\$/h] |
|-----------------|-----------------------|------------------------------------------------|--------------------|-------------------------------------|---------------|
| 1               | <i>S</i> <sub>1</sub> | 1.050                                          | 9.7000             | 14.00                               | -135.80       |
| 2               | <i>S</i> <sub>2</sub> | 1.050                                          | 9.4897             | 14.56                               | -138.17       |
| 3               | <i>S</i> <sub>3</sub> | 1.050                                          | 9.4949             | 20.00                               | -189.90       |
| 4               | <i>D</i> <sub>1</sub> | 0.966                                          | 9.5926             | 25.00                               | 239.80        |
| 5               | <i>D</i> <sub>2</sub> | 0.956                                          | 9.5249             | 10.00                               | 95.20         |
| 6               | <i>D</i> <sub>3</sub> | 0.984                                          | 9.5020             | 10.00                               | 95.00         |
| TOTALS          |                       | <i>T</i> =45 MW<br>Losses=3.56 MW<br>ATC=45 MW |                    | Cost=430.00 \$/h<br>ISO=-33.87 \$/h |               |

TABLE VIII  
OPF-BASED RESULTS

| Bus<br>$i$ | Part. | $V$<br>[p.u.]                                | $\rho$<br>[\$/MWh] | $P$<br>[MW]                       | Pay<br>[\$/h] |
|------------|-------|----------------------------------------------|--------------------|-----------------------------------|---------------|
| 1          | $S_1$ | 1.100                                        | 8.8415             | 0.0                               | 0.00          |
| 2          | $S_2$ | 1.100                                        | 8.8000             | 24.0                              | -211.31       |
| 3          | $S_3$ | 1.100                                        | 8.9583             | 20.0                              | -179.17       |
| 4          | $D_1$ | 1.026                                        | 9.3651             | 25.0                              | 234.13        |
| 5          | $D_2$ | 1.015                                        | 9.4560             | 10.0                              | 94.56         |
| 6          | $D_3$ | 1.038                                        | 9.2361             | 7.4                               | 68.32         |
| TOTALS     |       | $T=42.4$ MW<br>Losses=1.6 MW<br>ATC=69.37 MW |                    | Cost=397.01 \$/h<br>ISO=6.54 \$/h |               |

the fact that, as previously mentioned, it is not easy to clearly pinpoint all the factors that influence the final solution in an integrated OPF-based technique. Notice that there is some money left from the transaction, which the ISO can use to cover for the transmission system losses.

When system security is directly included in the OPF-based approach, the solution obtained from solving (17) for a minimum "stability" margin value of  $\lambda_{c_0} = 0.1$  p.u. is exactly the same as the one obtained without considering system security. The reason for this is that the required minimum margin is much smaller than the actual system ATC, and hence the corresponding system constraints have no influence in the solution of the optimization problem. However, when this value is significantly increased to  $\lambda_{c_0} = 5.5$  p.u., the solution changes to that shown in Table IX, as the stability margin becomes a binding constraint. Observe that the marginal prices are smaller for all market participants in this case, as one would expect from equations (18), and that the transaction level has decreased slightly, which is also to be expected, since the security constraints now play a role on the solution process, reducing the amount of power that can be transacted through the transmission system. On the other hand, the amount of money left over has increased, which basically means that the ISO can use these funds to take care of losses as well as congestion problems in the system.

## V. CONCLUSIONS

Two distinct techniques to manage and price system security in different electricity market structures are proposed, explained in detail, and briefly tested in this paper. Both techniques are based on basic concepts of voltage stability in power systems, and can be viewed as improvements of methodologies currently used on-line to determine electricity prices in actual markets.

From the tests and analyses, the following main conclusions can be drawn:

- The system ATC can be adequately accounted for in simple auction markets through the iterative technique proposed here. In the case of OPF-based markets, although the current system stability level can be accounted for in

TABLE IX  
OPF-BASED RESULTS INCLUDING SECURITY ( $\lambda_{c_0} = 5.5$  p.u.)

| Bus<br>$i$ | Part. | $V$<br>[p.u.]                                | $\rho$<br>[\$/MWh] | $P$<br>[MW]                       | Pay<br>[\$/h] |
|------------|-------|----------------------------------------------|--------------------|-----------------------------------|---------------|
| 1          | $S_1$ | 1.100                                        | 8.8306             | 0.0                               | -0.00         |
| 2          | $S_2$ | 1.100                                        | 8.7911             | 21.9                              | -192.62       |
| 3          | $S_3$ | 1.100                                        | 8.9422             | 20.0                              | -178.84       |
| 4          | $D_1$ | 1.026                                        | 9.3541             | 25.0                              | 233.85        |
| 5          | $D_2$ | 1.015                                        | 9.4413             | 10.0                              | 94.41         |
| 6          | $D_3$ | 1.039                                        | 9.2154             | 5.5                               | 50.22         |
| TOTALS     |       | $T=40.5$ MW<br>Losses=1.4 MW<br>ATC=66.59 MW |                    | Cost=378.48 \$/h<br>ISO=7.02 \$/h |               |

the solution process, the issue of contingencies cannot be directly included.

- In both techniques, a value for the price of security is generated. However, the OPF-based approach has the advantage of directly generating additional funds for the ISO to take care of system upgrades associated with its losses and security; other mechanisms must be devised and used in simple auctions for this specific purpose.

- The auction-based mechanism is robust and does not present major numerical difficulties. Furthermore, costs of load curtailment for inelastic loads can be readily included in the process. This is not the case for the OPF-based approach, which may present convergence problems and, in some cases, even a lack of solution, especially for inelastic loads; the inclusion of load curtailment costs does not appear to be a simple matter in this case.

- In the OPF-based technique, it is not simple to readily distinguished the different factors that influence the final results, as these are somewhat hidden in the solution. In the case of the auction-based technique, this is relatively simple to do, as the different parts and transactions that make up the market are handled independently of each other. However, iterative procedures are required in this case to be able to account for all the different factors that affect the final solution.

The authors are currently working on testing further the proposed techniques to better understand their benefits and drawbacks, and to determine possible improvements.

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## Discussion of “Pricing system security in electricity markets” by Cañizares et al.

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We observe similar formulas for transfer capability sensitivity in the paper by Cañizares et al. and in the work of Greene et al. [1, 2, 3, 4]. This similarity and the applications suggested in these papers support the usefulness of this transfer capability sensitivity computation. Here we are considering the sensitivity of the transfer margin to thermal, voltage magnitude and some generator reactive power limits; the sensitivity of the transfer margin to voltage collapse is separately addressed in [5] and in Cañizares et al..

The formulation in Greene et al. [1, 2, 3, 4] of the power system equations and the equation of the limit that defines the transfer capability can be rewritten in the notation of Cañizares et al. as follows: The power system equilibrium equations that model the power system at the limit, but not the limit itself, are written

$$0 = f_1(x, \lambda, p) \quad (1)$$

The limit equation is written as

$$0 = E(x, \lambda, p) \quad (2)$$

For example, (2) can have the form  $0 = V_i - V_{imin}$  for a voltage magnitude limit or  $0 = I_i - I_{imax}$  for a thermal limit on line current flow.

Write

$$H(x, \lambda, p) = \begin{pmatrix} f_1(x, \lambda, p) \\ E(x, \lambda, p) \end{pmatrix} \quad (3)$$

Then, according to [1, 2, 3, 4], the sensitivity of the transfer capability  $T$  is

$$D_p T = -\frac{w D_p H}{w D_\lambda H} \quad (4)$$

where  $w$  is a nonzero row vector satisfying

$$w D_x H = 0 \quad (5)$$

and all derivatives in (4) and (5) are evaluated at the limiting condition.

The difference in the formulation (1), (2), with the formulation of Cañizares et al. is that there is no attempt to represent the entire system equations  $f_2$  after the limit is encountered; all that is needed is the scalar limit equation (2) that applies at the limit. Indeed, in the case of power flow and voltage magnitude limits of the form (2), if we assume in Cañizares et al. that these limits are enforced after

they are encountered so that the power system equations are simply augmented by the limit equation after the limit is encountered, then we have

$$f_2(x, \lambda, p) = H(x, \lambda, p) \quad (6)$$

$$w = (-D_x E (D_x f_1)^{-1}, 1) \quad (7)$$

$$\mu = \begin{pmatrix} 0 \\ w D_\lambda H \end{pmatrix} \quad (8)$$

and the sensitivity formula (6) in Cañizares et al. becomes

$$D_p T = (0, (w D_\lambda H)^{-1}) \begin{pmatrix} 0 \\ D_x E (D_x f_1)^{-1} D_p f_1 - D_p E \end{pmatrix} \quad (9)$$

and this simplifies to (4). Thus (4) is a simpler form of formula (6) in Cañizares et al..

Formula (4) is also valid for the sensitivity of margin to a generator reactive power limit if (2) has the form  $Q_{Gi} - Q_{Glim} = 0$  and this is applied to the power system of Southwestern England in [2, chapter 7].

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## The indubitable recognition of the generators contribution to the network voltage support in a market environment

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### Summary

The paper deals with one of the newly defined and very crucial ancillary service in the electricity market: the **generators network voltage support**, simply called “voltage service” which, as well known, gives a very important contribution to the power system operation.

Growing the competition in the electricity market, the System Operators are pushed to achieve high operation standard, so they have to manage the voltage service in a way to warrant an adequate covering of the system demand also under perturbed operating conditions, offering to the customers increased quality, security and economy of the electrical energy supply, as well as to guarantee a correct economical recognition of the contribution to network voltage support given by each generator. In this framework, the paper discusses the complex problem of the correct measure and computing of the power plant contribution to the network voltage regulation, showing the criticism of the present generalized situation where the generators efforts in terms of reactive power delivery/absorption is not generally representative of their concrete network voltage support.

The paper main objective is to show the simplicity, correctness and indubitableness of indicators of the generators contribution to network voltage support, in case the considered generators operate under Secondary Voltage Regulation (SVR)

**Keywords:** ancillary services, voltage service, indicator, energy market, secondary voltage regulation, economic recognition.

### 1. INTRODUCTION

The restructuring of the electric utility industry and the related growing competition in the electricity market have emerged newly defined power plant services as those for network voltage and frequency support which are strongly linked with the performances of the corresponding control systems. Therefore, the correct measure of the power plant controllers and regulators field performances as well as their effective support to the network operation appear to be an unavoidable problem to be concretely solved, to face the emerging need of the correct and indubitable economic recognition of their contribution. This new problem linked with the ancillary services market gives a decisive incentive to the study in depth and to the individualization and specification of practical solutions, which must be

consistent with the law and Energy Authorities official instructions. The network Independent System Operator (ISO) has the management of those new services in a way to guarantee a secure and reliable network operation warranting an adequate balance between offer and demand. This objective can be achieved offering to the customer's additional powered services, which increase the security, reliability and quality of the electrical energy supply and through a correct economic recognition of the different contributions to the services.

Among the power system ancillary services the network voltage support, that is the network voltage regulation through the reactive power control of the main generators and the existing compensating equipments, has the main objective to maintain the network voltages as near as possible to the optimized values in front of the continuous changing of loads and network perturbations, in such a way to achieve high quality, security and economy levels in power system operation.

The correct measure and computing of the power plant control systems performances for the recognition of their network support and related economy is a complex matter to organize, requires a deep knowledge of the different control systems philosophy, functionality and limits and the possible practical solutions are different according with the state of art of the operating control systems not only at power plant level but also at Regional and Central Dispatchers' levels which coordinate the power plants control efforts according with the centralized global system view and control strategy: new and specialized monitoring systems are therefore required. The paper deals with the network voltage service and has the objective to show the simplicity and the correctness of indicators of the generators contribution to network voltage support as well as of the differences of their performances with respect to the contractually agreed control availability, in case the considered generators operate under Secondary Voltage Regulation (SVR) of the local transmission network [1]. In fact, under SVR is generally required a new power plant regulator (PQR), also called “high side voltage control regulator” [2, 3, 4, 5, 6], which is the key to understand the concrete feasibility of the paper proposal. Also from this point of view SVR, originally designed for the management of the previously vertically integrated system, shows its high compatibility with the new structure of the electric industry and market [7, 8, 9] and gives not only an effective solution to network voltage operation but also a strong simplification and clarity on the subject of the fiscal measure of the generators support to the network voltages.

## 2. GENERALITIES ON VOLTAGE SERVICE

The real contribution of each generator to the network voltage support is not simple to define and to measure and it in general becomes a questionable subject when related to an economic recognition. On the other hand the subject under consideration is a well-known, complex matter for many reasons:

- The generator contribution is, in principle, related to the remote control (on-line/off-line, manual/automatic, etc.) operated by the network Dispatcher;
- The correctness at the due time of the power plant operator maneuvers, according with the Dispatcher requests, can not be always monitored and demonstrated;
- The real-time measure of the coordination of the generator reactive power delivery/absorption with respect to the other generators in the power plant or in the neighboring plants, is an onerous not-available information;
- The effectively available generator nominal capability in over and under-excitation, without limitation imposed by stability problems, protection intervention, plant operator unjustified prudence, incorrect changes in the control parameters setting, can not be fully assured by the plant.

Moreover the effectiveness of the generator voltage support is strongly linked with:

- The AVR stability inside a defined operation field as well as the AVR correct dynamics also when operating the over or under-excitation generator limits;
- The correct coordination between the generator protections settings and its available continuous-time operation field;

Lastly the country rules/regulations in force on the generator contribution to network voltage and reactive power control often oblige the generators, in absence of a correct and indubitable monitoring system, to follow apparently simple not-detailed service criteria which, in practice, are often difficult to conform with and allow (that is the worse) the generator operation against the real network needs: excess of over or under excitation with respect to necessity, with consequent exchange of reactive power among the generators internally a plant or located in different plants in the region.

It is evident that the amount of reactive energy itself is not fully representative of the real generator contribution to the voltage service which conversely is substantially related to the generator available reactive power around the normal operating point and to its continuous control, simultaneous and consonant with the controls of the other generators in the same plant and in the neighboring plants.

The “primary voltage regulation” which through the AVR maintain the generator terminal voltage at the set-point value, is not enough for a satisfactory voltage service because the AVR set point are manually controlled by the power plant operators with consequent unsatisfactory performances in terms of timely and coordinated control actions.

The perspective of a new power plant “high voltage side regulator” (PQR) also required by the “secondary voltage regula-

tion” is the true, concrete possibility to achieve the objective of an effective voltage service for the many following reasons:

- The objective to automatically control in real-time and in coordinate way the generators effectively available reactive power resources, can be achieved;
- The generator available capability can be continuously monitored and therefore contractually defined in detail;
- The AVR stability, dynamics and coordination with the generator protections are implicitly guaranteed by PQR which continuously monitors them as necessary conditions for its correct performance;
- A simple but correct and indubitable monitoring system of the effective contribution of each generator to network voltage support can be achieved through PQR facilities for possible comparison with the contractual waited performance and the correct computing of the generator economic recognition.

## 3. THE VOLTAGE SERVICE IN PRESENCE OF A COORDINATED VOLTAGE CONTROL SYSTEM

The coordinated voltage regulation in a transmission network is generally based on a hierarchical control structure (see the Italian hierarchical control scheme in figure 1). This provides a network subdivision into electric areas around the so-called pilot nodes, which are grid busses selected from the strongest ones, on the basis of short-circuit powers and sensitivity matrices computation criteria.

In the Secondary Voltage Regulation (SVR) framework these areas are controlled by suitable signals of “reactive power level”, one for each area, provided by the Regional Voltage Regulator (RVR) apparatuses, which maintain the pilot nodes voltages at the desired values through controlling the reactive powers of those generators which most influence those busses. The generators control is locally achieved at the power plants by means of the already mentioned power plant voltage and reactive power regulator (PQR), which directly acts on the set points of the Automatic Voltage Regulators (AVRs) of the generating units in the plant.

In the Tertiary Voltage Regulation (TVR) framework the central NVR regulator, controls in closed-loop at the utility level the RVRs for a secure and economic operation, establishing the “pilot nodes voltages” pattern, according to the actual network state and the long or short-term forecasting of the optimal pilot nodes voltages and areas reactive power levels.

### 3.1 The Secondary Voltage Regulation (SVR)

SVR is therefore an automatic, effective co-ordination of the reactive power resources of a given network area, mainly those of the generators, with the aim to regulate automatically the voltage of the main bus of each network area in order to meet the objective of keeping up a suitable network voltage profile

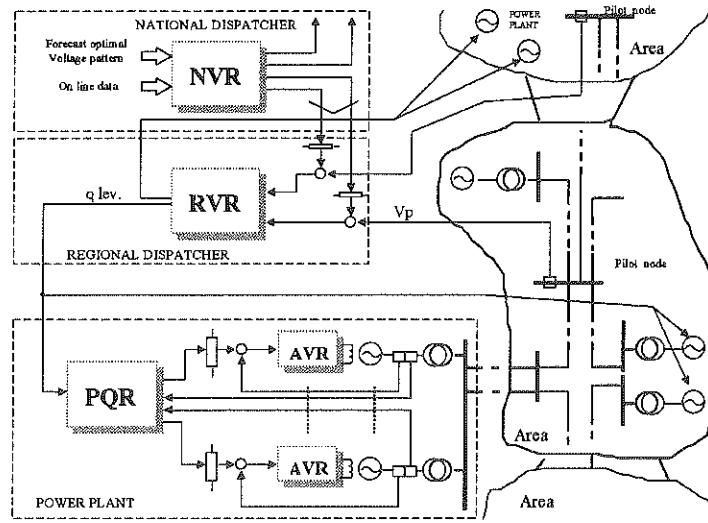


Fig. 1 - Schematic diagram of the Italian hierarchical SVR and TVR system.

in the main busses of the overall transmission network, facing continuously changing reactive power demand and possible grid perturbations.

At the power plant level SVR operates through the mentioned new PQR regulator [2, 10], which automatically controls in real-time the reactive powers of the local generators up to their actual capability limits, according with the real need of the network voltage support. PQR is the key for understanding the concrete and correct way to measure and to indubitably distinguish differences among the contributions to the local voltage support of the area generators.

The information available at the PQR, appropriately elaborated and protected against intrusions, is sufficient for the fiscal monitoring of the generator support to the network voltages.

### 3.2 The Secondary (SVR) and Tertiary (TVR) Voltage Regulations in Italy

The Italian electric power system has an installed capacity of about 73 GW, of which 20 GW come from hydro plants and 53 GW from thermal units. The overall generation on the 380 kV system correspond to an installed capacity of about 35 GW.

The basic SVR structure [10] of the Italian network subdivides the overall country into 18 areas for voltage regulation, chosen on the basis of their geographical and system characteristics, i.e. location and network "density". Each area has a pilot node, with its voltage controlled remotely by a RVR and a set of control generators: the pilot nodes are those with the largest short circuit ratio in a given region. The generators that control each pilot node are then chosen through selecting those which most influence the pilot node voltages.

The overall plan involves all the major power plants connected with both the 380 kV and 220 kV network, for a total reactive power capacity of about 18,000 MVAR. The figure 2 shows the subdivision into areas of the Italian network, pointing out the pilot nodes and the control power plants according to the SVR application plan.

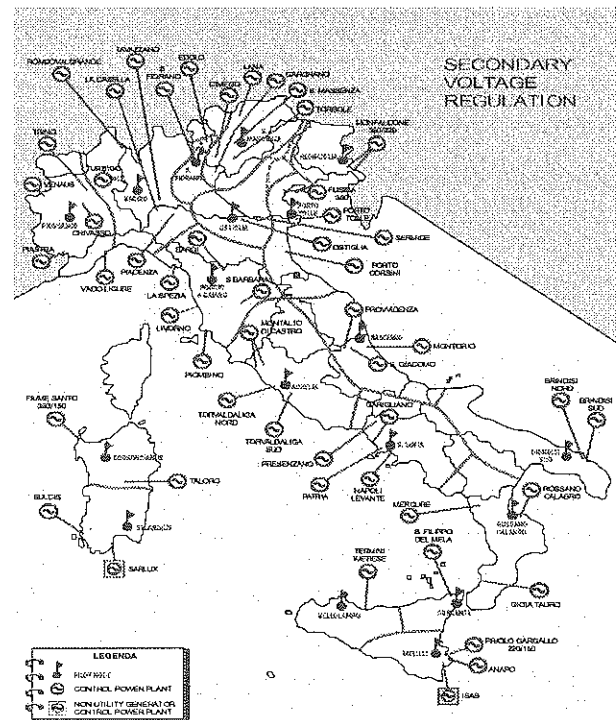


Fig. 2 - Application plan of the SVR in the Italian grid

At the highest hierarchical level, the NVR, scheduled to enter in service within 2002, will define in real-time, for a secure and economic operation, the most appropriate voltage set points of the pilot nodes, on the basis of the actual state of the network and the forecasted optimal voltages and area reactive powers.

With the objective function to be optimized, an adequate compromise can be reached between the need to have a desired voltage pattern, at the pilot nodes, and the need to maximize the area reactive power margins, with respect to the control variable bounds. More precisely, if the reactive power regulation margins available for the SVR control become strongly reduced, as a consequence of severe perturbations or abnormal load patterns which make the network voltage degradation considerable, the TVR attends the transmission network voltage reduction, progressively renouncing to the optimal day-ahead forecasted or short-term planned voltage profile. The coordination between TVR and SVR represents therefore a real chance for the grid operators, in order to achieve a full exploitation of the power transfer capabilities of transmission networks, requirement more and more important in the restructured and liberalized electric energy markets.

### 3.3 *The Voltage Service in Presence of SVR: Rule Played by the Power Plant Voltage and Reactive Power Regulator (PQR)*

In general the PQR objective is the automatic, coordinated and real-time participation to the transmission network voltage support by the power plant units. With this aim PQR contemporarily controls the reactive powers of the power plant generators, in the best case at the same percentage value with respect to the real over and under-excitation limits of each generator. These dynamic limits, which can be computed by PQR according with the generator manufacturer thermal prescriptions and continuously compared with those operating inside the AVR, represent the generator maximum available capability field which can be fully or partially assigned to the voltage service by PQR, according with the defined contractual agreement between the power plant and ISO.

Another constraint on the generators support to the network voltages is the maximum available voltage range at the generator terminal edges, which could limit the exploitation of the generator reactive power reserves. Also this generator allowed voltage field, that can be modulated by PQR, becomes a contractual tie inside the commercial agreement between the power plant and ISO.

Besides the two mentioned generator performance fields, which can be enlarged or restricted through PQR setting and therefore more or less remunerated when confirmed by an indubitable and independent on-line special meter, PQR needs to be continuously checked also for its possible

alternative control functionalities:

- a) Power plant under SVR (tele-controlled by RVR);
- b) Power plant regulating the local HV bus voltage.

The two alternative performances, both in link with the network voltage support, require a differentiated accounting to distinguish the more valuable a) performance by the less valuable b) being defective of coordination with the others area power plants.

According with the mentioned PQR functionalities and limits, the **Power plant performance reference under PQR control**, which in principle would be stated in the “voltage service contract” between ISO and Power plant, is the following:

1. PQR continuous control of all the power plant operating units;
2. Units reactive power availability up to their contractually agreed over and under excitation limits;
3. Generator terminals voltage field availability up to the contractually agreed edges around the nominal value;
4. Generator operation under PQR control, complying with the limits and field previously mentioned at points 2. and 3., for a yearly hours amount not lower than the minimum, contractually agreed, value;
5. Generator operation under a) or b) PQR control functionalities, in agreement with the yearly percentages defined in the commercial agreement, related to the total yearly amount hours fixed at point 4.

Obviously, the more wide is the contractually agreed performance, the more substantial will be the power plant risk and the related economic recognition, when confirmed by field performances measure.

From the commercial point of view the real generator contribution to the network voltage support must therefore be correctly monitored and compared with the contractually agreed performance for an impartial economic recognition or the application/pursuance of penalty clauses: this objective can be achieved by a new “fiscal meter of the power plant generators contributions to network voltage regulation” which collects and elaborates, without intrusion and applying cross correlation and auto-diagnostic criteria, exclusively the PQR available data related to the generators operating states and the main PQR control signal measurements. This meter would be also able to recognize and inform remote terminals about each generator reached performance percentage in agreement with the contractual tie as well as the amount of the differences.

#### 4. VOLTAGE SERVICE INDICATORS

The voltage service evaluation is strongly linked with the generators (the largest on field controllable reactive power reserve) performances effectively devoted to power system operation support for achieving quality, security and economy improvements:

- *Quality* means reduction of: the voltage variations in the network busses due to load changes and system perturbations; the amplitude and duration of the voltage transients following network perturbations; the load disconnections for voltage problems.
- *Security* means: improved stability and therefore reduction of the protections interventions; reduction of voltage collapse risk; reduction of the machinery voltage stress and therefore the fatigue of generators insulation.
- *Economy* means reduction of: losses in the electrical lines and machinery; investments for additional MVARs, new electrical lines and generating/compensating plants; costs for voltage support warm reserves; time recovery, following load rejection due to voltage problems.

The achievement of those benefits is strictly linked with the automation level of the network control system, the availability of reactive power resources and their effective and timely coordination for facing the real-time power system changes.

In absence of an automatic transmission network voltage control system, the voltage service cannot be significantly improved with respect to the classical off-line reactive power dispatching, which cannot effectively follow the real-time continuous voltages changes in the network.

In addition the real contribution given by each reactive power resource is out of a reliable monitoring and control: even considering the delivered or absorbed amount of the power plant reactive powers, it cannot be excluded possible compensation with neighboring plants. Moreover the amount of reactive power is simply representative of the average operating condition in a given network area, while the reactive power variations around the normal operating conditions are the most effective in terms of system voltage regulation, when adequately and timely coordinated up to the limits according to the real network need.

The presence of a coordinated voltage control system (SVR and TVR) therefore allows an effective voltage service with significant improvement in terms of quality, security and economy of power system operation. In addition it strongly simplify the correct recognition of each generator contribution to the voltage service.

Starting from this point of view and just considering the generators under SVR those really accredited to perform a recognizable voltage service, it becomes understandable the proposal to base the indicator of the single generator contribution to the voltage service on the **real-time checkable availability and concrete usability of the contractually agreed capability limits**. On this concern the points 1...5. previously mentioned at paragraph 3.3 represent

the basic reference of the commercial agreement, between ISO and Power Plant, on the generator contribution to voltage service.

With the aim to correctly checking the generator real performance through comparison with the contractual obligations, the following indicators are proposed.

##### 4.1 Index of Generator Available Capability

For each generator under its control, PQR computes instant by instant, taking into account the voltage and active power measurements at the stator terminal edges, the corresponding reactive power limit values in over and under excitation to be imposed to the generator as well as checks their consistency with those operating on the AVR. Obviously the generator limits in PQR can be selected/ changed by the power plant operator according with the generators operation/security needs. The measure of the dynamic generator reactive power field is sent by PQR to the new “voltage service meter” for a real-time comparison with the corresponding limit values continuously computed by the meter on the base of the capability curves parameters contractually agreed.

Now, till when the generator reactive power limit  $Q_{lim}$  value corresponds to the contractual  $Q_{lim\_contr}$  value both in over and under excitation, then the generator available capability is 100%, otherwise it becomes lower. The availability value is assumed 0% when the generator is outside the PQR control.

According to what above, a significant index of the generator contribution to the voltage service in terms of available reactive power capability is the following:

$$I_q(T) = 100 / T \int_0^T (Q_{lim}(t) / Q_{lim\_contr}(t)) dt \quad (1)$$

which represents the percentage average value in the interval T of the correspondence between the real and the contractual generator capability.

That means  $I_q = 100\%$  only when  $Q_{lim} = Q_{lim\_contr}$  along the overall period T during which the generator is continuously operated under PQR control. To be noticed that  $I_q$  could be lower than 100% also when the voltage limits, at the generator terminal edges, do not allow reaching the reactive power limits

##### 4.2 Index of Generator Available Voltage Field

For each generator under its control, PQR generally allows to fix the available stator voltage field around the nominal value as well as to check its consistency with the protections operating on the generator and to signal the operating condition forced at a voltage limit. Obviously the generator voltage limits in PQR can be changed by the power plant operator according with the plant operation needs and

machinery security reasons, which could result more restrictive in comparison with the nominal values indicated by the alternator manufacturer. This possible generator voltage field reduction could penalize the exploitation of the allowed generator capability and therefore its measurement is required. Because the real voltage limit values are not a priori known, they are recognized and memorized by the new “voltage service meter” when reached and signaled by PQR. Analogously their changes are updated when recognized. Therefore in PQR the generator operating voltage limits are the most recently measured on field and their values can be used for a real-time comparison with the corresponding limit values agreed in the generator voltage service contract.

Now, till when the generator voltage field  $|V_n - V_{lim}|$  value corresponds to the contractual  $\Delta V_{contr}$ , then the generator available voltage field is 100%, otherwise it becomes lower. The availability value is considered 0% when the generator is outside the PQR control. Therefore a significant index of the generator contribution to the voltage service in terms of available voltage field is the following:

$$I_v(T) = 100 / T \int_0^T (|V_n - V_{lim}(t)| / \Delta V_{contr}) dt \quad (2)$$

which represents the percentage average value in the interval T of the correspondence between the real and the contractual generator voltage field. That means  $I_v = 100\%$  only when  $V_{lim}(t) = V_{lim\_contr}$  along the overall period T during which the generator operated under PQR control.

#### 4.3 The Power Plant New Meter for Voltage Service

The generator on field really available performances to be used for network voltage service can not be a priori known, and what declared by the power plant on this concern could change or result not feasible, without any possible reliable check and warranty.

The previously announced power plant new concept meter, which fully depends on the presence in the power plant of the new voltage an reactive power regulator (PQR), will be able to compute in real-time either the previously mentioned  $I_q$  and  $I_v$  indices or the intervals, inside the period T (T could last one year), during which:

- $I_q = 100\%$ ;
- $0\% < I_q < 100\%$ ;
- $I_q = 0\%$
- $I_v = 100\%$ ;
- $0\% < I_v < 100\%$ ;
- $I_v = 0\%$

for each of the two possible alternative PQR regulating functions a) or b) mentioned at 3.3 paragraph.

Moreover the new meter would compute for each generator in the plant the amounts, in the period T, of the reactive energies, both in over and under excitation.

It has to be pointed out that the progressive values of all the generator performance indicators, calculations and measurements can be monitored (but not modified) by the power plant operators and ISO, at any time, through telecommunications. ISO, at the time of the contract definition/renewal is authorized to remotely setting the contractual parameters, which represent the generator performance references.

On the base of the values reached along the period T by all the mentioned generator performance indicators, it will be possible in one hand to compare in a precise way the generator availability and contribution to voltage support with the elements of the voltage service contract, and in the other hand to attribute to each generator a very correct and indubitable economic recognition of its network voltage support.

#### 5. SIMPLICITY, CORRECTENESS AND INDUBITABLENESS OF THE PROPOSED INDICATORS

**Simplicity:** The proposed methodology to compute and monitor indicators based on real-time measurements of the generator contribution to voltage service is very simple to apply when the power plant is operating under PQR. The main reasons are:

- The demanded analytical functions are simply integrals and counters of the present values of measures and logic states available at the PQR;
- The proposed new meter exclusively interfaces the PQR and monitories in real-time the computed indices to the power plant and remote (ISO) operators by ordinary local and remote telecommunications.

**Correctness :** Till when the generator is under PQR control, they are continuously monitored and checked by PQR the on-line real coordination of the generator protections with the available normal operation fields as well as the AVR correct performance. In case a generator has problems on primary voltage regulation, it is automatically shut out the PQR control and maintenance AVR requirement signal is sent by PQR to the plant operators.

The operation under PQR allows the correct use of the generator reactive power up to the contractually agreed capability limits, avoiding useless reactive power dispersions or too protective interventions by the plant operators. Possible lack of coordination between the AVR and PQR capability curves is signaled by PQR to the operator, requiring a correct setting. Under PQR all the units move in a coordinate way using just the minimum reactive power reserves to maintain the network to the desired



voltage value. No useless reactive power exchanges among generators will be possible under PQR, especially in presence of SVR which co-ordinates all the PQRs.

According to the fact that the generator reactive power must be timely used for what necessary and without limitation inside the agreed capability, the generator economic recognition is necessarily based on the availability of the continuously checked generators capability limits which are correctly computed and assured during the operation by PQR, also because possible differences with the contractual values are timely and automatically taken into account by the new meter.

**Indubitableness:** The proposed methodology is fully based on real-time field measurements of the generator performance, the same measurements used by PQR with a large surveillance on the data congruity. Therefore the real generator availability for voltage service can be continuously monitored and stored. The proposed new meter takes all the information it needs, including the modifications operated at any time on PQR and its out of service or maintenance periods. Furthermore, the new meter would apply the necessary mechanisms for checking the congruity of the acquired data and elaborating cross-correlations. Lastly the new proposed meter, besides the auto diagnostic algorithms, would actuate protective mechanisms against intrusion also sending remote alarm signals.

## 6. CONCLUSIONS

The paper describes in detail a simple, correct and indubitable monitoring of the contribution of each generator to network voltage service, when operating under PQR control. The proposal is definitely based on the continuous time measuring and monitoring of the real available capability field of each generator when the reactive power can be continuously and profitably controlled by PQR. The function which determines the practicable reactive power field, taking also into account its dependence from the unit terminal voltage, can be contractually fixed inside the thermal limits imposed by the over and under-excitation AVR limits as well as consistently actuated by PQR. The fiscal computing for each generator of the progressive time period during which the available capability field corresponds to the contractual value and the comparison with the agreed yearly percentage, allows the proposal of an indubitable performance index of both:

- The generator reactive power reserve available in real time and usable without limitations for network voltage support
- The coherence of this result with the contractual tie.

This and others indicators inferred from the proposed method and related to the possible different generator operating conditions and their lengths are computed through

counters and their usefulness shown.

The simplicity, correctness and indubitableness of the proposed method encourages for a practical extensive application of the new meter fully dedicated to voltage service monitoring and accounting with the aim of effectively supporting a correct economic recognition of the generator contribution to network voltage regulation.

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## POWER EXCHANGE BEHAVIOR IN A HYDROTHERMAL SYSTEM: THE CHILEAN CASE

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### SUMMARY

In this paper a study of a proposed market power exchange in the Chilean system is analyzed.

The study is carried out through a test case framework, which is used to analyze structural behavior of the market agents. Test cases reproduce real scenarios on the longitudinal Chilean Interconnected System (CIS), where physical bilateral contracts (PBC) and strategic bidding are simulated.

### 1. INTRODUCTION

Starting in Latin America, new electric sector regulations were set in Chile in 1982, Argentina in 1992, Perú in 1993, Bolivia and Colombia in 1994, the Central American countries of Panamá, El Salvador, Guatemala, Nicaragua, Costa Rica and Honduras in 1998 [1, 2]. In Europe this process started with the U.K. in 1989, followed by the Scandinavian countries in 1990-1995 [2, 3]. For the member states of the European Union, 1996 directive of the European Parliament defined the framework of a common European electricity market and required all member states to introduce competition in the electricity supply sector by February 1999 [4]. Reforms in the structure of electricity services in the US started with the California restructuring proposal in 1997 [5] and the Federal Energy Regulatory Commission (FERC) creating open access conditions [6]. Norway in 1987 and Australia in 1991 also created competition condition in the electrical sector [2, 7]. Currently there are a growing number of countries in Asia and East-Europe that will join the worldwide restructuring process. As a result, worldwide market organization of the power industry presents a wide range of arrangements, which may be classified in the following three basic categories [1– 3], [7]:

- Pool market,
- Market based on physical bilateral contracts, and
- Market based on financial bilateral contracts.

Real markets throughout the countries correspond to a mix of these categories [12]. This paper focuses on markets based on physical bilateral contracts and a power

exchange market, which include daily and intraday markets.

The Chilean Interconnected System (CIS) covers an area of 2000 km in length, and supplies a peak load of 4800 MW, with nearly 600 buses. The major load is located in Santiago, Chile's capital, located in the central part of the system. Due to the longitudinal structure, there are power flows from the southern part of the country to the central part; mainly transmitted through 500 kV lines; and from the northern part to the central part, mainly transmitted through 220 kV lines. In both corridors there has been congestion in the last years. The annual load increase rate, during the last seven years, has been approximately 7% on average. In addition, there is a 65% of hydro generating plants; mainly in the southern part; and 35% of thermal units, mainly located in the central and northern areas. Among the hydro plants there is a few with a large reservoir, which enable them to deliver full capacity for a long period of time. All the above features impose constraints to competition in an open market and many issues, such as ancillary services, appear as critical during the operation. For that reason, the government is proposing a change in the regulatory frame, which consists of a migration from the actual mandatory pool structure with audited costs to a new market based on physical bilateral contracts (PBC) and a power exchange (Px) [14]. The analysis of the impact of this change is the main motivation for this work.

The paper presents a brief description of the proposed market structure for the Chilean system. This description focuses on the energy market only. Thus, power market transactions, which are related to the capacity of the system, and ancillary services are not included in the study.

The structural behavior of the market agents is analyzed in a test case framework, which is constructed in order to reproduce real scenarios on the longitudinal CIS system. The analysis covers physical bilateral contracts (PBC) and strategic bidding. The results show that the performance of a market power exchange for a longitudinal system is critically dependent on the way the

transmission congestion and bidding process for hydro and thermal units are designed.

## 2. PROPOSED MARKET STRUCTURE

The Chilean Power Exchange is proposed as a single-round auction, where the supply bids are matched with demand bids by a market operator (MO), without any additional iteration with market participants. Bids consist of a pair of values corresponding to quantity (MWh) and price (US\$/MWh), which are submitted privately to the MO. Thus, for each hour a supply curve is built considering all the bids ordered by increasing prices. Similarly, a demand curve is built with the offers of buyers. The intersection of the supply and demand curves determines a single uniform market-clearing price and the generation units in operation. Then, this preliminary schedule is sent to the Independent System Operator (ISO), which incorporates all the constraints of the transmission and security of the system. In addition, it is also possible to establish bilateral contracts between buyers and sellers, which also have to be submitted to the ISO for the general coordination.

Finally, in order to fulfill additional operation requirements, an ancillary services auction, is also considered. In Figure 1 it is depicted this market structure.

The proposed market structure is similar to the market of Spain. However, there are some key features of CIS, which need to be addressed carefully in order to design a suitable Px in Chile. These characteristics are:

- Reduced number of producers. There are three main producers, which account for 95% of the market. The HHI index [15] for market concentration is 3829, i.e., the market is highly concentrated.
- High demand increase ratio (above 7% on average),
- Network is strongly longitudinal, with congestion in some key lines of the system,
- Hydrothermal production, with near 65% hydro and 35% thermal,
- High variability in weather conditions may lead to dry seasons or excess in the water reservoirs for different years,
- There are two major reservoirs with inter-annual capabilities.

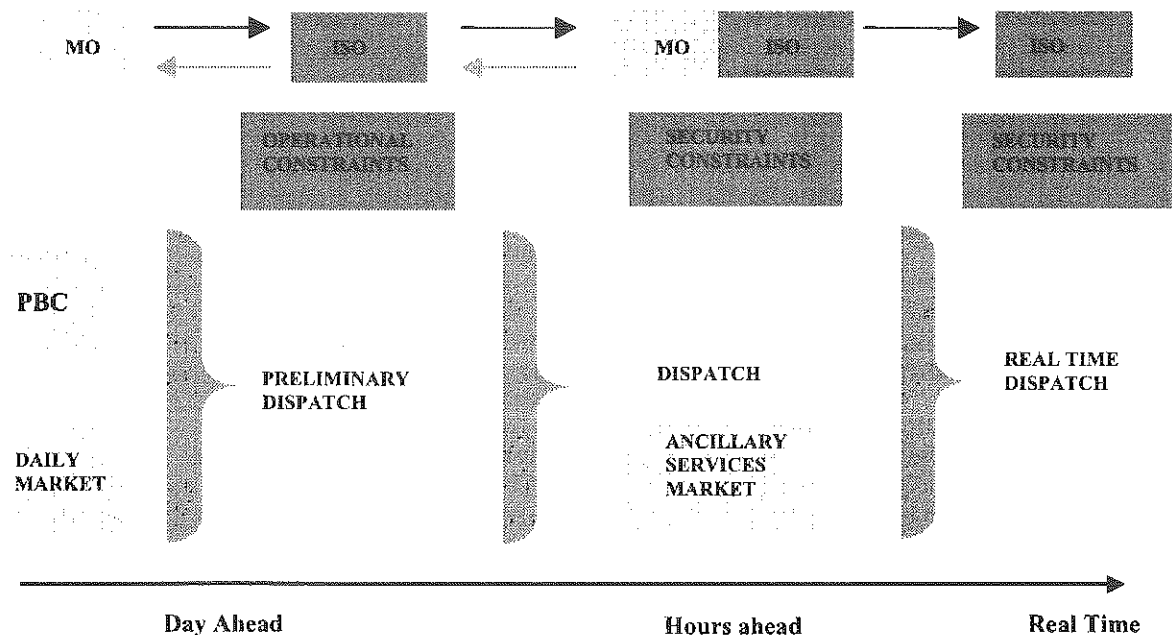


Figure 1. Market Structure

### 3. PHYSICAL BILATERAL CONTRACTS

In this section the effects of PBC in the operation of the proposed market structure is analyzed. A case study is constructed with real operational conditions and the settings of the proposed Px.

#### 3.1 Definitions

Lets start defining the total demand of the system ( $D_T$ ) according to the expression

$$D_T = D_{PBC} + D_{CPx} \quad (1)$$

Where  $D_{PBC}$  stands for the demand with bilateral contracts and  $D_{CPx}$  is the demand dealing directly with the Px.

Thus, a Consumer has two possibilities to buy energy, either through PBC with generating companies or through buying directly from the power exchange. Consumer here must be understood as a big consumer with more than 200 kW. All other consumers will be considered as regulated demand, which is usually served through a distribution company with PBC. In addition, generating companies can also submit buying bids to the Px for its PBC contracted.

By taking a specific period of time, the income from the energy market of a generating company (Bfi) can be written as

$$Bfi = E_{PBCi} \times (P_{PBCi} - P_c) + E_i \times (P_c - C_{mgi}) \quad (2)$$

Where  $E_{CBFi}$  is the contracted energy of generating unit  $i$  in PBC,

$P_{CBFi}$  is the contracted price of that PBC,

$P_c$  is the clearing price,

$E_i$  is the dispatched energy of unit  $i$ ,

$C_{mgi}$  marginal production cost of generating company  $i$ ,

Bfi income of generating company  $i$ .

The total energy balance for the system is

$$\sum E_i = D_T + \text{Losses} \quad (3)$$

where the addition includes all the generating companies.

The result of a particular company will depend on both, the balance in the bilateral contracts (the first term in the right hand side of Equation 2), and the balance in the power exchange transactions (the second term in the right hand side of the same equation). Thus, as the clearing price is unknown in advance, there is uncertainty regarding the PBC results and, therefore, they are a key

factor in the economical performance of companies. For this reason, a numerical exercise to quantify this effect is carried out in the next section.

#### 3.2 Case Study

We use de CIS as a test case with a demand of 1000 GWh. Three scenarios where the PBC are 75%, 50% and 10% of total demand, are studied. The test conditions are as follows:

- Four generating companies,
- PBC are assumed to be contracted at the same price for all the generators,
- No transmission losses or congestion are considered,
- In addition, the demand of the PBC is contracted at the same price of 30 mills/kWh for all generators.

For each case, five different prices for PBC transactions are studied: Alternative A, 20 mills/kWh; Alternative B, 25 mills/kWh, Alternative C, 30 mills/kWh, Alternative D, 25 mills/kWh and Alternative E, 30 mills/kWh.

#### A. The Base Case

The bidding of generating companies is constructed with two blocks of energy. The first block, an amount equal to the energy of its PBC, is offered at a price equal to its marginal cost. The second block of energy, which in this case is the rest of the available energy of the company, is offered at a superior price. On the other hand, in order to simulate the lack of elasticity in the demand, all the energy is aggregated in one block ( $D_{CPx} + D_{PBC}$ ) at a same price. The bidding information of the base case is presented in Table 1.

TABLE 1. Bidding Information

| Agent               | 1 <sup>st</sup> Block |                 | 2 <sup>nd</sup> Block |                 |
|---------------------|-----------------------|-----------------|-----------------------|-----------------|
|                     | Price<br>[mills/kWh]  | Energy<br>[GWh] | Price<br>[mills/GWh]  | Energy<br>[GWh] |
| Company1            | 15                    | 100             | 20                    | 200             |
| Company2            | 10                    | 100             | 20                    | 300             |
| Company3            | 15                    | 200             | 20                    | 300             |
| Company4            | 20                    | 100             | 25                    | 300             |
| $D_{CPx} + D_{PBC}$ | 30                    | 1000            | 0                     | 0               |

The clearing price for the base case is obtained at the crossing of offer and demand curves, as depicted in Figure 2.

In Figure 2, the clearing price ( $P_c$ ) is 25 mills/kWh and the total energy is 1000 GWh with the following distribution:

- 800 GWh are obtained from the full delivery of company 1 (200 GWh), company 2 (300 GWh) and company 3 (300 GWh),
- 100 GWh come from the first block of company 4,

- 100 GWh come from the second block of company 4.

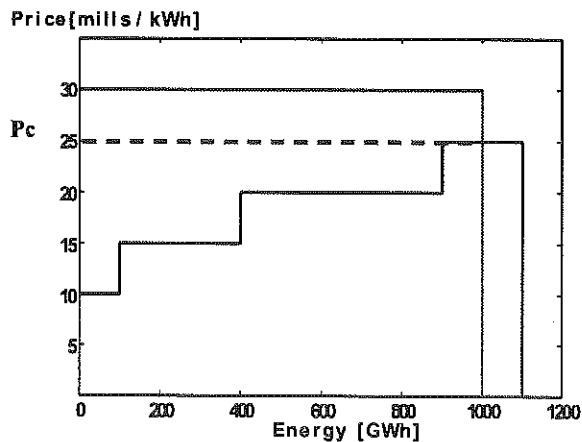


Figure 2. Clearing Price.

Note that in the base case all marginal costs are inferior to the clearing price. In other words, all generating companies are in service.

#### B. The effect of changing the percentage of PBC in the market

In this subsection, the impact of PBC on the market is studied. To achieve this, we analyse the effect of changing the percentage of PBC in the market transactions. We have two extreme cases. On one hand, if the percentage of PBC is null, then we have a pure Px market, as it was nearly practiced in California. On the other hand, if the amount of PBC approaches the full demand, every company must satisfy its own contracted energy at all times. According to the proposed Px framework, this task may be carried out by each company, which has three alternatives: with its own generating units, by contracting another producer as a supplier, or by a mix of both. In this study we assume that every generating company submit a buying bid for the full amount of its PBC.

#### CASE I. PBC are 50% of Total Demand

In this case the PBC are half of the full load of the system. The economical results are shown in Table 2.

In Table 2 the first column shows the identification of the company, the second column indicates the income from PBC for each company ( $I_{PBC}$ ), and the third column contains the income from sales of energy in the Px ( $V_B$ ). The fourth column shows the total energy that is purchased at clearing price for covering the PBC ( $C_B$ ). The fifth column contains the production costs ( $C_P$ ), the sixth column indicates the results at the power exchange

( $Re$ ) and the last column shows the total income from the energy market ( $B_T$ ).

Table 2. Results for 50% of PBC

| Alternative A |                    |                |                |                  |               |                |
|---------------|--------------------|----------------|----------------|------------------|---------------|----------------|
| Company       | $I_{PBC}$<br>MUS\$ | $V_B$<br>MUS\$ | $C_B$<br>MUS\$ | $C_P$<br>MUS\$   | $Re$<br>MUS\$ | $B_T$<br>MUS\$ |
| Utility 1     | 2000               | 5000           | 2500           | 3000             | -500          | 1500           |
| Utility 2     | 2000               | 7500           | 2500           | 3000             | 2000          | 4000           |
| Utility 3     | 4000               | 7500           | 5000           | 4500             | -2000         | 2000           |
| Utility 4     | 2000               | 5000           | 2500           | 4000             | -1500         | 500            |
| TOTAL         | 10000              | 25000          | 12500          | 14500            | -2000         | 8000           |
| Alternative B |                    |                |                |                  |               |                |
| Company       | $I_{PBC}$<br>MUS\$ | $V_B$<br>MUS\$ | $C_B$<br>MUS\$ | $C_P$<br>[MUS\$] | $Re$<br>MUS   | $B_T$<br>MUS\$ |
| Utility 1     | 2500               | 5000           | 2500           | 3000             | -500          | 2000           |
| Utility 2     | 2500               | 7500           | 2500           | 3000             | 2000          | 4500           |
| Utility 3     | 5000               | 7500           | 5000           | 4500             | -2000         | 3000           |
| Utility 4     | 2500               | 5000           | 2500           | 4000             | -1500         | 1000           |
| TOTAL         | 12500              | 25000          | 12500          | 14500            | -2000         | 10500          |
| Alternative C |                    |                |                |                  |               |                |
| Company       | $I_{PBC}$<br>MUS\$ | $V_B$<br>MUS\$ | $C_B$<br>MUS\$ | $C_P$<br>MUS\$   | $Re$<br>MUS\$ | $B_T$<br>MUS\$ |
| Utility 1     | 3000               | 5000           | 2500           | 3000             | -500          | 2500           |
| Utility 2     | 3000               | 7500           | 2500           | 3000             | 2000          | 5000           |
| Utility 3     | 6000               | 7500           | 5000           | 4500             | -2000         | 4000           |
| Utility 4     | 3000               | 5000           | 2500           | 4000             | -1500         | 1500           |
| TOTAL         | 15000              | 25000          | 12500          | 14500            | -2000         | 13000          |
| Alternative D |                    |                |                |                  |               |                |
| Company       | $I_{PBC}$<br>MUS\$ | $V_B$<br>MUS\$ | $C_B$<br>MUS\$ | $C_P$<br>MUS\$   | $Re$<br>MUS\$ | $B_T$<br>MUS\$ |
| Utility 1     | 1500               | 5000           | 2500           | 3000             | -500          | 1000           |
| Utility 2     | 1500               | 7500           | 2500           | 3000             | 2000          | 3500           |
| Utility 3     | 3000               | 7500           | 5000           | 4500             | -2000         | 1000           |
| Utility 4     | 1500               | 5000           | 2500           | 4000             | -1500         | 0              |
| TOTAL         | 7500               | 25000          | 12500          | 14500            | -2000         | 5500           |
| Alternative E |                    |                |                |                  |               |                |
| Company       | $I_{PBC}$<br>MUS\$ | $V_B$<br>MUS\$ | $C_B$<br>MUS\$ | $C_P$<br>[MUS\$] | $Re$<br>MUS\$ | $B_T$<br>MUS\$ |
| Utility 1     | 1000               | 5000           | 2500           | 3000             | -500          | 500            |
| Utility 2     | 1000               | 7500           | 2500           | 3000             | 2000          | 3000           |
| Utility 3     | 2000               | 7500           | 5000           | 4500             | -2000         | 0              |
| Utility 4     | 1000               | 5000           | 2500           | 4000             | -1500         | -500           |
| TOTAL         | 5000               | 25000          | 12500          | 14500            | -2000         | 3000           |

For all companies, alternatives A, B and C render a positive total income. On fact, alternative C shows the greater values due to its maximum price for PBC (30 mills/kWh). Here, the highest income is for Utility 2 because this company has the least marginal cost, i.e., it is the most efficient company in service.

For the alternative D the Utility 4 obtains a null income, in other words, this company covers its operational costs without surplus. The other utilities can still obtain positive income.

The worst result is exhibited under alternative E, where Utility E shows a negative income. This is due to the lowest selling price for the PBC of 10 mills/kWh, whereas this company has to buy its contracted energy at a price of 25 mills/kWh. On the other hand, the results at the power exchange report an insufficient income to cover this deficit.

**CASE II. PBC are 75% of Total Demand**

In this case the PBC are 75% of the full load of the system. The economical results are shown in Table 3.

**Table 3. Results for 75% of**

| Alternative A |               |               |               |               |               |               |
|---------------|---------------|---------------|---------------|---------------|---------------|---------------|
| Compy         | ICBF<br>MUS\$ | VB<br>[MUS\$] | CB<br>[MUS\$] | CP<br>[MUS\$] | Re<br>[MUS\$] | Bf<br>MUS\$   |
| Utility 1     | 3000          | 5000          | 3750          | 3000          | -1750         | 1250          |
| Utility 2     | 3000          | 7500          | 3750          | 3000          | 750           | 3750          |
| Utility 3     | 6000          | 7500          | 7500          | 4500          | -4500         | 1500          |
| Utility 4     | 3000          | 5000          | 3750          | 4000          | -2750         | 250           |
| TOTAL         | 15000         | 25000         | 18750         | 14500         | -8250         | 6750          |
| Alternative B |               |               |               |               |               |               |
| Compy         | ICBF<br>MUS\$ | VB<br>[MUS\$] | CB<br>[MUS\$] | CP<br>[MUS\$] | Re<br>[MUS\$] | Bf<br>[MUS\$] |
| Utility 1     | 3750          | 5000          | 3750          | 3000          | -1750         | 2000          |
| Utility 2     | 3750          | 7500          | 3750          | 3000          | 750           | 4500          |
| Utility 3     | 7500          | 7500          | 7500          | 4500          | -4500         | 3000          |
| Utility 4     | 3750          | 5000          | 3750          | 4000          | -2750         | 1000          |
| TOTAL         | 18750         | 25000         | 18750         | 14500         | -8250         | 10500         |
| Alternative C |               |               |               |               |               |               |
| Compy         | ICBF<br>MUS\$ | VB<br>[MUS\$] | CB<br>[MUS\$] | CP<br>[MUS\$] | Re<br>[MUS\$] | Bf<br>[MUS\$] |
| Utility 1     | 4500          | 5000          | 3750          | 3000          | -1750         | 2750          |
| Utility 2     | 4500          | 7500          | 3750          | 3000          | 750           | 5250          |
| Utility 3     | 9000          | 7500          | 7500          | 4500          | -4500         | 4500          |
| Utility 4     | 4500          | 5000          | 3750          | 4000          | -2750         | 1750          |
| TOTAL         | 22500         | 25000         | 18750         | 14500         | -8250         | 14250         |
| Alternative D |               |               |               |               |               |               |
| Compy         | ICBF<br>MUS\$ | VB<br>[MUS\$] | CB<br>[MUS\$] | CP<br>[MUS\$] | Re<br>[MUS\$] | Bf<br>[MUS\$] |
| Utility 1     | 2250          | 5000          | 3750          | 3000          | -1750         | 500           |
| Utility 2     | 2250          | 7500          | 3750          | 3000          | 750           | 3000          |
| Utility 3     | 4500          | 7500          | 7500          | 4500          | -4500         | 0             |
| Utility 4     | 2250          | 5000          | 3750          | 4000          | -2750         | -500          |
| TOTAL         | 11250         | 25000         | 18750         | 14500         | -8250         | 3000          |
| Alternative E |               |               |               |               |               |               |
| Compy         | ICBF<br>MUS\$ | VB<br>[MUS\$] | CB<br>[MUS\$] | CP<br>[MUS\$] | Re<br>[MUS\$] | Bf<br>[MUS\$] |
| Utility 1     | 1500          | 5000          | 3750          | 3000          | -1750         | -250          |
| Utility 2     | 1500          | 7500          | 3750          | 3000          | 750           | 2250          |
| Utility 3     | 3000          | 7500          | 7500          | 4500          | -4500         | -1500         |
| Utility 4     | 1500          | 5000          | 3750          | 4000          | -2750         | -1250         |
| TOTAL         | 7500          | 25000         | 18750         | 14500         | -8250         | -750          |

Same as in the previous case, all companies render a positive total income for alternatives A, B and C. But in this case, alternative A shows lower values than in the previous case. On the other hand, alternative B shows the same results and alternative C obtains greater values as compared to the previous case. Here, the highest income is again for Utility 2, the most efficient company in service. This utility shows a better performance than in the previous case.

For alternatives D and E, results are worst than the previous case. On fact, here for alternative E three utilities show negative results, and just Utility 2 shows a positive balance.

Thus, in this case results are more extreme than in the precedent case. On one hand, they exhibit greater income, for case C, and on the other hand a worst result for alternative E.

**CASE III. PBC are 10% of Total Demand**

In this case the PBC are 10% of the full load of the system. In Table 4 a summary of the economical results is presented.

**Table 4. Results for 10% of PBC**

| Alternative A |                 |               |               |               |               |             |
|---------------|-----------------|---------------|---------------|---------------|---------------|-------------|
| Compy         | ICBF<br>[MUS\$] | VB<br>[MUS\$] | CB<br>[MUS\$] | CP<br>[MUS\$] | Re<br>[MUS\$] | Bf<br>MUS\$ |
| Utility 1     | 400             | 5000          | 500           | 3000          | 1500          | 1900        |
| Utility 2     | 400             | 7500          | 500           | 3000          | 4000          | 4400        |
| Utility 3     | 800             | 7500          | 1000          | 4500          | 2000          | 2800        |
| Utility 4     | 400             | 5000          | 500           | 4000          | 500           | 900         |
| TOTAL         | 2000            | 25000         | 2500          | 14500         | 8000          | 10000       |
| Alternative B |                 |               |               |               |               |             |
| Compy         | ICBF<br>[MUS\$] | VB<br>[MUS\$] | CB<br>[MUS\$] | CP<br>[MUS\$] | Re<br>[MUS\$] | Bf<br>MUS\$ |
| Utility 1     | 500             | 5000          | 500           | 3000          | 1500          | 2000        |
| Utility 2     | 500             | 7500          | 500           | 3000          | 4000          | 4500        |
| Utility 3     | 1000            | 7500          | 1000          | 4500          | 2000          | 3000        |
| Utility 4     | 500             | 5000          | 500           | 4000          | 500           | 1000        |
| TOTAL         | 2500            | 25000         | 2500          | 14500         | 8000          | 10500       |
| Alternative C |                 |               |               |               |               |             |
| Compy         | ICBF<br>[MUS\$] | VB<br>[MUS\$] | CB<br>[MUS\$] | CP<br>[MUS\$] | Re<br>[MUS\$] | Bf<br>MUS\$ |
| Utility 1     | 600             | 5000          | 500           | 3000          | 1500          | 2100        |
| Utility 2     | 600             | 7500          | 500           | 3000          | 4000          | 4600        |
| Utility 3     | 1200            | 7500          | 1000          | 4500          | 2000          | 3200        |
| Utility 4     | 600             | 5000          | 500           | 4000          | 500           | 1100        |
| TOTAL         | 3000            | 25000         | 2500          | 14500         | 8000          | 11000       |
| Alternative D |                 |               |               |               |               |             |
| Compy         | ICBF<br>[MUS\$] | VB<br>[MUS\$] | CB<br>[MUS\$] | CP<br>[MUS\$] | Re<br>[MUS\$] | Bf<br>MUS\$ |
| Utility 1     | 300             | 5000          | 500           | 3000          | 1500          | 1800        |
| Utility 2     | 300             | 7500          | 500           | 3000          | 4000          | 4300        |
| Utility 3     | 600             | 7500          | 1000          | 4500          | 2000          | 2600        |
| Utility 4     | 300             | 5000          | 500           | 4000          | 500           | 800         |
| TOTAL         | 1500            | 25000         | 2500          | 14500         | 8000          | 9500        |
| Alternative E |                 |               |               |               |               |             |
| Compy         | ICBF<br>[MUS\$] | VB<br>[MUS\$] | CB<br>[MUS\$] | CP<br>[MUS\$] | Re<br>[MUS\$] | Bf<br>MUS\$ |
| Utility 1     | 200             | 5000          | 500           | 3000          | 1500          | 1700        |
| Utility 2     | 200             | 7500          | 500           | 3000          | 4000          | 4200        |
| Utility 3     | 400             | 7500          | 1000          | 4500          | 2000          | 2400        |
| Utility 4     | 200             | 5000          | 500           | 4000          | 500           | 700         |
| TOTAL         | 1000            | 25000         | 2500          | 14500         | 8000          | 9000        |

In this case all companies render a positive total income for all alternatives. In other words, PBC have little impact on the results of the companies, and they exhibit good performance in the PX because their marginal production costs are lower than the clearing price. Thus, this case is more stable than the two precedent cases.

**3.3. Industry Results**

It is possible to draw some conclusions regarding the performance of the production industry as a whole. In Table 5 the summary of total income balance (BF) for generators is presented for each case.

**Table 5. General industry results**

| % CBF | Alternative A<br>[MUS\$] | Alternative B<br>[MUS\$] | Alternative C<br>[MUS\$] | Alternative D<br>[MUS\$] | Alternative E<br>[MUS\$] |
|-------|--------------------------|--------------------------|--------------------------|--------------------------|--------------------------|
| 10    | 10000                    | 10500                    | 11000                    | 9500                     | 9000                     |
| 50    | 8000                     | 10500                    | 13000                    | 5500                     | 3000                     |
| 75    | 6750                     | 10500                    | 14250                    | 3000                     | -750                     |

From Table 5 we see that alternative B has no variation with respect to PBC, which is due to the equality between the clearing and PBC price.

Also, Table 5 shows extreme values when the PBC are 75% of the full load of the system. This means, that for this case it is possible to obtain the best and the worst results, depending on the efficiency of the generating units. Thus, for alternative C the highest results are achieved, whereas alternative E shows the lowest results.

On the other hand, when there is a 10% of PBC, all alternatives are similar. In other words, PBC has low impact on the results of companies and they will depend mostly on the difference between the clearing price and their production marginal cost. Thus, in this case the economical performance of companies depend almost entirely on  $P_x$ , as it was the California market. In this light, if PBC are a significant percentage of the contracted load, they can be seen as a convenient tool to stabilize  $P_x$  fluctuations.

There is also a risk involved in this operations, and some companies may experience a decrease in their income. This case occurs when there is an important percentage of PBC and the clearing price is high. In this condition, the income is decreased, as shown in Table 3 by Utilities 1, 3 and 4 for a price of PBC of 30 mills/kWh (Alternative E).

#### 4. STRATEGIC BIDDING

According to the economic theory, in a perfectly competitive market generating companies should bid very close to their marginal production costs to maximize returns [8], [11]. However, due to the fact that electricity market is not perfect (lack of elasticity in demand, low number of competitors, lack of energy storage, etc.), suppliers may elaborate their bids in a different way to seek a maximization of their benefit [9,10]. In this section, we study the effect of strategic bidding in the proposed market structure for the Chilean system.

##### 4.1 Base Case

In order to study the effect of strategic bidding we set up a base case (called case 0), where all participants bid with their marginal production costs. The demand is taken from the actual CIS demand as of April 20, 2001. The bidding for this case is shown in Table 6.

**Table 6. Marginal production costs bids**

| Company   | T1 |        | T2 |        | T3 |        | T4 |        |
|-----------|----|--------|----|--------|----|--------|----|--------|
|           | P1 | E1     | P2 | E2     | P3 | E3     | P4 | E4     |
| Utility 1 | 10 | 1000.0 | 30 | 3000.0 | 0  | 0.0    | 0  | 0.0    |
| Utility 2 | 5  | 276.3  | 14 | 959.0  | 20 | 1297.3 | 45 | 1469.5 |
| Utility 3 | 10 | 600.0  | 25 | 900.0  | 30 | 1067.0 | 0  | 0.0    |
| Utility 4 | 5  | 250.9  | 18 | 372.2  | 0  | 0.0    | 0  | 0.0    |

In Table 6, Utility 2 has four steps (T1 through T4) in its marginal cost curve, Utility 3 has three steps, and the other two utilities have only two steps. For each step, the price ( $P_i$ ) and the amount of energy ( $E_i$ ) are shown. The result of the auction in this base case is presented in Figure 2.

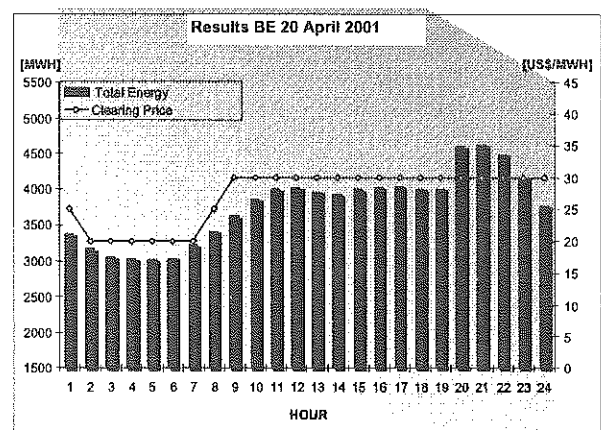


Figure 2. Clearing for day April 20, 2001

##### 4.2 Strategic Bidding in one Utility

Then, we let just one participant, in this case Utility 3, to change its bid in order to maximize its own profit. With these changes we construct ten different bids, as shown in Appendix A.

The economical results are shown in Table 7. In this table we can see that Utility 3 reaches its maximum income for Case 7, where it experiences a difference of MUS\$ 236,75 with respect to the base case (case 0).

Also, from Table 7 we can verify that the other companies experience an increment in their income. This is due to the fact that the clearing price is higher on average than the base case.

Tabla 7. Economical results

| Utility 1 |          |                        |                        |                        |            |                      |                        |
|-----------|----------|------------------------|------------------------|------------------------|------------|----------------------|------------------------|
| CA SE     | Engy GWh | V <sub>B</sub> [MUS\$] | C <sub>B</sub> [MUS\$] | C <sub>P</sub> [MUS\$] | Re [MUS\$] | B <sub>r</sub> MUS\$ | Diff. wrt Case 0 MUS\$ |
| 0         | 34,41    | 344,14                 | 202,08                 | 344,14                 | -202,08    | 302,92               | 0,00                   |
| 1         | 31,89    | 886,40                 | 547,08                 | 318,92                 | 20,40      | 525,40               | 222,48                 |
| 2         | 31,80    | 873,31                 | 538,67                 | 318,01                 | 16,64      | 521,64               | 218,72                 |
| 3         | 32,76    | 878,21                 | 518,47                 | 327,64                 | 32,10      | 537,10               | 234,18                 |
| 4         | 34,22    | 912,35                 | 511,73                 | 342,23                 | 58,39      | 563,39               | 260,47                 |
| 5         | 32,41    | 891,68                 | 538,67                 | 324,15                 | 28,86      | 533,86               | 230,94                 |
| 6         | 32,22    | 906,23                 | 555,50                 | 322,25                 | 28,48      | 533,48               | 230,56                 |
| 7         | 30,53    | 870,65                 | 568,13                 | 305,27                 | -2,74      | 502,26               | 199,34                 |
| 8         | 31,22    | 894,01                 | 570,65                 | 312,24                 | 11,12      | 516,12               | 213,20                 |
| 9         | 30,89    | 894,07                 | 580,75                 | 308,94                 | 4,38       | 509,38               | 206,46                 |
| 10        | 30,84    | 882,31                 | 572,33                 | 308,38                 | 1,60       | 506,60               | 203,68                 |
| Utility 2 |          |                        |                        |                        |            |                      |                        |
| CA SE     | Engy GWh | V <sub>B</sub> [MUS\$] | C <sub>B</sub> [MUS\$] | C <sub>P</sub> [MUS\$] | Re [MUS\$] | B <sub>r</sub> MUS\$ | Diff. wrt Case 0 MUS\$ |
| 0         | 35,26    | 352,56                 | 135,12                 | 176,28                 | 41,16      | 378,66               | 0,00                   |
| 1         | 29,72    | 811,89                 | 365,63                 | 148,60                 | 297,66     | 635,16               | 256,50                 |
| 2         | 29,10    | 786,75                 | 360,00                 | 145,51                 | 281,23     | 618,73               | 240,07                 |
| 3         | 28,35    | 748,76                 | 346,50                 | 141,77                 | 260,48     | 597,98               | 219,32                 |
| 4         | 27,78    | 732,33                 | 342,00                 | 138,88                 | 251,45     | 588,95               | 210,29                 |
| 5         | 28,95    | 783,69                 | 360,00                 | 144,75                 | 278,94     | 616,44               | 237,78                 |
| 6         | 29,27    | 815,60                 | 371,25                 | 146,33                 | 298,02     | 635,52               | 256,86                 |
| 7         | 30,46    | 858,62                 | 379,69                 | 152,29                 | 326,64     | 664,14               | 285,48                 |
| 8         | 29,92    | 854,01                 | 381,38                 | 149,62                 | 323,02     | 660,52               | 281,86                 |
| 9         | 30,70    | 882,72                 | 388,13                 | 153,52                 | 341,08     | 678,58               | 299,92                 |
| 10        | 30,61    | 868,10                 | 382,50                 | 153,06                 | 332,54     | 670,04               | 291,38                 |
| Utility 3 |          |                        |                        |                        |            |                      |                        |
| CA SE     | Engy GWh | V <sub>B</sub> [MUS\$] | C <sub>B</sub> [MUS\$] | C <sub>P</sub> [MUS\$] | Re [MUS\$] | B <sub>r</sub> MUS\$ | Diff. wrt Case 0 MUS\$ |
| 0         | 12,12    | 121,20                 | 81,12                  | 121,20                 | -81,12     | 121,38               | 0,00                   |
| 1         | 20,12    | 560,17                 | 219,38                 | 201,20                 | 139,60     | 342,10               | 220,72                 |
| 2         | 20,74    | 565,09                 | 216,00                 | 207,37                 | 141,72     | 344,22               | 222,84                 |
| 3         | 20,95    | 538,25                 | 207,90                 | 209,48                 | 120,86     | 323,36               | 201,98                 |
| 4         | 20,17    | 497,21                 | 205,20                 | 201,68                 | 90,33      | 292,83               | 171,45                 |
| 5         | 20,19    | 547,16                 | 216,00                 | 201,90                 | 129,26     | 331,76               | 210,38                 |
| 6         | 20,18    | 564,85                 | 222,75                 | 201,80                 | 140,31     | 342,81               | 221,43                 |
| 7         | 20,19    | 585,34                 | 227,81                 | 201,91                 | 155,63     | 358,13               | 236,75                 |
| 8         | 20,16    | 567,73                 | 228,83                 | 201,62                 | 137,28     | 339,78               | 218,40                 |
| 9         | 20,11    | 588,20                 | 232,88                 | 201,11                 | 154,21     | 356,71               | 235,33                 |
| 10        | 20,19    | 582,44                 | 229,50                 | 201,91                 | 151,03     | 353,53               | 232,15                 |
| Utility 4 |          |                        |                        |                        |            |                      |                        |
| CA SE     | Engy GWh | V <sub>B</sub> [MUS\$] | C <sub>B</sub> [MUS\$] | C <sub>P</sub> [MUS\$] | Re [MUS\$] | B <sub>r</sub> MUS\$ | Diff. wrt Case 0 MUS\$ |
| 0         | 8,93     | 89,33                  | 34,08                  | 44,66                  | 10,58      | 95,58                | 0,00                   |
| 1         | 8,93     | 241,93                 | 92,08                  | 44,66                  | 105,18     | 190,18               | 94,60                  |
| 2         | 8,93     | 238,21                 | 90,67                  | 44,66                  | 102,88     | 187,88               | 92,29                  |
| 3         | 8,37     | 220,64                 | 87,27                  | 41,86                  | 91,51      | 176,51               | 80,93                  |
| 4         | 8,21     | 215,77                 | 86,13                  | 41,07                  | 88,57      | 173,57               | 77,99                  |
| 5         | 8,93     | 238,21                 | 90,67                  | 44,66                  | 102,88     | 187,88               | 92,29                  |
| 6         | 8,93     | 245,65                 | 93,50                  | 44,66                  | 107,49     | 192,49               | 96,90                  |
| 7         | 8,93     | 251,24                 | 95,63                  | 44,66                  | 110,95     | 195,95               | 100,36                 |
| 8         | 8,80     | 250,29                 | 96,05                  | 43,99                  | 110,25     | 195,25               | 99,67                  |
| 9         | 8,93     | 256,82                 | 97,75                  | 44,66                  | 114,40     | 199,40               | 103,82                 |
| 10        | 8,93     | 253,10                 | 96,33                  | 44,66                  | 112,10     | 197,10               | 101,51                 |

### 4.3 Comments

This exercise shows that strategic bidding is a very profitable mechanism for generating companies, which can access to a significant increase in their income. This can be done by using a bidding strategy different from the marginal production cost. For this reason, the proposed Px structure in Chile enforces companies to submit bidding according to its marginal production costs [14].

There is a discussion under way regarding the hydro power plants with reservoir. Some of them may store energy and transfer it between consecutive years. The important question here is how to compute the marginal production cost of that plants. Thus, this is a key point for the performance of the proposed Px.

## 5. CONCLUSIONS

In this paper a structural study of a proposed market power exchange for the Chilean market has been presented. The study is based on a test case, where real information from the agents of the system is used.

Results show the following:

- Physical bilateral contracts are a key element for stabilizing the electric market, which otherwise will experience fluctuations as the Px varies according to the bidding agenda of each participant.
- There is a trade off between the percentage of PBC and the risk in the PX. In the test cases studied, when PBC represent 50% or less of the total load, the income of generating companies is stabilized. When this percentage is over 75% there is a major risk, which can lead to great increase of losses in the company's income.
- Strategic bidding can give important revenues to generating companies. This leads to an increase in the clearing price on average.

All the above elements are currently under study in order to improve the proposed market structure in Chile.

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## APENDIX A.

Strategic bidding is set up as a piece wise linear function with four steps. In Table 8 the biddings of Utility 3 are presented. All other competitors maintain their bids.

**Table 8. Strategic Bidding**

| Caso 2    | T1 |     | T2 |          | T3 |      |
|-----------|----|-----|----|----------|----|------|
|           | P1 | E1  | P2 | E2       | P3 | E3   |
| Hora 1-8  | 8  | 600 | 20 | 900      | 25 | 1067 |
| Hora 9-24 | 12 | 600 | 25 | 900      | 30 | 1067 |
| Caso 3    | T1 |     | T2 |          | T3 |      |
|           | P1 | E1  | P2 | E2       | P3 | E3   |
| Hora 1-8  | 8  | 600 | 15 | 900      | 20 | 1067 |
| Hora 9-19 | 15 | 600 | 25 | 900      | 30 | 1067 |
| Hra 20-24 | 15 | 600 | 30 | 900      | 35 | 1067 |
| Caso 4    | T1 |     | T2 |          | T3 |      |
|           | P1 | E1  | P2 | E2       | P3 | E3   |
| Hora 1-8  | 5  | 600 | 14 | 100<br>0 | 20 | 1067 |
| Hora 9-19 | 15 | 600 | 25 | 700      | 30 | 1067 |
| Hra 20-24 | 15 | 600 | 30 | 900      | 35 | 1067 |
| Caso 5    | T1 |     | T2 |          | T3 |      |
|           | P1 | E1  | P2 | E2       | P3 | E3   |
| Hora 1    | 10 | 600 | 15 | 900      | 30 | 1067 |
| Hora 2-7  | 10 | 600 | 20 | 900      | 30 | 1067 |
| Hora 8    | 10 | 600 | 15 | 900      | 30 | 1067 |
| Hora 9    | 10 | 600 | 25 | 900      | 40 | 1067 |
| Hra 10-16 | 10 | 600 | 25 | 700      | 40 | 1067 |
| Hra 16-23 | 10 | 600 | 20 | 900      | 25 | 1067 |
| Caso 6    | T1 |     | T2 |          | T3 |      |
|           | P1 | E1  | P2 | E2       | P3 | E3   |
| Hora 1    | 10 | 600 | 15 | 650      | 30 | 1067 |
| Hora 2-7  | 10 | 600 | 20 | 900      | 30 | 1067 |
| Hora 8    | 10 | 600 | 15 | 700      | 30 | 1067 |
| Hora 9    | 15 | 600 | 25 | 650      | 40 | 1067 |
| Hra 10-16 | 15 | 600 | 20 | 700      | 30 | 1067 |
| Hra 16-23 | 10 | 600 | 20 | 900      | 25 | 1067 |
| Caso 7    | T1 |     | T2 |          | T3 |      |
|           | P1 | E1  | P2 | E2       | P3 | E3   |
| Hora 1    | 30 | 600 | 35 | 700      | 40 | 1067 |
| Hora 2    | 25 | 600 | 15 | 900      | 40 | 1067 |
| Hora 3-9  | 20 | 550 | 15 | 900      | 25 | 1067 |
| Hra 10-24 | 10 | 600 | 20 | 900      | 25 | 1067 |
| Caso 8    | T1 |     | T2 |          | T3 |      |
|           | P1 | E1  | P2 | E2       | P3 | E3   |
| Hora 1-5  | 30 | 600 | 35 | 700      | 40 | 1067 |
| Hora 6    | 10 | 600 | 15 | 900      | 40 | 1067 |
| Hora 7-9  | 10 | 600 | 15 | 900      | 25 | 1067 |
| Hra 10-24 | 10 | 600 | 20 | 900      | 25 | 1067 |
| Caso 9    | T1 |     | T2 |          | T3 |      |
|           | P1 | E1  | P2 | E2       | P3 | E3   |
| Hora 1    | 10 | 600 | 20 | 700      | 40 | 1067 |
| Hora 2-5  | 25 | 600 | 28 | 650      | 40 | 1067 |
| Hora 6    | 25 | 500 | 30 | 700      | 35 | 1067 |
| Hora 7-8  | 30 | 800 | 33 | 900      | 35 | 1067 |
| Hora 9-24 | 10 | 600 | 20 | 900      | 25 | 1067 |
| Caso 10   | T1 |     | T2 |          | T3 |      |
|           | P1 | E1  | P2 | E2       | P3 | E3   |
| Hora 1    | 10 | 600 | 20 | 900      | 40 | 1067 |
| Hora 2-5  | 25 | 600 | 28 | 650      | 40 | 1067 |
| Hora 6    | 25 | 500 | 30 | 700      | 35 | 1067 |
| Hora 7-8  | 30 | 800 | 33 | 900      | 35 | 1067 |
| Hora 9-24 | 10 | 600 | 20 | 900      | 25 | 1067 |

## Discussions on Session III: MARKETS

### Part 2

**C. Vournas:** I was very interested by parts of the paper by C. Canizares. There are a few concerns I have that would be better understood when I present my paper on Thursday concerning inequality constraints and how to compute the sensitivity on the limit due to generator switching. So I will leave this part. I have another question for Claudio. It seems that at your solution, if the margin to collapse is not enough, you shed load, which is a little bit premature. I mean in not many actual applications you would shed load just because the margin is not enough; you would wait until you really have an emergency to shed load. So I would like it, if you can comment on that.

**C. Canizares:** Certainly. What we're dealing here is we are not really shedding load in terms of physically doing it. Because it is the market that we're looking ahead, and saying, well, this is the bidding process. What we're trying to do first is try to reschedule our generators as early as we can, before we actually account for the load, in other words, accounting for the factor. We could shed load, because at least the load is elastic. They're getting into the competition, and they are willing to be supplied or not. So for security reason, you are not supplied, fine. In the case of inelastic loads, which we also look at, it is that if the load getting into the market, the price of not supplying the load would be very high, so that would increase significantly the cost, and it wouldn't be an option, right? But physically we are not really shedding load, we're assumed that the load has been supplied, and we're looking ahead to the bidding process. I hope that answers your question.

**F. Wu (Hong Kong University):** I have one comment and two questions for Sandro. The first comment, you seemed to respond to Costas's comment earlier to view reactive power as a service, and separate the component for generators needed to support its own voltage, and another component to provide service for the voltage support in the system. You seemed to propose a way to do that. The two questions, first, you're doing this for the supply side for the generators. Is it possible to do that for the demand side? Can you do that for the demand side separating the reactive power consumed because of the load demand, and also the load may contribute to the reactive power to the system. Can you do the same way on the demand side? The second question, do you anticipate if we operate this in the market situation rather than after the fact calculation? Before the fact you have a market for reactive power, and the participants can bid their price from both supply and demand. How this system can work, can you comment on that?

**S. Corsi:** About the first question, my view is to separate the aspect of demand in comparison with a given demand what is the unit participation to the voltage support. Because if I look at the Italian situation just to give you an idea, the changes over their active power generator to support the voltage is very uncommon, it would be a very particular situation. It could be possible to use some congestion, you can never in particular situation, except some point, which could be that the dispatcher ever to ask to move something there. But you know, my proposal is that if you want, according to their original access, the other is, I want to say that you can both consider the changes in reactive power requirement to the power plant in a certain way from economical contract. The other, you have to combine the two in the case there are some special requirements about the changes of the reactive power at a given generator to the voltage support. I don't know if this is correct.

**P. A. Lof (ABB):** I have a question concerning the new market regulation in Chile. It looks interesting and promising but how much must the generator units participate in a power exchange to have market power? Have you done any study on that? How much of the generator units must participate in the power change to avoid the market power to take over?

**L. Vargas:** They are enforced to freely submit their full capacity. All of the generating units must submit a bid with price and energy, and the energy must be exactly the full capacity of the generating unit. We didn't study how many of them.

**Chairman (P. Sauer):** Ok, I have to terminate. Let's give our authors another hand.

**Session IV:**  
**TRANSACTION EVALUATION &**  
**CONGESTION MANAGEMENT**

Tuesday, August 28, 17:00–20:00

Chair: Jong-Keun Park

## Congestion Management Allocation In Multiple Transaction Networks

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**Abstracts:** We present a physical-flow-based congestion management allocation mechanism for multiple-transaction networks in this paper. We use the multiple transaction network framework constructed in [1] to characterize transmission congestion and then determine the contribution to congestion attributable to each transaction on a physical-flow basis. We present an adjustment auction-based congestion relief mechanism that enables the IGO to acquire relief services to remove the overload congestion attributed to each transaction from the network in the most economic manner. This congestion relief scheme determines the appropriate transmission charges for each transaction's usage of the network. We illustrate the workings of the proposed scheme using the IEEE 30-bus and 57-bus systems and discuss the important policy implications of the congestion allocation and relief solution.

### 1. INTRODUCTION

The open access transmission regime plays the central role of the rapid disintegration of the well-entrenched vertically integrated structure of the electric industry. This regime has resulted in the entry of a large number of new players and the proliferation of transactions. In the new competitive electricity market environment, the transmission system takes on a *common carrier* role. These changes are bringing about the establishment of an independent grid operator (IGO) such as the various Independent System Operator and Regional Transmission Organizations (RTO) entities in existence or formulation. One of the IGO's key functions is congestion management [2].

Congestion occurs whenever the transmission network is unable to accommodate all the desired transactions due to the violation of one or more constraints for the resulting state under the set of specified contingencies. The open access transmission regime results in the more intensive use of the transmission system, which, in turn, leads to more frequent congestion. The task of congestion management requires the IGO to identify and relieve such situations through the development of various physical or financial mechanisms. Since the scope of these congestion management activities includes the determination of the actual

transmission usage by the individual transactions, the IGO has significant financial impacts on each market participant. A basic requirement is that the congestion management and pricing must be nondiscriminatory and transparent.

Various congestion management schemes for the different restructuring paradigms have appeared in the literature. Hogan proposed the contract network and nodal pricing approach [3] using the spot pricing theory [4] for the so-called *Poolco* paradigm. In the nodal pricing approach, congestion management is performed through a *centralized* optimal dispatch, while transmission charges are determined *ex post* and set to the nodal spot price differences. Chao and Peck proposed in [5] an alternative which is based on parallel markets for link-based transmission capacity rights and energy trading under a set of rules defined and administrated by the IGO. These rules specify the transmission capacity rights required to support any bilateral transactions and are adjusted continuously to reflect changing system conditions. In the so-called *coordinated multilateral trade* framework developed by Wu and Varaiya [6], economic decisions are carried out through multilateral trades and the reliability function is coordinated by the IGO who provides publicly accessible data for generators and consumers to use in determining feasible and profitable trades. An attractive property of the formulation is that any sequence of such coordinated private multilateral trades leads to efficient operations maximizing social welfare. The two schemes [5][6] have in common the reliance on decentralized decision making and market forces. However, their implementation would require the availability of a highly sophisticated market and of advanced information technology.

Several optimal power flow (OPF)-based congestion management schemes for multiple transaction systems have been proposed. An approach to relieving congestion using the minimum total modification to the desired transactions was presented in [7]. A variant of this least modification approach [8] used a

weighting scheme with the weights being the surcharges paid by the transactions for transmission usage in the congestion-relieved network. The congestion management scheme for the California ISO [9] aims to relieve the network of interzonal congestion using the adjustment offers of the scheduling coordinators<sup>1</sup>. The congestion relief objective is to maximize the value of the limited transfer capability measured by the offers. Every entity scheduling flow on a congested path is charged the transmission usage charge for its flow on the congested line. Transmission usage charges are specified by the shadow price of the problem formulation. An important feature of this scheme is the enforcement of the *separation of markets* constraint to ensure that the IGO does not create new transactions that the scheduling coordinators did not initiate on their own. A similar adjustment-auction-based scheme [10] differs from that of [9] in that the *separation of the markets* constraint on each scheduling coordinator is not introduced.

In this paper, we develop a physical-flow-based congestion management allocation scheme to determine the contribution to the overload congestion attributed to each transaction. In fact, congestion allocation among transactions is a heretofore unsolved problem. The contribution of the paper is that it presents a physically reasonable scheme to appropriately allocate congestion among multiple transactions. The congestion relief scheme provides the IGO with an effective tool with which the IGO acquires the congestion relief services to remove each transaction's congestion contribution at least cost. The proposed scheme is general and can accommodate different market rule specifications. The scheme permits each transaction to make its own transmission usage decisions and provides the transaction with efficient price signals for this task. The paper consists of three additional sections. Section 2 focuses on the development of an allocation mechanism to determine the allocation attributed to each transaction of its contribution to the network congestion. Section 3 formulates the IGO's least-cost congestion relief problem. We present the optimality analysis and develop the transmission usage pricing scheme. Section 4 is devoted to the presentation of numerical results

and some discussions of the key policy implication of the mechanism developed.

We focus on the congestion issue for the forward markets such as the next day or the next hour markets. In such cases the analysis is done on an hourly basis. Note that congestion may occur due to the onset of a contingency in the real-time operation of the power system. However, the real-time congestion relief is outside the scope of the paper. The long-term solution to congestion through the transmission system expansion is also not addressed here.

## 2. CONGESTION ALLOCATION

We use the definition of a bilateral real power transaction and the multiple-transaction framework explicitly recasting the power flow problem in terms of all the transactions on the system that we developed in [1]. We consider a system of  $N+1$  buses with the swing bus at bus 0 and the set  $\mathcal{M}$  of transactions. A bilateral transaction  $m \in \mathcal{M}$  is a set of selling buses (injection buses)  $\mathcal{S}^{(m)}$  supplying a specified amount of real power  $t^{(m)}$  to a set of buying buses (withdrawal buses)  $\mathcal{B}^{(m)}$ :

$$\mathcal{T}^{(m)} = \{t^{(m)}, \mathcal{S}^{(m)}, \mathcal{B}^{(m)}\}. \quad (1)$$

In this triplet, the set  $\mathcal{S}^{(m)}$  is the collection of 2-tuples

$$\mathcal{S}^{(m)} = \{(s_i^{(m)}, \sigma_i^{(m)}), i = 1, 2, \dots, N_s^{(m)}\}, \quad (2)$$

with the selling bus  $s_i^{(m)}$  supplying  $\sigma_i^{(m)} t^{(m)}$  MW of the transaction amount. The fractions

$$\sigma_i^{(m)} \text{ must satisfy the conditions } \sum_{i=1}^{N_s^{(m)}} \sigma_i^{(m)} = 1$$

with  $\sigma_i^{(m)} \in [0, 1]$ ,  $i = 1, 2, \dots, N_s^{(m)}$ , where  $N_s^{(m)}$  is the number of selling buses in transaction  $m$ .

Similarly,  $\mathcal{B}^{(m)}$  is the collection of 2-tuples

$$\mathcal{B}^{(m)} = \{(b_j^{(m)}, \beta_j^{(m)}), j = 1, 2, \dots, N_b^{(m)}\}, \quad (3)$$

where the buying bus  $b_j^{(m)}$  receives  $\beta_j^{(m)} t^{(m)}$  MW of the transaction amount. The fraction

$$\beta_j^{(m)} \text{ must satisfy the conditions } \sum_{j=1}^{N_b^{(m)}} \beta_j^{(m)} = 1$$

with  $\beta_j^{(m)} \in [0, 1]$ ,  $j = 1, 2, \dots, N_b^{(m)}$ , where  $N_b^{(m)}$  is the number of buying buses in transaction  $m$ .

<sup>1</sup> Note that in this paper conceptually, a scheduling coordinator and a transaction are synonymous entities.

We characterize transmission congestion within this framework and then determine the contribution to congestion attributable to each transaction. We denote by  $\mathcal{L}$  the set of transmission lines. We refer to the flows that result from these proposed transactions as the *preferred schedule* flows and denote by  $f_\ell$  the real power flow in line  $\ell \in \mathcal{L}$ . We adopt the convention that  $f_\ell \geq 0$  so that the flow from the *from* bus to the *to* bus is always nonnegative. We simplify the representation of the various transmission constraints and model them in terms of line flow limits: each line  $\ell$  has the flow limit  $f_\ell^{\max}$ . In this model, congestion corresponds to the overloading of one or more transmission lines in the preferred schedule flows. Let  $\tilde{\mathcal{L}} \subset \mathcal{L}$  be the subset of overloaded lines, i.e.,

$$\tilde{\mathcal{L}} \triangleq \{ \ell \in \mathcal{L} : f_\ell > f_\ell^{\max} \} \quad (4)$$

and let  $\Delta f_\ell$  denote the overload in line  $\ell \in \tilde{\mathcal{L}}$ :

$$\Delta f_\ell \triangleq f_\ell - f_\ell^{\max}. \quad (5)$$

Consider the overloaded line  $\ell \in \tilde{\mathcal{L}}$ . We represent  $\Delta f_\ell$  in terms of the proposed transactions. Let line  $\ell$  join buses  $i$  and  $j$ . We assume that the effects of the shunt elements on the real power line flow are negligible and so the line is represented by its line impedance  $r_{ij} + jx_{ij}$ . We define  $g_{ij} \triangleq r_{ij} / (r_{ij}^2 + x_{ij}^2)$  and  $b_{ij} \triangleq x_{ij} / (r_{ij}^2 + x_{ij}^2)$ . The voltage magnitude  $V_n$  and angle  $\theta_n$  for buses  $n=1,2,\dots,N$  are a function of  $\mathcal{M}$  [13]. Then, the line flow  $f_\ell$  from bus  $i$  to bus  $j$  is given by

$$f_\ell = g_{ij}[V_i^2 - V_i V_j \cos(\theta_i - \theta_j)] + b_{ij}[V_i V_j \sin(\theta_i - \theta_j)]. \quad (6)$$

Under the assumption that the DC power flow conditions hold, we may approximate  $f_\ell$

$$\tilde{f}_\ell = [g_{ij}(\theta_i - \theta_j) / 2 + b_{ij}](\theta_i - \theta_j), \quad (7)$$

Next, we define  $\hat{\theta} = [\hat{\theta}_1, \hat{\theta}_2, \dots, \hat{\theta}_N]^T$  as the voltage angle vector computed by the DC power flow. Without any loss of generality, we may set to 0 the value of  $\hat{\theta}_0$  at the slack bus. Then,

$$\hat{\theta}_i - \hat{\theta}_j = \sum_{m \in \mathcal{M}} \pi_{ij}^{(m)} t^{(m)}, \quad i, j = 0, 1, 2, \dots, N, i \neq j, \quad (8)$$

with the definition of  $\pi_{ij}^{(m)}$  and the derivation of (8) given in Appendix A. In order to express the approximation of the line flow in terms of the

proposed transactions, we further approximate  $\tilde{f}_\ell$  in (7) by

$$\begin{aligned} \hat{f}_\ell &= [g_{ij}(\theta_i - \theta_j) / 2 + b_{ij}](\hat{\theta}_i - \hat{\theta}_j) \\ &= [g_{ij}(\theta_i - \theta_j) / 2 + b_{ij}] \sum_{m \in \mathcal{M}} \pi_{ij}^{(m)} t^{(m)} \\ &= \sum_{m \in \mathcal{M}} \{ [g_{ij}(\theta_i - \theta_j) / 2 + b_{ij}] \pi_{ij}^{(m)} \} t^{(m)}. \end{aligned} \quad (9)$$

If we define for each  $m \in \mathcal{M}$

$$\varphi_\ell^{(m)} \triangleq [g_{ij}(\theta_i - \theta_j) / 2 + b_{ij}] \pi_{ij}^{(m)} \quad (10)$$

then<sup>2</sup>,

$$\hat{f}_\ell = \sum_{m \in \mathcal{M}} \varphi_\ell^{(m)} t^{(m)}. \quad (11)$$

In (11), we may consider  $\varphi_\ell^{(m)} t^{(m)}$  to be the flow attributable to transaction  $m$  in the preferred schedule with the sign of  $\varphi_\ell^{(m)}$  indicating the direction of the contribution to the flow  $f_\ell$  associated with transaction  $m$ . For each overloaded line  $\ell$ , we partition  $\mathcal{M}$  into two non-intersecting subsets  $\mathcal{D}_\ell$  and  $\mathcal{C}_\ell$ :

$$\mathcal{D}_\ell \triangleq \{ m \in \mathcal{M} : \varphi_\ell^{(m)} \geq 0 \}, \quad \mathcal{C}_\ell \triangleq \{ m \in \mathcal{M} : \varphi_\ell^{(m)} < 0 \} \quad (12)$$

Thus,  $\mathcal{D}_\ell$  is the subset of the transactions whose associated flows are in the same direction as the net flow  $f_\ell$ . We call such a flow a *dominant flow*. Conversely,  $\mathcal{C}_\ell$  is the subset of transactions, if any, whose associated flows are in the opposite direction to  $f_\ell$ . We call such a flow a *counter flow*. It follows from (5), (11) and (12) that the overload  $\Delta f_\ell$  may be approximated by

$$\begin{aligned} \Delta \tilde{f}_\ell &= \sum_{m \in \mathcal{M}} \varphi_\ell^{(m)} t^{(m)} - f_\ell^{\max} \\ &= \sum_{m \in \mathcal{D}_\ell} \varphi_\ell^{(m)} t^{(m)} - \left\{ f_\ell^{\max} + \left[ - \sum_{m \in \mathcal{C}_\ell} \varphi_\ell^{(m)} t^{(m)} \right] \right\} \end{aligned} \quad (13)$$

Since each transaction in  $\mathcal{D}_\ell$  results in dominant flows on the overloaded line  $\ell$ , these flows contribute to the overload in  $\ell$ . On the other hand, each transaction in  $\mathcal{C}_\ell$  results in counter flows and the flows, in effect, increase the line

<sup>2</sup> Note that if we assume that  $r_{ij} \ll x_{ij}$  and that  $|\theta_i - \theta_j|$  is small, then  $g_{ij}|\theta_i - \theta_j|/2 \ll b_{ij} \approx 1/x_{ij}$ . Consequently,  $\varphi_\ell^{(m)} \approx \pi_{ij}^{(m)}/x_{ij}$  so that the approximation in (11) is relatively straightforward to compute.

flow limit from  $f_\ell^{\max}$  to  $f_\ell^{\max} + [\sum_{m \in \mathcal{C}_\ell} -\varphi_\ell^{(m)} t^{(m)}]$ . So the line  $\ell$  overload is attributed in its entirety to the transactions in  $\mathcal{D}_\ell$ .

We define for each transaction  $m \in \mathcal{M}$   $\tilde{\mathcal{L}}^{(m)} \triangleq \{\ell : \ell \in \tilde{\mathcal{L}} \text{ and } \varphi_\ell^{(m)} \geq 0\}$ , (14) the subset of overloaded lines with the associated flows that contribute to the dominant flows in the lines. Note that for a given  $m$ ,  $\tilde{\mathcal{L}}^{(m)}$  may be empty. Let  $\hat{\mathcal{M}} = \bigcup_{\ell \in \tilde{\mathcal{L}}} \mathcal{D}_\ell$ . Then  $\hat{\mathcal{M}} \subset \mathcal{M}$  is the

subset of those transactions that contribute to the overloads in one or more lines. If, in addition, we assume that the line overload  $\Delta f_\ell$  is contributed *uniformly* by each transaction in  $\mathcal{D}_\ell$ , then the contribution to the total overload  $\Delta f_\ell$  attributable to transaction  $m \in \mathcal{D}_\ell$  is

$$\Delta f_\ell^{(m)} = \frac{\varphi_\ell^{(m)} t^{(m)}}{\sum_{m' \in \mathcal{D}_\ell} \varphi_\ell^{(m')} t^{(m')}} \Delta f_\ell = \frac{\varphi_\ell^{(m)} t^{(m)}}{\sum_{m' \in \mathcal{D}_\ell} \varphi_\ell^{(m')} t^{(m')}} \tilde{\Delta f}_\ell \quad (15)$$

We use the approximation in (15) as the basis for the congestion relief actions.

### 3. CONGESTION RELIEF

To determine the actions to remove congestion, we assume that the only congestion relief means available to the IGO are the acquisition of incremental/decremental injections into the system nodes from every willing participant, be it a generating or a load entity. To do so, the IGO runs an auction of incremental/decremental adjustments to select the most economic means to provide overload relief. We note that the participants in the adjustment auction need not be limited to be participants in the proposed transactions.

Let  $\mathcal{K}$  be the set of buses where the auction participants are located. The bidder at bus  $k$  submits an offer with the \$/MW price for the net injection adjustment  $\Delta p_k$ . Note that while a generator may provide  $\Delta p_k$  by increasing or decreasing its production output, a load may also effectively offer  $\Delta p_k$  by varying its demand by  $-\Delta p_k$ . The incremental injection  $\Delta p_k > 0$  (decremental injection  $\Delta p_k < 0$ ) offer has a

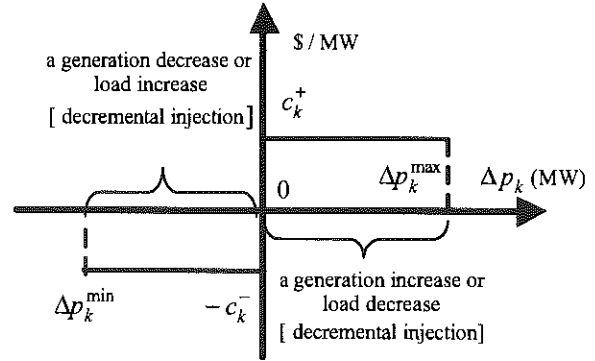


Figure 1. The offer of the bidder at bus  $k$

charge of  $c_k^+$  \$/MW (a rebate of  $c_k^-$  \$/MW)<sup>3</sup>. In its offer, the bidder also specifies the lower and upper limits within which it is physically capable and/or willing to provide its injection adjustment  $\Delta p_k \in [\Delta p_k^{\min}, \Delta p_k^{\max}]$ . If the IGO accepts the offer of the participant at bus  $k$ , then it pays  $c_k^+ \Delta p_k$  for  $\Delta p_k \geq 0$  to, or receives  $-c_k^- \Delta p_k$  for  $\Delta p_k < 0$  from, the bidder. The payment by the IGO for the bidder at bus  $k$  is illustrated in Figure 1. The IGO uses the offers submitted by the generators and the loads to determine the most economic congestion relief by minimizing the total costs incurred<sup>4</sup>. The decision variables for the IGO are the relief actions  $\Delta p_k^{(m)}$ ,  $k \in \mathcal{K}$ ,  $m \in \hat{\mathcal{M}}$ .  $\Delta p_k^{(m)}$  is the net incremental/decremental injection acquired from the bidder at bus  $k$  for transaction  $m$  to relieve the overload burden  $\Delta f_\ell^{(m)}$ ,  $\ell \in \tilde{\mathcal{L}}^{(m)}$  attributed to the transaction  $m$ . The IGO's objective function is to

$$\min Z = \sum_{k \in \mathcal{K}} c_k \left[ \sum_{m \in \hat{\mathcal{M}}} \Delta p_k^{(m)} \right] \quad (16)$$

where

$$c_k = \begin{cases} c_k^+ & \text{if } \Delta p_k = \sum_{m \in \hat{\mathcal{M}}} \Delta p_k^{(m)} \geq 0 \\ c_k^- & \text{otherwise} \end{cases} \quad (17)$$

We use a small signal model to analyze the effects on the transmission network of

<sup>3</sup> We assume that the participants in the auction are rational bidders so that at bus  $k$ ,  $c_k^- \leq c_k^+$ .

<sup>4</sup> While a uniform price auction is typically used in the forward energy markets, the adjustment auction for the transmission market is a pay-as-bid auction.

$\Delta p_k^{(m)}$ ,  $k \in \mathcal{K}$ ,  $m \in \hat{\mathcal{M}}$ . This is reasonable because  $\Delta p_k^{(m)}$  are typically small changes in the net injections at the buses  $k \in \mathcal{K}$  compared to the injection levels for the proposed transactions. We use the sensitivities  $\partial f_\ell / \partial p_k$  of the line flow  $f_\ell$  with respect to the net injection  $p_k$  at bus  $k$  to study the changes in the line flows in response to  $\Delta p_k^{(m)}$ . From the approximation  $\tilde{f}_\ell$  of  $f_\ell$  in (7), we obtain

$$\frac{\partial f_\ell}{\partial p_k} \approx \frac{\partial \tilde{f}_\ell}{\partial p_k} = [g_{ij}(\theta_i - \theta_j) + b_{ij}] \left( \frac{\partial \theta_i}{\partial p_k} - \frac{\partial \theta_j}{\partial p_k} \right) \approx [g_{ij}(\theta_i - \theta_j) + b_{ij}] \left( \frac{\partial \hat{\theta}_i}{\partial p_k} - \frac{\partial \hat{\theta}_j}{\partial p_k} \right) \quad (18)$$

It follows from (A8) in Appendix A that

$$\frac{\partial \hat{\theta}_i}{\partial p_k} - \frac{\partial \hat{\theta}_j}{\partial p_k} = d_{kj} - d_{ki} \quad (19)$$

The definitions of  $d_{ij}$ ,  $i, j = 0, 1, 2, \dots, N$  are the elements of  $\underline{D} = [\underline{B}]^{-1}$  the inverse of the DC power flow matrix in [11]. We define

$$\psi_{\ell,k} \triangleq [g_{ij}(\theta_i - \theta_j) + b_{ij}](d_{kj} - d_{ki}) \quad (20)$$

Since  $\psi_{\ell,k} \approx \frac{\partial f_\ell}{\partial p_k}$ ,  $\psi_{\ell,k}$  provides the expression for the approximation to the rate of the change in the line flow  $f_\ell$  with respect to the change in the net injection at bus  $k$ .

The constraints the IGO congestion relief actions need to satisfy are the followings:

(i) *power balance*:

$$\sum_{k \in \mathcal{K}} \sum_{m \in \hat{\mathcal{M}}} \Delta p_k^{(m)} = 0 \quad (21)$$

(ii) *removal of overloads*:

$$-\sum_{k \in \mathcal{K}} \psi_{\ell,k} \Delta p_k^{(m)} = \Delta f_\ell^{(m)}, \ell \in \tilde{\mathcal{L}}^{(m)}, m \in \hat{\mathcal{M}} \quad (22)$$

(iii) *no overloads in the IGO schedule*:

$$f_\ell + \sum_{k \in \mathcal{K}} \psi_{\ell,k} \Delta p_k \leq f_\ell^{\max}, \ell \in \mathcal{L} \quad (23)$$

(iii) *increment/decrement limits*:

$$\Delta p_k^{\min} \leq \Delta p_k^{(m)} \leq \Delta p_k^{\max}, k \in \mathcal{K} \quad (24)$$

(iv) *total increment/decrement limits*:

$$\Delta p_k^{\min} \leq \Delta p_k \leq \Delta p_k^{\max}, k \in \mathcal{K}, m \in \hat{\mathcal{M}} \quad (25)$$

(vi) *separation of markets*:

$$\sum_{k \in \mathcal{S}^{(m)} \cup \mathcal{O}^{(m)}} \Delta p_k = 0, m \in \hat{\mathcal{M}} \quad (26)$$

The equality constraints in (22) indicate that the IGO acquires the relief actions from the participants in the adjustment bidding to reduce the flow in line  $\ell$  by exactly the  $\Delta f_\ell^{(m)}$  overload attributed to transaction  $m \in \mathcal{O}_\ell$ . The constraints in (26) are imposed to keep the generation and the load within each transaction balanced in the congestion relief so as to prevent the IGO from implicitly arranging new transactions among market participants.

The formulation in (16)-(26) obtains a linear program for the IGO's least-price congestion relief problem. This congestion management problem formulation is very general and includes the various formulations [9][10] that previously appeared in the literature as special cases. In particular, without the equality constraints in

(22),  $\sum_{m \in \hat{\mathcal{M}}} \Delta p_k^{(m)}$  is replaced by  $\Delta p_k$  so that the

formulation of the scheme in [9] results; in addition, without the separation of markets constraint in (26), the formulation becomes that in [10].

We next undertake the optimality analysis. We denote by  $\Delta p_k^{*(m)}$  and  $Z^*$  the optimal solution and the corresponding congestion relief costs, respectively. We denote the values of the dual variables at the optimum associated with (22) and (23) by  $\rho_\ell^{*(m)}$  and  $\mu_\ell^*$ , respectively. Note that  $\mu_\ell^* \geq 0$ . We consider the sensitivity  $\chi_\ell^* = -\partial Z^*(f_\ell^{\max}) / \partial f_\ell^{\max} = \partial Z^*(f_\ell) / \partial f_\ell$ .

We use the LP formulation to evaluate

$$\chi_\ell^* = \begin{cases} \mu_\ell^* + \sum_{m \in \mathcal{O}_\ell} \left[ \frac{\rho_\ell^{*(m)} \varphi_\ell^{(m)} t^{(m)}}{\sum_{m' \in \mathcal{O}_\ell} \varphi_\ell^{(m')} t^{(m')}} \right] & \text{if } \ell \in \tilde{\mathcal{L}} \\ \mu_\ell^* & \text{otherwise} \end{cases} \quad (27)$$

For  $\ell \in \tilde{\mathcal{L}}$ , one unit decrease in  $f_\ell^{\max}$  results in

an increase of  $\frac{\varphi_\ell^{(m)} t^{(m)}}{\sum_{m' \in \mathcal{O}_\ell} \varphi_\ell^{(m')} t^{(m')}}$  in the congestion

burden associated with each transaction  $m \in \mathcal{O}_\ell$ .

Thus, the first component of  $\chi_\ell^*$  in (26) is the sum of the additional congestion expenditures incurred by the IGO in relieving the increased congestion burdens. The expenditures  $\mu_\ell^*$  are incurred to ensure that there is no overload in the



IGO-determined schedule. We may use  $\chi_\ell^*$  to set up the uniform transmission usage prices charged to each transaction for its flows on line  $\ell$  in the IGO-determined schedules. Note, however, that  $\chi_\ell^*$  may be negative for some  $\ell \in \tilde{\mathcal{L}}$ . The physical interpretation of a negative  $\chi_\ell^*$  is that a decrease in the flow limit  $f_\ell^{\max}$  or equivalently an increase in the line flow  $f_\ell$  in the preferred schedule is the optimal decision to minimize the congestion costs  $Z^*$  incurred by the IGO. Then, in order to attain the optimum in congestion management, the IGO must reward those transactions whose flows on line  $\ell$  produce such an effect.

We can specify the usage charges for each transaction  $m$ . In the IGO-determined schedule, the flow  $f_\ell^{*(m)}$  associated with transaction  $m$  in line  $l$  is approximated by

$$\hat{f}_\ell^{*(m)} \approx \varphi_\ell^{(m)} f_\ell^{(m)} + \sum_{k \in \mathcal{K}} \psi_{\ell,k} \Delta p_k^{*(m)} \quad (28)$$

where  $\varphi_\ell^{(m)} f_\ell^{(m)}$  is the flow in line  $\ell$  attributable to transaction  $m$  in the preferred schedule, and

$\sum_{k \in \mathcal{K}} \psi_{\ell,k} \Delta p_k^{*(m)}$  is the change in the line flow

that is due to the relief actions associated with transaction  $m$ . The usage charge to transaction  $m$  on line  $l$  is

$$X_\ell^{(m)} = \chi_\ell^* \hat{f}_\ell^{*(m)} \quad (29)$$

Note that this charge is imposed uniformly on all transactions that contribute to the overload and is consequently a nondiscriminatory charge.

#### 4. NUMERICAL RESULTS

We implemented and tested on several systems the proposed congestion management allocation scheme. We illustrate the capabilities of the scheme and discuss some key policy implications using the two test systems described in Appendices B and C. These two systems are derived from the IEEE 30-bus and 57-bus networks with three transactions and four transactions, respectively.

We use the system in Appendix B to illustrate the capability of the proposed overload allocation scheme to attribute the overloads to the various transactions. The lines whose flows in the preferred schedules are over their limits

are lines 3 and 6 that join buses 2 with 4 and 2 with 6, respectively. Then,  $\tilde{\mathcal{L}} = \{3, 6\}$ . The values of the factors  $\varphi_\ell^{(m)}$  computed by Equation (10) are given in Table 1. Note that the magnitudes and the signs of  $\varphi_\ell^{(m)}$  vary. Take for instance transaction 2, which has  $\varphi_\ell^{(m)}$  with the smallest magnitudes. We interpret that the impacts of transaction 2 on the line flows are the least marked of the three transactions. As another example, consider the  $\varphi_\ell^{(m)}$  associated with transaction 1. The signs indicate that while we attribute flows to the dominant flow in line 3, there is associated flow that contributes to the counter flow in line 6. These effects are due largely to the particular locations of the sellers and the buyers of transactions. The sets  $\mathcal{D}_l$  associated with lines 3 and 6 are  $\{1, 3\}$  and  $\{2, 3\}$ , respectively, and  $\mathcal{C}_l$  is simply the complement of  $\mathcal{D}_l$  in  $\mathcal{M}$  in each case. The nonempty sets  $\tilde{\mathcal{L}}^{(m)}$  for each transaction  $m = 1, 3$  are  $\{3\}$ ,  $\{6\}$ , and  $\{3, 6\}$ , respectively. Note that

$$\mathcal{M} = \bigcup_{l \in \tilde{\mathcal{L}}} \mathcal{D}_l = \mathcal{M} = \{1, 2, 3\}.$$

Table 1. The  $\varphi_\ell^{(m)}$  values for the overloaded lines for the test system in Appendix B

| transaction $m$ | 1      | 2      | 3     |
|-----------------|--------|--------|-------|
| overloaded line |        |        |       |
| 3               | 0.014  | -0.006 | 0.119 |
| 6               | -0.015 | 0.007  | 0.164 |

We use the allocation scheme in Equation (15) to determine the contribution to the congestion attributed to each transaction. The overload allocation results are summarized in Table 2.

Table 2. The overload allocation results in MW for the test system in Appendix B<sup>5</sup>

| Overloaded line |                          | $\Delta f_\ell^{(m)}$ for transaction |      |      |
|-----------------|--------------------------|---------------------------------------|------|------|
| $l$             | overload $\Delta f_\ell$ | 1                                     | 2    | 3    |
| 3               | 2.70                     | 0.19                                  | -    | 2.51 |
| 6               | 3.25                     | -                                     | 0.07 | 3.18 |

<sup>5</sup> A dash entry in Table 1 indicates that transaction  $m$  does not contribute to the overload in the specific line.

Next, we examine the case in which the generators at buses 2, 13, 22 and 23 decide to participate into the IGO's adjustment auction. Hence,  $\mathcal{K} = \{2, 13, 22, 23\}$ . The offer data of these four generators are tabulated in Table 3. The values of the  $\psi_{\ell,k}$  associated with the overloaded lines and the adjustment auction buses are shown in Table 4.

Table 3. The offer data in the IGO's adjustment auction for the test system in Appendix B

| offerer at bus $k$<br>offer data | participants in transaction 2 |     | Participants in transaction 3 |    |
|----------------------------------|-------------------------------|-----|-------------------------------|----|
|                                  | 22                            | 23  | 2                             | 13 |
| $c_k^+$ (\$/MWh)                 | 15                            | 10  | 10                            | 20 |
| $c_k^-$ (\$/MWh)                 | 10                            | 7.5 | 10                            | 15 |
| $\Delta p_k^{max}$ (MW)          | 15                            | 30  | 25                            | 20 |
| $\Delta p_k^{min}$ (MW)          | 15                            | 10  | 20                            | 20 |

Table 4. The  $\psi_{\ell,k}$  values for the test system in Appendix B

| line $\ell$<br>adjustment bus $k$ | 22    | 23    | 2     | 13    |
|-----------------------------------|-------|-------|-------|-------|
|                                   |       |       |       |       |
| 3                                 | -0.21 | -0.22 | 0.07  | -0.24 |
| 6                                 | 0.05  | -0.23 | -0.26 | -0.25 |

The LP optimal solution  $\Delta p_k^{*(m)}$ ,  $k \in \mathcal{K}$ ,  $m \in \hat{\mathcal{M}}$  in MW is shown in Table 5. These results indicate that transactions 2 and 3 are modified in the IGO-determined schedule. For transaction 2, in which the generators at buses 22 and 23 participate, the output of the generator at bus 22 is decreased by 3.04 MW. Due to the separation of markets constraint for transaction 2 represented by Equation (26), the 3.04 MW decrease must be replaced by the only entity in transaction 2 participating in the adjustment auction, the generator at bus 23. As such, in transaction 2, there is a 3.04 MW shift of generation from the generator at bus 22 to that at bus 23. Similarly, in transaction 3, 11.5 MW of generation is shifted from the generator at bus 2 to that at bus 13. Since none of the generators and loads that participate in transaction 1 takes part in the adjustment auction, transaction 1 remains unchanged in the IGO-determined schedule. We may infer that transaction 1 is willing to pay whatever usage charges may result

from the auction to keep intact its transaction in the IGO-determined schedule. It does so by simply avoiding to participate in the adjustment auction.

We use the test system in Appendix B to illustrate the impacts of the separation of markets

Table 5. The optimal solution  $\Delta p_k^{*(m)}$  in MW for the test system in Appendix B

| trans. $m$<br>bus $k$                       | participants in trans. 2 |       | participants in trans. 3 |      |
|---------------------------------------------|--------------------------|-------|--------------------------|------|
|                                             | 22                       | 23    | 2                        | 13   |
| 1                                           | 0                        | -1.63 | -7.87                    | 0    |
| 2                                           | -9.69                    | -2.70 | -11.5                    | 11.5 |
| 3                                           | 6.65                     | 7.37  | 7.87                     | 0    |
| net injection adjustments<br>$\Delta p_k^*$ | -3.04                    | 3.04  | -11.5                    | 11.5 |

Table 6. Values of  $\Delta p_k^*$ ,  $k \in \mathcal{K}$  in MW of the LP without the separation of markets constraints for the test system in Appendix B

| offerer bus $k$                             | participants in trans. 2 |    | participants in trans. 3 |        |
|---------------------------------------------|--------------------------|----|--------------------------|--------|
|                                             | 22                       | 23 | 2                        | 13     |
| net injection adjustments<br>$\Delta p_k^*$ | 2.40                     | 23 | -9.87                    | -15.53 |

constraint in Equation (26). We resolve the LP optimization with the separation of markets constraints ignored. We assume that the offerers and their offers do not change. The net injection adjustments  $\Delta p_k^*$ ,  $k \in \mathcal{K}$  in MW at the optimum are shown in Table 6. The results in Table 6 clearly indicate that the IGO implicitly forces the market participants to undertake new transactions which were not contemplated by the market players as evidenced by the submitted preferred schedule. For example, let us consider transaction 3 in which the generators at buses 2 and 13 participate. In the IGO-determined schedule, the outputs of the generators at buses 2 and 13 are reduced by 9.87 MW and 15.53 MW, respectively. The total reduction of 25.4 MW is replaced by the IGO by increasing the output of the generators at bus 22 and bus 23. These two entities, however, do not participate in transaction 3. So the IGO effectively forces the

loads in transaction 3 to replace the 25.4 MW reduction through the purchase of an equal quantity from the generators at buses 22 and 23. In effect, the IGO establishes a new transaction that was not entered into by the participants. As such, the IGO, whose responsibility is to remove the congestion in order to maintain system reliability, is seen as intervening in the market. The **separation of markets** constraint was specifically introduced to prevent the occurrences of such interference.

Next, we turn our attention to the test system in Appendix C. There are three overloaded lines in the preferred schedule. They are lines 2, 3 and 18 that join buses 2 with 3, 3 with 4, and 3 with 15, respectively. The overload allocation results determined by Equation (15) are given in Table 7.

Table 7. The overload allocation results in MW for the test system in Appendix C<sup>6</sup>

| Overloaded line |                            | $\Delta f_{\ell}^{(m)}$ for transaction |     |     |     |
|-----------------|----------------------------|-----------------------------------------|-----|-----|-----|
| $\ell$          | overload $\Delta f_{\ell}$ | 1                                       | 2   | 3   | 4   |
| 2               | 4.9                        | 3.3                                     | 1.6 | -   | -   |
| 3               | 7.5                        | 4.5                                     | 1.3 | 1.7 | -   |
| 3               | 3.5                        | -                                       | 1.0 | 0.6 | 1.9 |

We consider that the generators at buses 2, 3, 8, 9 and 12 and the load at bus 6 wish to participate in the IGO's adjustment auction. Hence,  $\mathcal{K} = \{2, 3, 6, 8, 9, 12\}$ . The offer data of the six offerers are given in Table 8. Note that the generators at buses 3 and 12 are participants in transaction 3 and the generators at buses 8 and 9 are participants in transaction 4; however, the generator at bus 2 and the load at bus 6 are not involved in any of the four transactions. The values of the  $\psi_{\ell,k}$  associated with the overloaded lines and the adjustment auction buses are shown in Table 9.

Table 8. The offer data in the IGO's adjustment auction for the test system in Appendix C

| offerer at bus $k$   | Participants in trans. 3 |    | Participants in trans. 4 |    | Other participants |      |
|----------------------|--------------------------|----|--------------------------|----|--------------------|------|
|                      | 3                        | 12 | 8                        | 9  | 2                  | 6    |
| offer data           |                          |    |                          |    |                    |      |
| $c_k^{\pm}$ (\$/MWh) | 25                       | 25 | 30                       | 15 | 20                 | 22.5 |

<sup>6</sup> A dash entry in Table 1 indicates that transaction  $m$  does not contribute to the overload in the specific line.

|                         |     |       |     |     |     |    |
|-------------------------|-----|-------|-----|-----|-----|----|
| $c_k^{\pm}$ (\$/MWh)    | 10  | 20    | 15  | 7.5 | 8   | 10 |
| $\Delta p_k^{max}$ (MW) | 20  | 15    | 20  | 20  | 10  | 15 |
| $\Delta p_k^{min}$ (MW) | -15 | -17.5 | -10 | -25 | -15 | -5 |

Table 9. The  $\psi_{\ell,k}$  values for the test system in

#### Appendix C

| bus $k$ \ line $\ell$ | 3    | 12    | 8     | 9     | 2    | 6     |
|-----------------------|------|-------|-------|-------|------|-------|
| 2                     | 0.39 | -0.15 | 0.23  | 0.21  | 0.13 | 0.28  |
| 3                     | 0.18 | -0.04 | -0.22 | -0.13 | 0.04 | -0.41 |
| 18                    | 0.36 | -0.11 | 0.01  | 0.08  | 0.09 | 0.13  |

The LP optimal solution  $\Delta p_k^{*(m)}, k \in \mathcal{K}, m \in \hat{\mathcal{M}}$  in MW is tabulated in Table 10. The optimal results indicate that transactions 3 and 4 are modified in the IGO-determined schedule. These modifications take into consideration the separation of markets constraint for the transactions. In transaction 3, 8.0 MW of generation are switched from the generator at bus 3 to the generator at bus 12, and in transaction 4 4.0 MW of generation are shifted from the generator at bus 8 to that at bus 9. The generator at bus 2 and the load at bus 6, which are not participants in transactions 3 and 4, cannot participate in the modification of these two transactions. Since none of the generators and loads that participate in transactions 1 and 2 participates in the adjustment auction, then transactions 1 and 2 remain unchanged in the IGO-determined schedule. The optimal solution in Table 10 also shows that the IGO cuts 13.7 MW from the generator at bus 2 and this reduction is balanced by reducing the load at bus 6 by exactly 13.7 MW. We may interpret these congestion relief actions of the IGO as, in effect, purchasing 13.7 MW injection from the load at bus 6 and selling the same quantity to the generator at bus 3. In this way the IGO acts as a middleman since he does not have any physical resources, neither generators nor loads. Since the generator at bus 2 and the load at bus 6 do not participate in any of the submitted preferred transactions, these "IGO-arranged" transactions are not in violation of the separation of markets constraints.

Table 10. The optimal solution  $\Delta p_k^{*(m)}$  in MW for the test system in Appendix C

| trans. $m$ \ bus $k$                     | participants in trans. 3 |     | participants in trans. 4 |     | other participants |      |
|------------------------------------------|--------------------------|-----|--------------------------|-----|--------------------|------|
|                                          | 3                        | 12  | 8                        | 9   | 2                  | 6    |
| 1                                        | -1.4                     | 3.0 | 0                        | 4.0 | 0                  | 8.9  |
| 2                                        | -0.8                     | 0   | 0                        | 0   | -10.6              | 1.8  |
| 3                                        | -1.3                     | 5.0 | 0                        | 0   | 0                  | 3.1  |
| 4                                        | -4.5                     | 0   | -4.0                     | 0   | -3.1               | -0.1 |
| net injection adjustments $\Delta p_k^*$ | -8.0                     | 8.0 | -4.0                     | 4.0 | -13.7              | 13.7 |

The transmission usage price  $\chi_\ell^*$  and the total usage charges  $X^{*(m)}$  charged to each transaction  $m$  are shown in Table 11. The negative usage charges for a line indicate that the transaction is being reimbursed by the IGO for use of the line. The rationale for this payment is to induce, in effect, a counter flow in the line so as to be able to increase the dominant flow through the line.

We illustrate some of the latitude that the auction-based congestion management scheme provides to transactions. The voluntary nature of the adjustment auction allows a transaction to decide on its own whether or not to participate and how to construct its offer effectively so as to achieve the desired portfolio in the IGO-determined schedule. Consider in the test system, that transaction 4 that is modified in the IGO-determined schedule. To reflect that transaction 4 desires to remain unchanged, the transaction raises the price  $c_9^+$  offered by its generator at bus 9 from \$15/MWh to \$35/MWh, making it the most expensive bidder in the auction. The modified LP problem solution with the increased  $c_9^+$  has  $\Delta p_9^* = \Delta p_8^* = 0$  leaving transaction 4 unchanged. However, the decision by transaction

4 to raise  $c_9^+$  results in changes in the total usage charges  $X^{*(m)}$  paid by each transaction  $m$ . The modified usage payments show that while the IGO's usage payment to transaction 4 decreases by \$3343/h, the usage charges paid by the other transactions decrease.

While the auction-based congestion management mechanism allows transactions a great deal of freedom, the decision made by a market participant according to its own interests may disadvantage the system or even result in the failure of the IGO's congestion relief. For example, suppose that the generator at bus 8 of transaction 4 decides not to participate in the adjustment auction. Consequently,  $\Delta p_8$  stops being a decision variable for the LP problem. We assume that all the other offerers and their offers remain unchanged. Without the presence of  $\Delta p_8$  as a decision variable for the IGO, however, the LP problem does not even have a feasible solution. It means that the overloads cannot be removed from the network in this case with the set of offers received. Consequently, in order to ensure that the indispensable relief services from the generator at bus 8 are available, the IGO must designate it as a *reliability must run* unit and pay for its relief service at the contractually negotiated price.

We examine the capability of the congestion management allocation scheme to respond to variations in the amount of a transaction. Let us focus on transaction 2. While all other transactions are kept fixed, we vary the amount of transaction 2 using a scaling factor  $0.95 \leq \gamma \leq 1.05$ , where  $\gamma=1$  corresponds to the reference case. Now, the flow associated with transaction 2 contributes to the dominant flow in the overloaded line 3, so that the overload  $\Delta f_3$  increases as the amount of transaction 2 increases, as shown in Figure 2. The overload  $\Delta f_3^{(2)}$  allocated to transaction 2 also increases

Table 11. The transmission usage charges  $\chi_\ell^{*(m)}$  and total usage charges  $X^{*(m)}$

| Line $l$                              | $\chi_\ell^*$ (\$/MWh) | $f_\ell^{*(m)}$ (MW) / $X_\ell^{*(m)}$ (\$/h) for transaction |             |             |               |
|---------------------------------------|------------------------|---------------------------------------------------------------|-------------|-------------|---------------|
|                                       |                        | 1                                                             | 2           | 3           | 4             |
| 2                                     | 98.4                   | 70.4 / 6933                                                   | 34.2 / 3362 | -2.8 / -275 | -36.4 / -3585 |
| 3                                     | 44.7                   | 58.0 / 2613                                                   | 17.0 / 764  | 22.0 / 990  | -73.2 / -3299 |
| 18                                    | 129.9                  | -24.7 / -3202                                                 | 17.1 / 2112 | 10.3 / 1336 | 31.6 / 4127   |
| 1                                     | 81.1                   | 74.7 / 6054                                                   | 34.9 / 2827 | 9.8 / 798   | -37.2 / -3015 |
| total usage charges $X^{*(m)}$ (\$/h) |                        | 12,398                                                        | 9,164       | 2,849       | -5,773        |

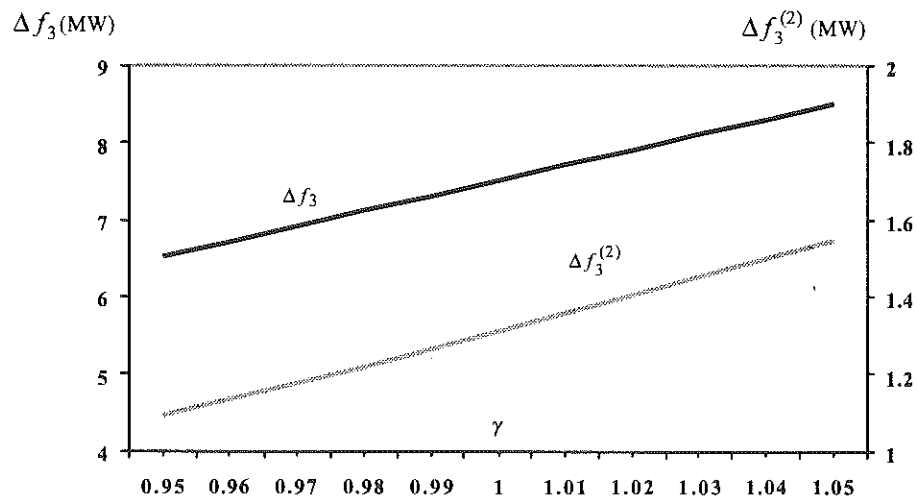


Figure 2 The variations of  $\Delta f_3$  and  $\Delta f_3^{(2)}$  as a function of the scaling factor  $\gamma$  for the test system in Appendix C

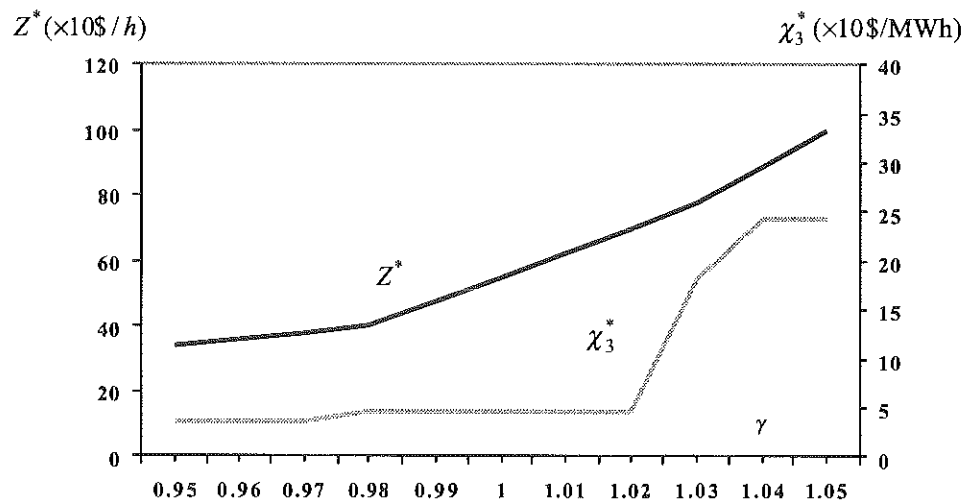
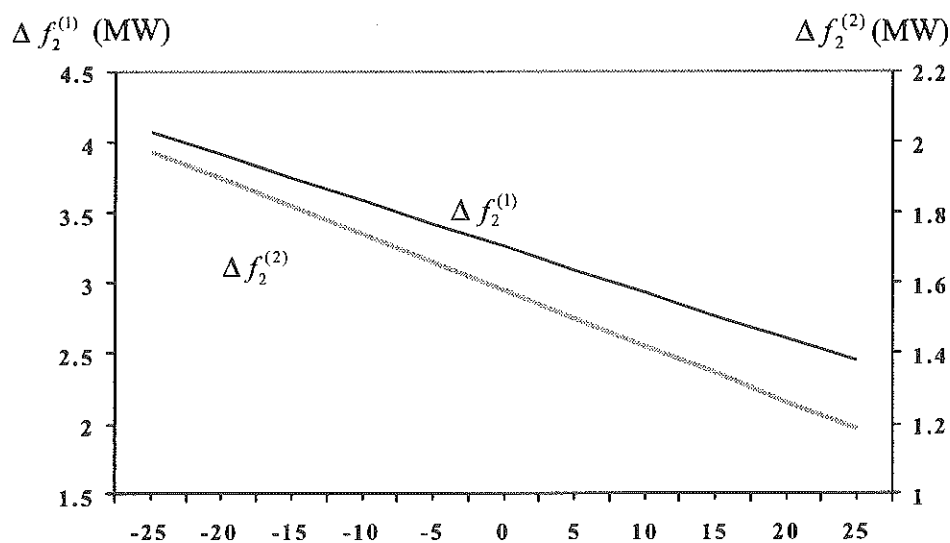


Figure 3. The variations of the total congestion management costs  $Z^*$  and the usage price  $\chi_3^*$  on line 3 as a function of the scaling factor  $\gamma$  for the test system in Appendix C



percentage change of  $f_2^{max}$  as a function of the reference value

Figure 4. Plot of  $\Delta f_2^{(1)}$  and  $\Delta f_2^{(2)}$  as a function of uncertainty in the value of  $f_2^{max}$  for the test system in Appendix C

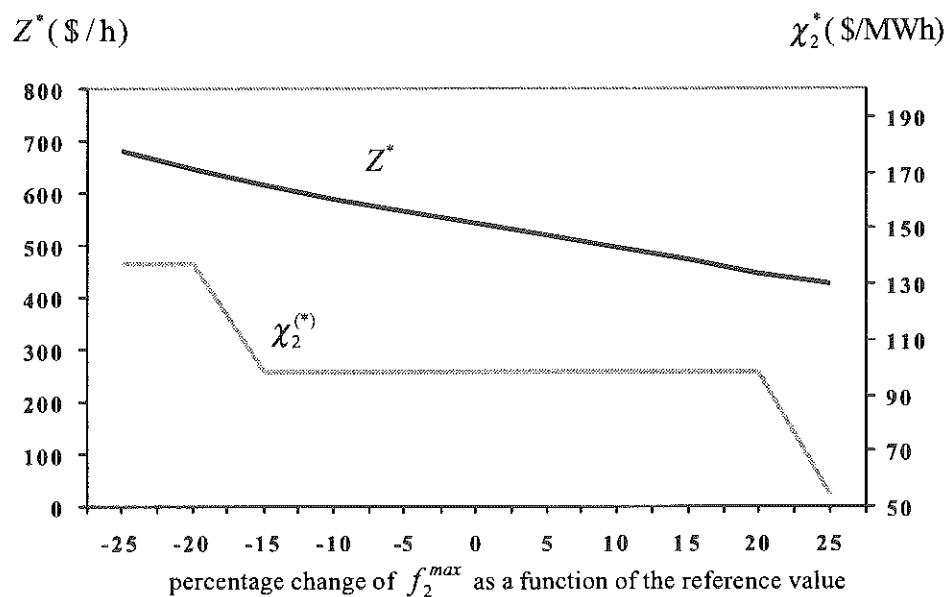


Figure 5. Plot of  $Z^*$  and  $\chi_2^*$  as a function of uncertainty in the value of  $f_2^{max}$  for the test system in Appendix C

over this range and is also shown in Figure 2. Since the overloads and the allocations of the overloads to transaction 2 on lines 2 and 18 increase as the amount of transaction 2 increases and results in the removal of the larger overloads as the amount of the transaction increases, both the total congestion costs  $Z^*$  and the usage price  $\chi_3^*$  associated with line 3 increase as a function of the scaling factor  $\gamma$ . This is shown in Figure 3. As illustrated in Figures 2 and 3, the congestion management results and the corresponding transmission usage charges given by the proposed scheme behave in an appropriate manner when the amount of a transaction varies

We also study the sensitivity of the LP optimal solution to uncertainty: we examine the change in the optimum with respect to one of the line flow limits,  $f_2^{max}$  of line 2. Since we represent all the transmission constraints in terms of the line flow limits, the values specified for  $f_2^{max}$  may involve considerable uncertainty. We investigate the behavior of the scheme with the uncertainty in such a parameter being explicitly represented. Let the range of the uncertainty of  $f_2^{max}$  be in an interval of  $\pm 25\%$  around its reference value. We illustrate the effects of this uncertainty on the optimal solution with respect to the overloads and the resulting congestion management costs/charges. As the limit  $f_2^{max}$  decreases, the overload  $\Delta f_2$  on line 2 increases. In turn, the allocations  $\Delta f_2^{(1)}$  and  $\Delta f_2^{(2)}$  to transactions 1 and 2 correspondingly increase. Consequently, the IGO needs to remove the larger overloads attributed to transactions 1 and 2, and still ensure that no overloads occur in any of the lines of the system. The impacts on the allocated overloads  $\Delta f_2^{(1)}$  and  $\Delta f_2^{(2)}$  are shown in Figure 4. The changes increase the congestion relief costs  $Z^*$ . The usage price  $\chi_2^*$  on line no. 2 remains constant or increases as the line limit decreases as well. Figure 5 displays the impacts of the uncertainty on  $Z^*$  and  $\chi_2^*$  as a function of the  $f_2^{max}$  values. It follows from this example that the proposed congestion management allocation scheme has the ability to study the impact of parameter uncertainty involved in the modeling of the transmission constraints.

## 5. CONCLUSIONS

In this paper, we have developed a physical-flow-based congestion management allocation scheme for multiple transaction networks. The work in this paper gives rise to several topics that require further investigation. One of the chief simplifications made in the development of the congestion management allocation scheme is the representation of all the transmission constraints in terms of line flow limits. Since such a simplifying modeling approach may be inadequate particularly for the case in which the transmission system congestion is due to voltage or stability limits - more realistic models that can explicitly represent the congestion in terms of the voltage or stability constraints are required. The development of an allocation mechanism of transmission congestion caused by voltage or stability constraints constitutes a major challenge. The consideration of contingency needs to be incorporated into the congestion management to take into account those cases where the system is not congested under the normal condition but becomes so under certain specified contingencies. This problem will require considerable effort to address the modeling and computational aspects.

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### BIOGRAPHIES

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### APPENDIX A: THE TRANSACTION FRAMEWORK-BASED DC POWER FLOW

We consider a system of  $N+1$  buses with bus 0 being designated as the slack bus. We denote by  $\hat{\theta} = [\hat{\theta}_1, \hat{\theta}_2, \dots, \hat{\theta}_N]^T$  the voltage angle vector computed by the DC power flow. Let  $\hat{B}$  be the  $N \times N$  submatrix of the  $(N+1)$ -node (argued) network susceptance matrix  $\underline{B}$  [14]. Without any loss of generality we may set  $\hat{\theta}_0 = 0$ . The DC power flow formulation of the transaction-based network then is

$$\hat{B} \hat{\theta} = \underline{p} - \sum_{m \in \mathcal{M}} \underline{\delta}^{(m)} t^{(m)} \quad (A1)$$

where  $\underline{p} \triangleq [p_1, p_2, \dots, p_N]^T$  is the vector of the net nodal injection. Let

$$\underline{D} = [d_{ij}] = \hat{B}^{-1} \quad (A2)$$

Then,

$$\hat{\theta}_n = - \sum_{k=1}^N d_{nk} p_k = - \sum_{m \in \mathcal{M}} \sum_{k=1}^N d_{nk} \delta_k^{(m)} t^{(m)}, n = 1, 2, \dots, N \quad (A3)$$

Let us rewrite Equation (32) as

$$\hat{\theta}_n = \sum_{m \in \mathcal{M}} \mu_n^{(m)} t^{(m)}, n = 1, 2, \dots, N \quad (A4)$$

where we define, for  $n = 1, 2, \dots, N$ ,

$$\mu_n^{(m)} = - \sum_{k=1}^N d_{nk} \delta_k^{(m)} = \sum_{j=1}^{N_b^{(m)}} d_{nj} \beta_j^{(m)} - \sum_{i=1}^{N_s^{(m)}} d_{ni} \sigma_i^{(m)} \quad (A5)$$

For completeness, we define  $\mu_0^{(m)} = 0, m \in \mathcal{M}$ ,  $d_{n0} = 0, n = 1, 2, \dots, N$ . Then, for  $i \neq j$ ,

$$\hat{\theta}_i - \hat{\theta}_j = \sum_{m \in \mathcal{M}} \pi_{ij}^{(m)} t^{(m)}, i, j = 0, 1, 2, \dots, N. \quad (A6)$$

with

$$\pi_{ij}^{(m)} = \mu_i^{(m)} - \mu_j^{(m)}, m \in \mathcal{M}, i, j = 0, 1, \dots, N \quad (A7)$$

We may also rewrite (A6) as

$$\hat{\theta}_i - \hat{\theta}_j = \sum_{k=1}^N (d_{kj} - d_{ki}) p_k. \quad (A8)$$

### APPENDIX B: THE TEST SYSTEM

The test system is constructed on the basis of the IEEE 30-bus system. We use the generation/load data of the 30-bus system to construct three transactions. The transaction profiles are tabulated in Table 12.

Table 12. The transaction profiles of the test system

| trans. $m$ | $t^{(m)}$<br>(MW) | $\mathcal{S}^{(m)}$          | $\mathcal{G}^{(m)}$                                                                              |
|------------|-------------------|------------------------------|--------------------------------------------------------------------------------------------------|
| 1          | 50.2              | $\{(1, 46\%), (27, 100\%)\}$ | $\{(7, 18\%), (14, 12\%), (15, 16\%), (16, 7\%), (17, 18\%), (18, 6\%), (19, 19\%), (20, 4\%)\}$ |
| 2          | 37.6              | $\{(22, 57\%), (23, 43\%)\}$ | $\{(8, 5\%), (10, 15\%), (21, 47\%), (24, 23\%), (26, 10\%)\}$                                   |



|   |       |                                                                        |                                                                                                                             |
|---|-------|------------------------------------------------------------------------|-----------------------------------------------------------------------------------------------------------------------------|
| 3 | 76.31 | $\left\{ \begin{array}{l} (2,52\%), \\ (13,48\%) \end{array} \right\}$ | $\left\{ \begin{array}{l} (3,3\%),(4,10\%), \\ (7,18\%),(8,37\%), \\ (12,15\%),(29,3\%), \\ (30,14\%) \end{array} \right\}$ |
|---|-------|------------------------------------------------------------------------|-----------------------------------------------------------------------------------------------------------------------------|

### APPENDIX C: THE TEST SYSTEM

The test system is constructed on the basis of the IEEE 57-bus system. We use the generation/load data of the 57-bus system to construct four transactions. The transaction profiles are tabulated in Table 13.

Table 13. The transaction profiles of the test system

| trans. $m$ | $t^{(m)}$<br>(MW) | $\mathcal{S}^{(m)}$                                                    | $\mathcal{G}^{(m)}$                                                                                                                                                                                                                                                                                                               |
|------------|-------------------|------------------------------------------------------------------------|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| 1          | 282               | $\{(1,100\%)\}$                                                        | $\left\{ \begin{array}{l} (2,1\%),(3,15\%), \\ (5,4\%),(6,27\%), \\ (8,53\%) \end{array} \right\}$                                                                                                                                                                                                                                |
| 2          | 197               | $\{(1,100\%)\}$                                                        | $\left\{ \begin{array}{l} (9,61\%),(10,3\%), \\ (13,9\%),(14,5\%), \\ (16,22\%) \end{array} \right\}$                                                                                                                                                                                                                             |
| 3          | 322               | $\left\{ \begin{array}{l} (3,12\%), \\ (12,88\%) \end{array} \right\}$ | $\left\{ \begin{array}{l} (15,7\%),(17,13\%), \\ (18,8\%),(19,1\%), \\ (23,2\%),(25,2\%), \\ (27,3\%),(28,1\%), \\ (29,5\%),(30,1\%), \\ (31,2\%),(33,1\%), \\ (35,2\%),(38,4\%), \\ (41,2\%),(42,2\%), \\ (44,4\%),(47,9\%), \\ (49,6\%),(50,7\%), \\ (51,6\%),(52,2\%), \\ (53,6\%),(54,1\%), \\ (57,1\%) \end{array} \right\}$ |
| 4          | 450               | $\left\{ \begin{array}{l} (8,78\%), \\ (9,22\%) \end{array} \right\}$  | $\left\{ \begin{array}{l} (1,12\%),(12,84\%), \\ (55,2\%),(57,2\%) \end{array} \right\}$                                                                                                                                                                                                                                          |

## A Wheeling Evaluation System for System Operator in a Deregulated Environment Considering Power System Security

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### Abstract

The authors propose a wheeling evaluation system for secure power system operation under a deregulated environment. The proposed system is intended to be a support tool for the system operator by evaluating acceptability of multiple retail wheeling requests from a viewpoint of power system security. The paper presents a PC-based prototype system of the wheeling evaluation system with its application results as well as its algorithm.

### Introduction

Like in many countries, deregulation of the electricity industry is now in progress in Japan. In March 2000, competition in the retail electricity market was partially introduced [1]. Non-utility power suppliers other than electric power utilities have been allowed to retail electricity since. Retail wheeling schemes via transmission network owned and operated by utilities are created. Eligible large-scale customers whose demands are more than 2,000 kW of electricity at 20 kV or above, corresponding to approximately 30% of the volume of electricity sales in Japan, can choose their electricity suppliers based on bilateral contracts.

In the framework of this deregulation scheme, utility system operator still has the responsibility to maintain transmission network security and reliability. The system operator has to evaluate acceptability of retail wheeling requests from non-utility power suppliers, considering the network security constraints. When the total volume of retail wheeling increases, power system operation will become more complicated to deal with those wheeling requests in order to keep the system security. Hence, useful support tools for the system operator are expected more and more.

In such situations, what the system operator wants to know will be as follows:

- (1) In case of accepting all wheeling requests, will the system security be maintained?
- (2) What is the influence of individual wheeling requests upon the system security?
- (3) If some security violations due to retail wheeling occur,

what measures (security actions) should be taken to keep the system security?

- (4) How much will the cost of these security actions be?

In this paper, the authors propose a wheeling evaluation system for the power system operator, which provides answers to the above questions. A PC-based prototype system of the wheeling evaluation system developed by the authors is presented with its application results as well as its algorithm.

### Wheeling Evaluation System

The wheeling evaluation system proposed by the authors is intended to be a support tool for the power system operator. In this section, basic functions of the proposed system are briefly described.

#### *Security Based Wheeling Evaluation*

The primary function of the proposed system is to evaluate acceptability of multiple retail wheeling requests.

Power system security in case of accepting all wheeling requests is first evaluated. At the same time, influence of the individual wheeling request upon the system security is also evaluated. The N-1 criteria are used here. On the basis of these evaluation results, acceptability of each wheeling request is determined.

In general, security constraints to be considered in the evaluation will be as follows:

- Branch overload
- Node voltage limit
- Steady-state stability
- Transient stability
- Mid-term stability
- Voltage stability

The wheeling evaluation system is designed so that power system operator can select some of the security constraints because priority of the security constraints depends on their transmission network characteristics.

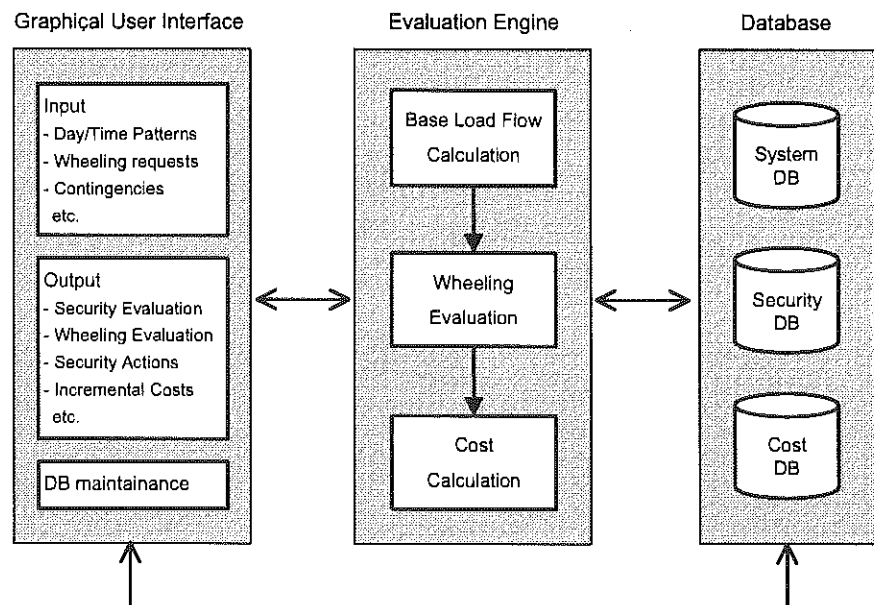


Figure 1: Schematic Diagram of Wheeling Evaluation System

#### Security Measures Evaluation

If some security violations are found in the above evaluation considering all wheeling requests, the wheeling evaluation system then calculates and indicates the measures for the system operator to take. These measures are called *security actions* in the paper, and will prevent the occurrence of the security violations.

#### Incremental Cost Evaluation

Moreover, the wheeling evaluation system calculates incremental costs for the power system operation considering retail wheeling. For example, costs for the incremental transmission losses due to retail wheeling and costs for the security actions will be the incremental costs.

These incremental costs can be considered as those of wheeling costs, or penalties. Hence, they may be charged to the individual wheeling requests according to their security influence evaluated above. A wheeling request that makes the system security worse will be charged more.

#### Graphical User Interface

The evaluation results are visualized by a user-friendly graphical user interface (GUI). Hence, system operator can clearly and promptly understand the influence of wheeling requests upon the system security, effective security actions, and so on.

#### System Configuration

Schematic diagram of the proposed wheeling evaluation system is shown in Fig. 1. The system consists of the following three parts:

- Graphical user interface part
- Evaluation engine part
- Database (DB) part

#### PC-based Prototype System

The rest of the paper describes a PC-based prototype system of the wheeling evaluation system developed by the authors. The prototype system will be demonstrated at the conference presentation.

#### Features

The features of the prototype system is as follows:

- Working on a personal computer (PC)
- Static security evaluation capability for large scale transmission network based on load-flow analysis
- Visualized evaluation results provided by GUI

#### Restrictions

The current prototype system deals with given *one* load-flow condition for off-line use. Hence, it is appropriate for the planning purpose so far.

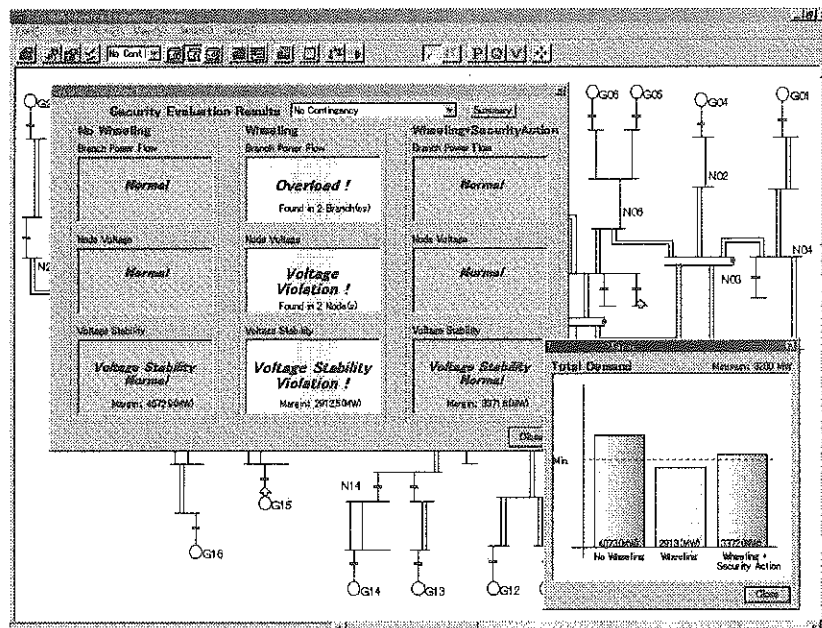


Figure 2: Example display of wheeling evaluation results (1)

Three security constraints such as branch overload, node voltage limit, and voltage stability are taken into account. Voltage stability is evaluated using total demand margin of the power system as a stability index. Direct calculation method of the voltage stability limit [2] is used for the evaluation.

In order to avoid security constraint violations due to retail wheeling, the following security actions are considered:

- Generation re-scheduling
- Var compensation by shunt capacitor bank
- Transformer tap adjustment

#### Evaluation Algorithm

**Wheeling Evaluation.** The prototype system first evaluates the power system security based on the N-1 criteria in case of accepting all wheeling requests. It also evaluates the influence of individual wheeling request on the power system security and the acceptability of each wheeling request.

**Security Actions.** If some security violations due to retail wheeling are found, the prototype system then calculates security actions for the system operator to take to prevent the violations. In this calculation, quasi-minimization algorithm based on sensitivity analysis are used to determine the effective security actions

**Incremental Costs.** As an example of cost evaluation, the prototype system calculates two kinds of incremental costs.

One is the cost for incremental transmission losses due to the retail wheeling. It is called  $\Delta P_{LOSS}$  cost in the paper. The other is the cost for the security actions to avoid constraints violations. It is called *security cost* in the paper. Security cost due to generation re-scheduling is only considered at present. These two costs are calculated based on incremental fuel cost of generators. In the prototype system,  $\Delta P_{LOSS}$  cost is charged equally to every wheeling request, while security cost is charged to some of the wheeling requests that make the system security worse.

#### Example Results in Prototype System

Figures 2 shows an display of the security evaluation results. Security constraint violations (in branch overloads, node voltage limit, and voltage stability) due to retail wheeling are found, but is resolved by the security actions.

Figure 3 shows another display of the evaluation results. An arrow shown in the figure represents each wheeling request. These arrows are colored according to their evaluation results. For example, arrows in blue and red make the system security better and worse respectively, in other words, good and bad wheeling requests. An arrow in green is a neutral wheeling request concerning power system security. From the display shown in Fig. 3, the system operator can clearly understand the influence of each wheeling requests.

Figure 4 shows example results of the wheeling evaluation and incremental cost calculation in tabular format.

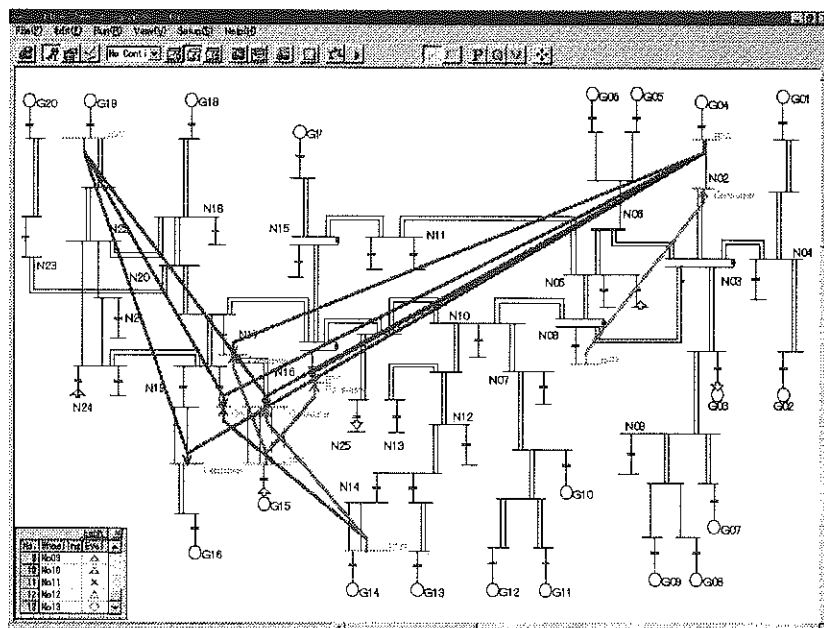


Figure 3: Example display of wheeling evaluation results (2)

### Further Improvements

Dynamic stability constraints such as transient and mid-term stability are not considered in the current prototype system. It will be implemented in the future version

For the practical use of the wheeling evaluation system, the following studies are needed:

- wheeling evaluation for a certain period of time
- extension to on-line use

### Conclusions

With the increase of retail wheeling volume, secure power system operation will become more and more complicated to deal with the wheeling requests. The wheeling evaluation system proposed in the paper will be a useful support tool for the system operator in the deregulated environment like that in progress in Japan.

Future deregulation schemes are not certain at present. In particular, institutional aspects of the deregulation such as wheeling rules, pricing rules, etc. may be changed further. The proposed system, however, covers general evaluation procedures to deal with the wheeling requests in order to keep the power system security, so that it does not depend on such institutional aspects of deregulation. It is one of the most important features of the proposed system.

| Summary (Action and Costs)  |                   |         |                                  |                     |                 |                        |       |                           |                          |
|-----------------------------|-------------------|---------|----------------------------------|---------------------|-----------------|------------------------|-------|---------------------------|--------------------------|
| Security Cost : 91 000yen/h |                   |         | Δ Power Loss Cost : 269 000yen/h |                     |                 | Δ Power Loss : 138 MW  |       |                           |                          |
| Generation Adj : 255.7 MW   |                   |         | Var Adj : 440 MW                 |                     |                 | Tap Adj : 1.0 of Trans |       |                           |                          |
| Wheeling Evaluation Results |                   |         | Adjustment                       |                     |                 | Total Cost (1000yen/h) |       |                           |                          |
| No                          | Wheeling Contract | PD Node | Consumer Node                    | Wheeling Power (MW) | Acceptable (MW) | Acceptable (MW)        | Eval. | Security Cost (1000yen/h) | Δ Power Cost (1000yen/h) |
| 4                           | No04              | G04A    | G16E                             | 50                  | 50              | 100                    | ×     | 1.10                      | 2.65                     |
| 5                           | No05              | G04A    | N19L                             | 70                  | 70              | 100                    | ×     | 1.54                      | 3.71                     |
| 6                           | No06              | G04A    | N16K                             | 10                  | 10              | 100                    | Δ     | 0.00                      | 0.53                     |
| 7                           | No07              | G04A    | G15E                             | 30                  | 30              | 100                    | ×     | 0.66                      | 1.59                     |
| 8                           | No08              | G04A    | N17K                             | 50                  | 50              | 100                    | ×     | 1.10                      | 2.65                     |
| 9                           | No09              | G15A    | N16K                             | 30                  | 30              | 100                    | Δ     | 0.00                      | 1.59                     |
| 10                          | No10              | G15A    | N17K                             | 30                  | 30              | 100                    | Δ     | 0.00                      | 1.59                     |
| 11                          | No11              | G14A    | N19L                             | 70                  | 70              | 100                    | ×     | 1.54                      | 3.71                     |
| 12                          | No12              | G14A    | G15E                             | 30                  | 30              | 100                    | Δ     | 0.00                      | 1.59                     |
| 13                          | No13              | N08K    | N02A                             | 30                  | 30              | 100                    | ○     | 0.00                      | 1.59                     |

|       |       |
|-------|-------|
| Graph | Close |
|-------|-------|

Figure 4: Wheeling evaluation results in tabular format

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## A Method of Voltage Stability Evaluation for Calculating Total Transfer Capability (TTC)

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### 1. Introduction

The computation of total transfer capability (TTC) is a significant task in the new deregulated power system environment [9]. Open access to electric power transmission networks has been carried out in order to foster generation competition and customer choice in the worldwide. Available transfer capability (ATC) is the largest additional amount of power above some base flow which can be transferred between two sets of buses under constraints such as voltage limits, overloads, stability, and n-1 contingencies. Total transfer capability (TTC) is defined as the amount of electric power that can be transferred over the interconnected transmission network in a reliable manner while meeting all of a specific set of defined pre-and post contingency system conditions [9].

This paper proposes an algorithm to calculate the critical state of power flow, which corresponds to the static stability limit of power systems under heavily loaded condition. The static stability limit is obtained by maximization of specified loads under several nodal constraints. Mathematical model is formulated in a set of nonlinear equations, which are derived from the sum of specified loads as objective function, and from practical constraints on every node.

The critical point of the power system can be calculated by Newton-Raphson method avoiding the singularity of Jacobian matrix. The matrices are processed by a sparse technique that minimizes the storage requirement and the computation time.

Static voltage stability limit of an electric power system gives the maximum limit of power transfer, or critical power flow, over transmission networks under a given operating condition. Accurate and fast calculation of such critical power flow conditions has an importance for the computation of total transfer capability (TTC). Traditional scenarios of voltage collapse have assumed all the load power consumption would increase simultaneously. However, it is not practical to assume the load of all areas of a power system would rise at the same time and at the same rate. It is more natural to con-

sider a particular set of loads or a particular area of loads would increase sharply. It is also desirable to develop an analytical method, which can flexibly handle such information as reactive power requirement and other various control conditions. In this paper, only the system condition of the present state is used for demonstrating TTC calculation, assuming that results of system state estimation are available and the operation point is stable and secure. Some assumptions are made in the paper for simplifying TTC calculation, it is assume the system has sufficiently large transient stability margin, hence it can survive the transient period and shift to a new steady state. Then the only stability constraint is voltage collapse at a critical point that can be solved for via continuation load flow. The TTC calculation will be in the steady state analysis domain [9].

This paper proposes a solution method for critical power flow, which maximizes a specified set of loads satisfying the energy conservation law and other constraints of the target power system. The proposed method was applied to the IEEE 14 bus test system and it is verified. The TTC can be calculated continuously and effectively against changing loads and system structures. Finally we give several general remarks on the future works to conclude this paper.

### 2. Consideration In Calculation Total Transfer Capability

The U.S. electricity industry has already experienced drastic restructuring procedures. The Federal Energy Regulatory Commission (FERC) has mandated through orders 888/889, the non-discriminatory access of the transmission facilities to wholesalers. To ensure a level playing field for all, FERC required that all parties have access to the same transmission information provided by the so-called Open Access Same Time Information system (OASIS) network. The OASIS should display extensive information about current operating conditions, scheduled transactions, ancillary services, and Available Transfer Capability (ATC) information [9,10]. ATC information is necessary to all players of the power market. It is defined as the measure of the transfer capability remaining in the physical transmission network for further commercial activity above already committed uses [7,8]. ATC must accu-

rately reflect the physical realities of the transmission network, all system conditions, uses, and limits in a consistent manner while not being complicated that it unduly constrains commerce. ATC determination depends on other parameters namely TTC, TRM, and CBM. Total Transfer Capability (TTC) is defined as amount of electric power that can be transferred over the interconnected transmission network in a reliable manner while meeting all of a specific set of defined pre-and post contingency system conditions. [7,8]. Transmission Reliability Margin (TRM) is that amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions. Capacity Benefit Margin (CBM) is defined as that amount of transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements. ATC mathematically is defined as TTC less TRM, less the sum of existing transmission commitments and the CBM [6,7].

TTC from a source to a sink represents the maximum transfer power from the Source bus to the sink bus with security constraints. It is time variable and dependent upon various conditions such as the corresponding operating conditions, system control capability and the contingencies used for TTC evaluation etc. Usually TTC will be constrained by the following: [9]

Thermal limits (branch MVA, Loading limits)  
Voltage limits (voltage magnitude limits)  
Stability limits (voltage stability limits, transient angle stability limit and dynamic angle stability limits).

The limiting condition of the transmission network can shift among thermal, voltage, and stability limits as the network operating conditions change over time. [9].

### 3. A Method for Transfer Capability based Marginal Power Flow Calculation

Depending upon the power market requirements, TTC might be calculated hourly, daily, or monthly. An accurate load forecast is very important for correct TTC calculation. Some effects such as unit commitment, maintenance, etc might be necessary to consider. Therefore it is very difficult to calculate TTC far from now in a large-scale power system. In this paper, only a present system operation condition is used for demonstrating TTC calculation. Here we assume system state estimation results are available and the operation point is stable and secure. Some assumptions are made in the paper for simplifying TTC calculation, the system has sufficiently large transient stability margin; hence it can survive the transient period and shift to a new steady state. Then the only stability constraint is voltage collapse at a critical point that can be solved for via continuation load

flow. The TTC calculation will be in the steady state analysis domain. [9].

#### 3.1 Mathematical Modeling

Power mismatch at each bus of the system can be expressed by the following quadratic function using bus voltages as state variables: [1,2,3,4,5]

$$P_k(X) = X^T A_k X + 2b_k^T X + C_k \quad (1)$$

Since the voltages and power are originally complex, in the above function we arrange the functions and variables as follows: When the subscript  $k$  is odd,  $P_k$  represents the real part, and  $P_k$  is imaginary for even  $k$ . The same rule applies to the voltage state variables. Matrix  $A_k$  is a sparse square matrix of  $2(n-1)$  dimension. ( $n$  is the number of total busses; one slack is assumed.) Non-zero elements of the matrix exist only where there are network connections.

The Voltage State that maximizes the following objective function determines the critical loading condition [2]

$$L = \sum P_{L,i} \quad (2)$$

Except for the bus active power (real part) included in the objective function, the following constraints are considered:

(a). Imaginary part of the bus included in (2)

Constant bus voltage

$$g_k = e_i^2 + f_i^2 - v_i^2 = 0 \quad (3)$$

Constant power factor

$$g_k = \tan \phi_i P_{L,i} - Q_{L,i} = 0 \quad (4)$$

(b). Constant incremental rate of load at specified load groups

Suppose  $v$  loads belong to a load group  $L_q$ . Using load distribution ratio  $\mu_{Lq,i}$  we can write the following equation:[2]

$$\frac{P_{Lq,1}}{\mu_{Lq,1}} = \frac{P_{Lq,2}}{\mu_{Lq,2}} = \dots = \frac{P_{Lq,i}}{\mu_{Lq,i}} = \dots = \frac{P_{Lq,v}}{\mu_{Lq,v}} = K_{Lq} \quad (5)$$

If one of the loads in the group, say  $P_{Lq,i}$  is added to the objective function, at the other load busses in the group we consider an additional constraint as below:

$$g_{Lq,i} = \mu_{Lq,i} P_{Lq,1} - \mu_{Lq,1} P_{Lq,i} = 0 \quad (6)$$

(c). Power balance condition at the other busses

For the busses that are not included in the objective function

(2), we consider power balance conditions, as in a regular power flow, for real and imaginary parts as follows:

$$g_k = P_k(X) = 0 \quad (7)$$

There is still an option, however, for these busses, whether the voltages are to be maintained, and active and reactive powers are kept constant or not.

### 3.2 Solution Algorithm

The constrained optimization problem defined by (2)-(7) can be converted to an unconstrained optimization using Lagrange multipliers [2], we get a multi-variable simultaneous nonlinear equation. Applying the Newton-Raphson method, with reasonable initial solution, we will obtain a fast iterative solution of the above problem. Operating point under heavy load condition of a power system will serve as a good initial solution. To obtain a present operating condition in the voltage state space, we solve the regular power flow calculation. For calculation of critical conditions, we may use the present operating point as an initial solution. If the present operating point is found lightly loaded, by the information of bus voltage angles, for example, we may heavy-load the power system for an initial condition. The procedure of the whole algorithm can be summarized as flow chart Fig.1.

### 4. Numerical Example

To evaluate the performance of the proposed algorithm, The IEEE14 bus test system is used to illustrate total transfer capability calculation. This system can give insight about TTC calculation implications and we can easily track and interpret factors influencing TTC although it is very simple. The system voltage lower and upper limits are taken as 0.95~1.05 p.u. For both a normal state and a critical state. Taking bus 1 as the source and bus 5, bus 4 the sink, the results of the system transfer capabilities in normal operation and critical operation are given in table 1. Bus 1 is taken to be the swing bus, at bus 5 and bus 4 increase until the critical state; the other busses assume the constrains conditions as in a regular load flow. The total transfer limits between points 1-5 as shown the table 1.

Table1. Transfer limit between points to points

| Configuration | Power transfer |                |
|---------------|----------------|----------------|
|               | Normal state   | Critical state |
| Line1-5       | 0.765-j0.027   | 4.631+j3.672   |
| Line2-4       | 0.559-j0.071   | 4.204+j1.189   |
| Line2-5       | 0.416-j0.070   | 3.371+j 1.420  |

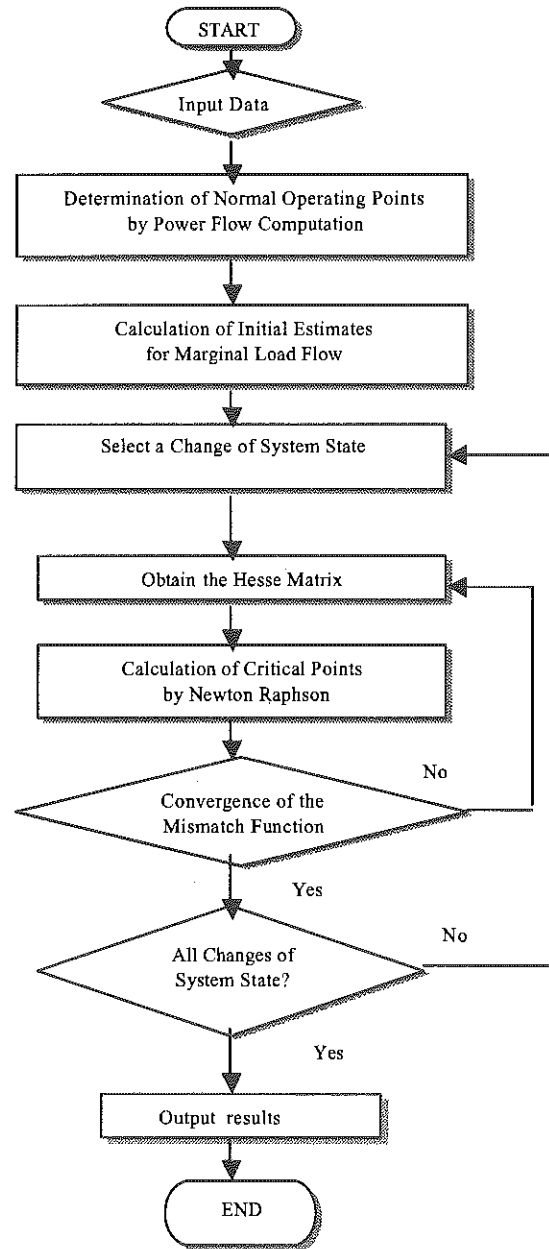


Fig. 1 Procedure of the Proposed Critical Power Flow

Convergence from an initial estimate to marginal power flow posed no particular problem. In most cases, the mismatch will reach  $10^{-6}$  to  $10^{-12}$  in a few iteration. The system has sufficiently large transient stability margin; hence it can survive the transient period and shift to a new steady state. Fig.2 shows P-V curve of load at 5 bus of IEEE14 Test System. Fig.3 shows P-V curve of load at 4 bus of IEEE14 Test System. There P-Vcurve are got at 3 times iteration by proposed method. In the same way, voltage, power factor,



and other condition can be flexibly specified as the test system. Then the only stability constraint is voltage collapse at a critical point that can be solved for via continuation load flow. The TTC calculation will be in the steady state analysis domain.

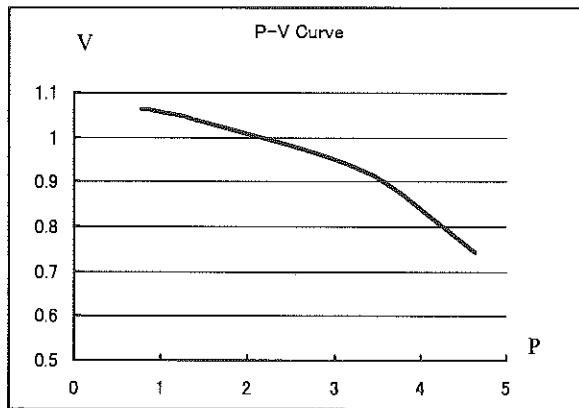


Fig. 2 P-V curve of load at 5 bus of IEEE 14 Test System

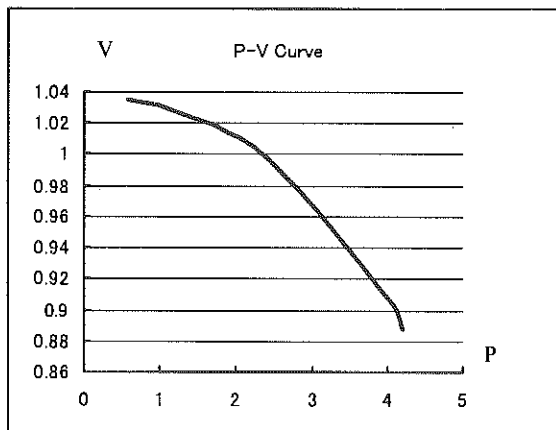


Fig. 3 P-V curve of load at 4 bus of IEEE 14 Test System

## 5. Conclusion

This paper has presented the Total Transfer Capability (TTC) calculation based on marginal power flow calculation, which maximizes the sum of load in a quadratic form under constraints derived from operating requirement and network constraints. The proposed procedure can increase all the loads simultaneously by a certain rate, or it can selectively increase an individual load or a specified group of loads by a certain rate. Voltage magnitudes, power factor, reactive power, and other conditions can be flexibly specified as the size of the target system increases, the dimension of Lagrangian grows substantially.

The proposed algorithm converges in little iteration when the

number of specified load buses is small, even if the size of the model, topology, and initial points are different. On the other hand, when the number of specified load buses is quite large (a thousand order), considerable iteration may be required to determine the initial search direction. However, once an approximate search direction is determined, the procedure converges rapidly.

A sample power system was used for the purpose of demonstration of the strategy. Results show that TTC is influenced by various factors and is very difficult to evaluate. The following consideration is using the further research.

In certain time frame, this is an on going process that will need refinement from time to time. TTC calculation should consider unit commitment, schedule, system transient stability limit etc. The important factor is that we should know as industry changes and new commission rulings warrant, it will audit its calculation methods for changes with Industry.

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## Discussions on Session IV: TRANSACTION EVALUATION & CONGESTION MANAGEMENT

### Part 1

**C. Vournas** (National Technical University of Athens): I have one question for Dr. Kobayashi: I'm very much interested in the way you compute the increase of capacity. Could you elaborate on which method you use, what criteria you use, so that you somehow get over the congestion?

**T. Kobayashi**: The system has great sensitivity of tap changer to the transferred capacity within the stability limit. The algorithm is included there, so only in linearized sense we calculate each tap change for each tap changer. Most effective tap changers are selected. If the tap changer is not sufficient, the second effective tap changer will be used.

**P. A. Lof** (ABB): I have a question for Professor Gross. Some of the charge used in your model is identified as an X, how are they related to the cost dollars? You're using congestion management. How are these congestive management costs related?

**G. Gross**: Those are basically the usage charges, which have to be paid by the IGO to the entities which are involved in removing congestion from the system. Those costs arise with the IGO from the incremental and decremental actions, which are provided either by the generators or by the loads. Those are typically small compared to the total costs, let's say, the system will endure in terms of meeting the demand charges. There are small changes about the current operating point.

**J. P. Paul** (EdF): I have a question concerning two papers about transactions and the way ISO accepted them, and find the solution for the constraint. I was surprised to see that in both of these papers you think ISO will always accept the transaction. Do we always accept the transaction and find the solution, for instance, by making modifications of the generation?

**G. Gross**: Let me give you an answer in terms of what we have experienced in the California system and the incremental, decremental actions taking on the California system. Basically those are preferred schedule we started with, the transactions will like to have the schedule implemented. Those schedules can not be effective until ISO has an opportunity to look at its feasibility. Basically what various players are bidding for are they really willing to endure the additional costs, which would be incurred, in making sure the transaction can be feasible. So basically that is an additional cost, and some of them maybe willing to pay that, some of

them may say that's too high a price. Now there could be, in addition, certain conditions that you state where maybe it's impossible to accommodate the transactions, and that may will happen. These are preferred schedules, and they have not yet been blessed with holy water, that yes, they can be undertaken in terms of next day. I'm looking basically in terms of forward market, so I'm not looking at taking of the transaction, say, for the next minute or the next hour.

**T. Kobayashi**: The Japanese deregulation is just beginning. The wheeling portion is very small. So the utility system operator is required to accept wheeling first. If wheeling volume increases, sometimes utility system operator rejects wheeling requests. In my system, if the power system can not maintain security using every action, the wheeling is rejected.

# An On-Line ATC Evaluation Tool for Large-Scale Power systems

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**Abstract** — A computer package developed for accurate determination of the Available Transfer Capability (ATC) of interconnected power systems with respect to a set of proposed power transactions is presented. A full AC nonlinear modeling of power systems including the effects of control devices is employed. To handle the static security constraints of credible contingencies, three look-ahead margin estimators for the load, thermal limit and voltage violation margins were developed and incorporated. This tool provides a list of the impact of the top most severe contingencies on the ATC, and the associated violated constraints. This tool also offer the platform for the development of a migration scheme to increase ATC. This tool was applied to compute the ATC satisfying the static security constraints of a 15,000-bus system with promising results.

## 1. Introduction

Open transmission access requires transmission network owners (or providers) to provide unbundled services (including ancillary services) necessary to support power transactions and to maintain reliable operation of transmission networks. To enforce the open transmission access policy, FERC defined the term 'available transfer capability' (ATC) to be posted in the OASIS to inform all energy market participants of the maximum power transfer capability for a power system. Hence, the ability to accurately determine on-line ATC is essential under the open access environment of power systems. A practical computer package for determining ATC will be an important tool for all transmission providers. Significant progress has been made in developing such a tool; however, one remaining major challenge is to accurately evaluate on-line ATC under varying loading conditions, taking into account the static as well as dynamic security limits of multiple contingencies [1,2].

In this paper, we describe the framework and methodology we used to develop an integrated computer package for analyzing and determining ATC with respect to proposed power transactions of interconnected power systems in the FERC's open-access transmission environment. This tool determines ATC subject to the following static as well as dynamic security constraints of credible contingencies:

- (1) line thermal limits
- (2) bus voltage limits
- (3) transmission corridor flow limits and MW reserves limits
- (4) steady-state stability limits
- (5) transient stability limits

We term the first three limits *soft limits*, because a power system can be operated under the violation of soft limits for a period. The last two limits are termed *hard limits*, since a power system instability occurs after either one of the hard limits is violated. We consider the preventive-mode ATC calculation as well as corrective-mode ATC calculation.

In order to effectively handle static security constraints of credible contingencies, three look-ahead load margin estimators for steady-state stability, line-thermal limit and voltage violation limit are developed and integrated into the tool. In order to effectively handle dynamic security constraints of credible contingencies, one look-ahead load margin estimators for transient stability limit is being developed and will be integrated into the tool.

The tool offers the following features:

### Functional viewpoint

- (1) It computes the ATC and identifies the corresponding (the most severe) contingency (including location and type of contingency), and the associated binding constraint (voltage violation, or thermal limit, or steady-state stability limit, or transient stability limit)
- (2) It identifies and ranks the top severe contingencies in terms of their impacts on ATC
- (3) For each ranked contingency, it computes the corresponding ATC and the associated binding constraint.
- (4) It pinpoints the system bottlenecks of ATC in terms of the locations of bottlenecks, types of binding constraint, and the associated binding contingency
- (5) It checks all the static security constraints of credible contingencies.
- (6) It checks all the static security constraints of credible contingencies.
- (7) It determines the required ancillary services.

### Modeling viewpoint

- (8) It uses a full AC nonlinear modeling
- (9) It takes the general characteristics of power system operating environments into account.
- (10) It includes the effects of control devices

### Control viewpoint

- (11) It allows the development of a migration scheme to increase ATC and FCITC
- (12) It provides a platform to take proactive action in evaluating ATC and FCITC and to prepare a remedy control, should a contingency occur.

### Probabilistic analysis

- (13) It allows a probabilistic treatment of each contingency and the associated risk management.

The current version of the tool can handle power system models up to 40,000 buses. It can accept power flow data files in the following formats: PTI (up to version 27), IEEE, EPRI, BPA and PECO. The tool has been applied to two realistic power system models; a 646-bus and a 15,000-bus power system to determine their ATC's with respect to several proposed power transactions under static security constraints of credible contingencies and the simulation results are promising. The tool can also determine the required

ancillary services such as VAR control and service components that facilitate power transfers.

## 2. Transfer Capability

Transfer capability refers to the ability of a transmission network to transfer electric power reliably from an area of supply to an area of demand by way of all transmission lines (or paths) between two areas under a given operating condition. The operating condition includes several projected factors such as the expected load demands, real generation dispatch policy, the system configuration, and the scheduled power transfers among the interconnected systems.

The transfer capabilities proposed by NERC are the first contingency incremental transfer capability (FCITC) or first contingency total transfer capability (FCTTC) for predicted peak load conditions. FCITC is the amount of electric power incremental above a normal base power that can be transferred in a reliable manner based on the following conditions [4]:

- (1) for the existing or planned system configuration, and with normal (pre-contingency) operating procedures in effect, all facility loadings are within normal ratings and all voltages are within normal limits,
- (2) the electric system is capable of absorbing the dynamic power swings, and remains stable following a disturbance that results in the loss of any single electric system element, such as a transmission line, transformer, or generation unit,
- (3) after the dynamic power swings subside following a disturbance that results in the loss of any single electric system element as described in (2) above, and after the operation of any automatic operating systems, but before any post-contingency operator-initiated system adjustments are implemented, all transmission facility loadings are within emergency ratings and all voltages are within limits.

Note that condition (1) is related to the static security constraints under the first contingency of the pre-contingency operating conditions while condition (3) is concerned with the static security constraints of the post-contingency operating conditions. Condition (2) is the typical (angle) transient stability constraint and may not include the voltage dip problem during transients as constraints. FCTTC is the total amount of electric power (net of normal base power transfers plus first contingency incremental transfers, i.e. the ATC) that can be transferred between two areas of the interconnected systems in a reliable manner based on conditions (1), (2), and (3) in the FCITC defined above.

Due to the nonlinear nature of interconnected electric systems, ATC's between two areas and their associated binding constraints depend on the system operating condition. The ATC's and their associated binding constraints can be significantly different for another system operating condition, such as a different pattern of system load demands, a different network configuration, or a different generation dispatch policy. Hence, ATC evaluations must be sufficient in system modeling and scope to ensure that all equipments as well as system

limits of the entire interconnected systems network are properly taken into account.

## 3. Transaction-dependent ATC

Given a set of proposed power transactions (and transmission service), the intent of calculating the transaction-dependent ATC is to calculate the maximum transfer capability (value) of the interconnected power system with respect to proposed power transactions, or simultaneous power transactions. The system model upon which the calculation is based must satisfy the following three conditions:

- (C1) it represents a realistic operating condition or expected future operating condition
- (C2) it conforms with the requirements of ATC definition
- (C3) it considers single contingency facility outages that result in conditions most restrictive to electric power transfers

The calculated transaction-dependent ATC can form the basis to approve or disapprove the proposed power transactions, or to suggest another transfer value for the proposed power transactions. One by-product of the developed tool for calculating the transaction-dependent ATC is the security margin after the proposed power transactions (or the suggested power transactions).

To achieve condition (C1), activation of control devices should be included in the system model. The control devices include: (i) Switchable shunts and static VAR compensators, (ii) ULTC Transformers, (iii) ULTC phase shifters, (iv) Static tap changer and phase shifters, (v) DC Network. In order to accurately simulate the actual power flow in the interconnected systems and the parallel power flows on adjacent systems, a detailed nonlinear power flow analysis of the interconnected system must be performed. To achieve condition (C2), it is important to accurately represent a proposed power transaction. Given a load demand vector (i.e. real and reactive load demands at each load bus) and a real generation vector (i.e. real power generation at each generator bus), one can compute the state of the power system (the complex voltage at each bus) by solving the set of power flow equations. Let  $P_i \equiv P_{gi} - P_{di}$  and  $Q_i \equiv Q_{gi} - Q_{di}$ . The lowercase  $g$  represents generation and the lowercase  $d$  represents load demand. The set of power flow equations can be represented in compact form as

$$f(x) \equiv \begin{bmatrix} P(x) - P \\ Q(x) - Q \end{bmatrix} = 0, \text{ where } x = (V, \theta) \quad (1)$$

where the vector  $P$  (resp.  $Q$ ) represents the real (resp. reactive) power injection at each bus.

Next, it will be explained how one can examine the power system steady-state behaviors under slowly varying loading and real power redispatch conditions. For example, if one needs to trace the power system state from the base-case load-generation condition specified by the following vector

$$[P_d^0, Q_d^0, P_g^0]$$

to a new load-generation condition specified by the following vector

$$[P_d^1, Q_d^1, P_g^1],$$

then one can parameterize the set of power flow equations as the following parameterized power flow equations

$$F(x, u, \lambda) \equiv f(x, u) - \lambda b = 0 \quad (2)$$

where  $u$  is the control vector and the load-generation vector  $b$  is

$$b \equiv \begin{bmatrix} P^1 - P^0 \\ Q^1 - Q^0 \end{bmatrix} \quad (3)$$

It is clear that the set of the parameterized power flow equations (2) become the base-case power flow equations when  $\lambda = 0$ ,

$$F(x, 0) = \begin{bmatrix} P(x) - P^0 \\ Q(x) - Q^0 \end{bmatrix} = 0$$

And when  $\lambda = 1$ , the set of parameterized power flow equations describes the power system steady-state behavior at the new load-generation condition  $[P_d^1, Q_d^1, P_g^1]$  and is described by

$$F(x, 1) \equiv f(x) - b = \begin{bmatrix} P(x) - P^1 \\ Q(x) - Q^1 \end{bmatrix} = 0$$

Thus, one can investigate the effects of varying real power generations as well as varying load demands on power system steady-state behaviors via solving the set of parameterized power flow equations (2). In fact, one can parameterize any change in PQ loads in conjunction with any change in P generations by selecting an appropriate vector  $b$ .

We next apply the above general setting to the problem of computing ATC of interconnected power systems. In this application, the vector  $b$  is used to represent one or several of the following power transactions and transmission service:

- Point-to-point MW transaction - the real power at one load bus of the receiving area varies while the others remain fixed and the real power at one generator bus of the sending area varies while the others remain fixed,
- Slice-of-the-system sale - both the real and reactive power demand at a load bus of the receiving area vary and the real power generation at some collection of generators of the sending bus varies while the others are fixed,
- Network service - the real and/or reactive power demands at some collection of load buses of the receiving area vary and the real power generation at some collection of generators of the sending bus varies while the others are fixed.

We shall call the vector  $b$  the proposed power transaction vector when the parameterized power flow equations (2) is used for ATC evaluation, and the scalar  $\lambda$ , the load-generation margin. The proposed power transaction vector  $b$  can be used to represent a power transaction involving simultaneous power transfers by summing each power transaction vector, i.e.  $b = \sum b_i$ ,  $i = 1, 2, \dots$  where the vector  $b_i$  represents the  $i$ th power transaction. The introduction of the power transaction vector and the load-generation margin enable us to evaluate ATC with respect to proposed multiple power

transactions of an interconnected power system satisfying the general characteristics (C1), (C2) and (C3) stated above.

#### 4. System Modeling

Electric power transfers between two control areas will be distributed among all parallel transmission paths according to the laws of physics. Power transfers cannot be forced through pre-determined transmission paths, unless the paths are physically controlled by control devices such as phase-shifters. To accurately compute ATC's, all the relevant physical constraints as well as engineering constraints must be modeled; hence, the power system model must take into account physical limitations on transmission lines and equipments/facilities, static security constraints such as thermal limits, voltage violation limits, and steady-state stability and dynamic security constraints. Moreover, a full AC detailed power system model including the sending area, the receiving area, as well as, all neighboring areas (to a less extent) is needed for accurate calculation of ATC.

The modeling capability of the developed tool includes:

##### 1. Generators

Generators are modeled as active and reactive power sources which also provide voltage control. The MVAR output of each on-line generator is adjusted during power flow solutions in order to control the voltage of the local bus (the bus where the generator is connected to) or a remote bus. The generator's MVAR output has fixed limits.

##### 2. Loads

Loads can be modeled as constant power (P-Q), constant current (I), or constant impedance (Z), or any linear combination of them. The tool can also accept nonlinear load models as long as they are expressed as nonlinear functions of voltage.

##### 3. Control Devices

The following control devices are modeled

- Switchable shunts and static VAR compensators
- Interchange schedules
- ULTC Transformers
- ULTC phase shifters
- Static tap changer and phase shifters

##### 4. DC Network

Given the following information:

- (1) a base case power system model with control devices, reactive power generation limits, real power generations due to participation factor, etc.
- (2) the current operating condition (obtained from the state estimator and the topological analyzer)
- (3) a set of proposed power transactions such as (i) a point-to-point MW transaction, or (ii) a slice-of-the-system sale, or (iii) a network service
- (4) a set of credible contingencies  $\{l_1, \dots, l_{total}\}$

the problem of ATC calculation can be mathematically stated as follows:

##### Preventive-mode ATC

$$\text{maximize } \lambda \quad (4)$$

subject to

(i) the parameterized power flow equations derived from information (1) - (3)

$$F(x, u, \lambda) \equiv f(x, u) - \lambda b = 0$$

(ii) soft limits of credible contingencies  $\{l_1, \dots, l_{total}\}$

- (1) line thermal limits
- (2) bus voltage limits
- (3) transmission corridor flow limits and MW reserves limits

(iii) hard limits of credible contingencies  $\{l_1, \dots, l_{total}\}$

- (4) steady-state stability limits
- (5) transient stability limits

the control allows the participation of generators, loads, ULTC taps, phase-shifter settings, shunt capacitors, and DC links as either active control or passive control to maximize simultaneous power transfer.

A violation of a hard limit will immediately result in system instability. Hence, preventive controls are essential for hard limits while timely corrective controls may prove appropriate soft limits.

#### Corrective-mode ATC

$$\text{maximize } \lambda \quad (5)$$

subject to

(i) the parameterized power flow equations derived from information (1) - (3)

$$F(x, u, \lambda) \equiv f(x, u) - \lambda b = 0$$

(ii) hard limits of credible contingencies  $\{l_1, \dots, l_{total}\}$

- (1) steady-state stability limits
- (2) transient stability limits

#### 5. Identify Critical Contingencies for Static Security

It is imperative in determining the ATC to take into account all credible contingencies. The strategy of using effective schemes to rank all credible contingencies and of applying detailed analysis programs only to critical contingencies is widely accepted [6-10]. In order to identify critical contingencies which will severely violate static security constraints, we developed three look-ahead ranking schemes which are to be incorporated into the tool.

The first look-ahead scheme ranks the set of all credible contingencies in terms of load margin to system collapse and to select the top few critical contingencies. The second look-ahead scheme ranks the set of all credible contingencies in terms of branch MVA violation and selects the top few critical contingencies. The third scheme ranks all credible contingencies in terms of bus voltage violation and selects the top few critical contingencies. Specifically, given (i) the current operating condition (obtained from the state estimator and the topological analyzer), (ii) a set of proposed power transactions, (iii) a list of credible contingencies, we develop the following three look-ahead schemes for estimating the load margins, along the proposed power transaction vector  $b$ , with respect to steady-state stability limit (nose-point load margin), bus voltage magnitude limit, line flow thermal limit, for the power system with the proposed power transac-

tions, i.e. the parameterized power system (parameterized along the direction of the proposed power transactions), subject to each contingency of the set of credible contingencies.

- (1) a nose-point load margin for each contingency, say  $\lambda_n$ , to measure the distance (in terms of MW and/or MVAR) from the current operating condition to the nose point of the parameterized power system subject to the contingency,
- (2) a voltage-limit load margin for each contingency, say  $\lambda_v$ , to measure the distance (in terms of MW and/or MVAR) to the state of the parameterized power system subject to the contingency at which the voltage constraint at some bus is violated,
- (3) a thermal-limit load margin for each contingency, say  $\lambda_t$ , to measure the distance (in terms of MW and/or MVAR) to the state of the parameterized power system subject to the contingency at which the thermal limit constraint of some transmission line is violated

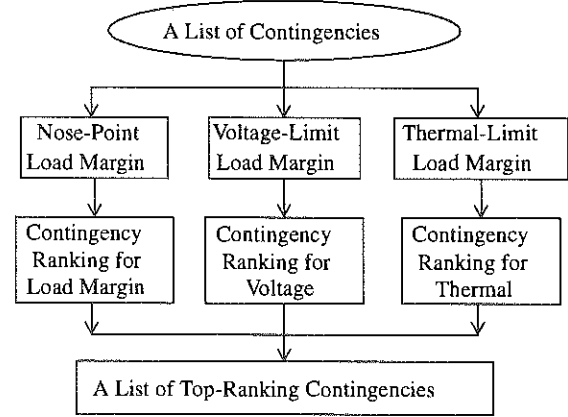


Figure 1 The proposed three schemes for ranking a list of contingencies in terms of load margin, voltage limit and thermal limit.

The look-ahead scheme for estimating the nose-point load margin and that for estimating voltage-violation load margin are based on the scheme developed in [5]. Let the  $\lambda - V$  curve of  $i$ -th load bus be chosen to derive the load margin. We then use the following quadratic curve

$$\lambda = \alpha + \beta V_i + \gamma V_i^2 \quad (6)$$

to approximate the  $V - \lambda$  curve of bus  $i$  passing through two points, say  $(V_{i,1}, \lambda_1)$  and  $(V_{i,2}, \lambda_2)$ . By using the information of the derivative  $\dot{V}_{i,2}$  at the second point, we can obtain the values for parameter  $\alpha, \beta$  and  $\gamma$  from following equations:

$$\begin{aligned} \lambda_1 &= \alpha + \beta V_{i,1} + \gamma V_{i,1}^2 \\ \lambda_2 &= \alpha + \beta V_{i,2} + \gamma V_{i,2}^2 \\ 1 &= \beta \dot{V}_{i,2} + 2\gamma \dot{V}_{i,2} V_{i,2} \end{aligned} \quad (7)$$

The point with the maximal value of  $\lambda$  on the curve (6) corresponds to the nose point, hence the corresponding value  $\lambda_{max}$  can be used to estimate the nose-point load margin. To estimate voltage-violation load margin, we consider a load bus, say bus  $j$ , and use  $\lambda_1, V_{j,1}, \lambda_2, V_{j,2}, \lambda_{max}$  and a characteristic equation to determine the corresponding quadratic

curve, and calculate the bus voltage at  $\tilde{\lambda}_{max}$ , denoted by  $V_{max,j}$ , in the following way

$$\lambda_1 = \alpha_j + \beta_j V_{j,1} + \gamma_j V_{j,1}^2 \quad (8)$$

$$\lambda_2 = \alpha_j + \beta_j V_{j,2} + \gamma_j V_{j,2}^2 \quad (9)$$

$$\tilde{\lambda}_{max} = \alpha_j + \beta_j V_{max,j} + \gamma_j V_{max,j}^2 \quad (10)$$

$$0 = \beta_j + 2\gamma_j V_{max,j} \quad (11)$$

The last equation, which is a characteristic equation for the nose point of the P-Q-V curve, states that the sensitivity of voltage with respect to load increase at the nose point is infinite. From the above four equations, one can obtain the values  $\alpha_j$ ,  $\beta_j$ ,  $\gamma_j$  and  $V_{max,j}$ . If the lower voltage, say  $V_j$ , of bus  $j$  is less than  $V_{max,j}$ , then the voltage-violation load margin of the bus equals the nose-point load margin of the bus. If the lower voltage  $V_j$  is higher than  $V_{max,j}$ , then the voltage-limit load margin,  $\lambda_v$  is derived from the following equation

$$\lambda_v = \text{minimum} \{ \alpha_j + \beta_j V_j + \gamma_j V_j^2 \} \text{ for all } j$$

In order to predict the point at which the power flow through a transmission line reaches its limit, one must look ahead at the behavior of line flow, which requires knowing the bus voltage magnitude as well as bus angle. This piece of information can be obtained from both  $\lambda-V$  and  $\lambda-\delta$  curves. In general, the  $\lambda-\delta$  curve is more complicated than the  $\lambda-V$  curve, especially for the portion that corresponds to the lower part of the  $\lambda-V$  curve. However, we observe that the upper part of the  $\lambda-\delta$  curve has a shape which is approximately either a straight line or a quadratic curve. Since we are only interested in the upper part of the  $\lambda-\delta$  curve, this piece of information is useful in the development of the following algorithm to obtain the  $\lambda-\delta$  curve.

To approximate the  $\lambda-\delta$  curve of bus  $i$ , suppose we have two points  $(\lambda_{i,1}, V_{i,1})$ ,  $(\lambda_{i,2}, V_{i,2})$  and the derivative  $\delta_{i,2}$  at the second point. We use the following guidelines:

(1) If the gradient  $\frac{\delta_{i,1} - \delta_{i,2}}{\lambda_1 - \lambda_2}$  is very close to  $\delta_{i,2}$ , then the curve  $\lambda-\delta$  is approximately a straight line which can be expressed as:

$$\delta_i = \frac{\delta_{i,1} - \delta_{i,2}}{\lambda_1 - \lambda_2} \lambda + \frac{\lambda_1 \delta_{i,2} - \lambda_2 \delta_{i,1}}{\lambda_1 - \lambda_2} \quad (12)$$

(2) Otherwise, the curve  $\lambda-\delta$  is approximately a quadratic curve which can be expressed as

$$\lambda = \alpha + \beta V_i + \gamma V_i^2 \quad (13)$$

The coefficient  $\alpha, \beta, \gamma$  can be obtained by solving the following equations

$$\begin{aligned} \lambda_1 &= \alpha + \beta \delta_{i,1} + \gamma \delta_{i,1}^2 \\ \lambda_2 &= \alpha + \beta \delta_{i,2} + \gamma \delta_{i,2}^2 \\ 1 &= \beta \delta_{i,2} + 2\gamma \delta_{i,2} \delta_{i,2} \end{aligned} \quad (14)$$

With the above formula, one can estimate the thermal-limit margin of a transmission line based on the  $\lambda-V$  and  $\lambda-\delta$  curves at end buses of the transmission line. Using this procedure for each transmission line, one can estimate the ther-

mal-limit load margin for the interconnected power system under the proposed power transactions. Recent developments of fast estimation of nose-point load margins appear, for example, in [12,13].

For evaluation of accuracy, we have applied the look-ahead margin estimators to a 646-bus power system and compared the results against those obtained by CPFLOW. We present partial results of numerical study below.

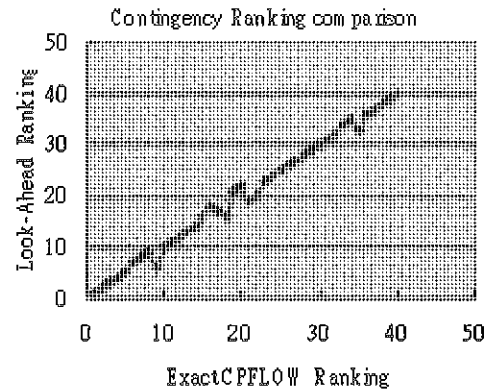


Figure 2 Contingency ranking comparison

Figure 2. gives the comparison between the exact contingency ranking and the ranking results by our look-ahead margin estimators. It can be seen that a perfect contingency ranking is obtained by our look-ahead margin estimator. The detailed results will be given in the section 8.

## 6. Identify Critical Contingencies for Dynamic Security

ATC of an interconnected power system with respect to a set of proposed power transactions can be constrained by dynamic security limit. The task of computing ATC subject to dynamic security constraints; however, is very challenging due to the nonlinear nature of interconnected power systems and the computation requirements for stability analysis of credible contingencies.

BCU limiter is a tool to quickly compute ATC limited by the dynamic security of credible contingencies. This tool is able to compute the amount of power transfers that a power system can withstand before its dynamic security limit is reached. In addition, BCU limiter can rank a given list of contingencies in terms of their load margins to dynamic security limits and compute the corresponding ATC.

BCU limiter is an integrated computer package of CPFLOW, BCU method, BCU classifiers and time-domain simulation. The combined BCU method and BCU classifiers, given an operating point, not only perform power system dynamic security assessments and ranking but also compute the margin to dynamic security limit for a list of contingencies [18,19].

## 7. Solution Algorithm

The four look-ahead ranking schemes, described in the previous two sections, for identifying critical contingencies for detailed studies by CPFLOW [11]. These detailed studies then provide, among the set of credible contingencies, top

binding contingencies, the associated binding constraints and, ultimately, the corresponding ATC's.

The solution algorithm for computing the ATC with respect to a set of proposed power transactions, i.e. transaction-dependent ATC, for an interconnected power system subject to static as well as dynamic security constraints is presented below. Note that even though these ranking schemes do not consider the physical limits of control devices, the solution algorithm does take these physical limits into account during the process of solving the parameterized power flow equations via CPFLOW [11] and BCU [18].

#### Stage 1: Initialization

**1.1** Build the power transfer vector  $b$  to represent (mathematically) the proposed power transfer transactions.

**1.2** Form the parameterized power flow equations by incorporating the power transfer vector  $b$  into the base-case power flow equations:  $f(x) - \lambda b = 0$

**1.3** Initialize the parameter, (i.e. load-generation condition number)  $\lambda$  by setting  $\lambda = 0$  to the base case.

#### Stage 2: Contingency Ranking for Static as well as Dynamic Security Violation

**2.1** Use a look-ahead scheme to rank the set of contingencies  $L$  in terms of branch MVA violation.

**2.2** Use a look-ahead scheme to rank the set of contingencies  $L$  in terms of bus voltage violation.

**2.3** Use a look-ahead scheme to rank the set of contingencies  $L$  in terms of load margin.

**2.4** Use a look-ahead scheme to rank the set of contingencies  $L$  in terms of load margin to transient instability

#### Stage 3: Compute first-contingency ATC and identify the corresponding binding contingency.

Select the top critical contingencies from each of the ranked contingencies obtained in Step 2.1 - 2.4; say the total number of contingencies is  $\mu$ . Apply the CPFLOW and BCU method to those contingencies for calculating the corresponding ATC.

#### Stage 4: Rank contingencies via the associated ATC

Rank the set of contingencies according to each value  $\hat{\lambda}_j$  obtained in Stage 3. Rename the set of contingencies and let the ranked contingency set be  $\hat{L} = \{l_1, l_2, \dots, l_\mu\}$  such that  $\hat{\lambda}_1 \geq \hat{\lambda}_2 \geq \dots \geq \hat{\lambda}_\mu$ . The ATC subject to static voltage stability constraints and static security constraints of the contingency set  $L$  is  $\hat{\lambda}_\mu$ , the binding contingency is  $l_\mu$  and the associated violated constraint is  $C^*$ .

#### Stage 5: (Output Analysis)

Output each ATC with respect to the corresponding binding contingency and the associated violated constraint.

We explain the physical meaning of the value  $\hat{\lambda}_j$  in Stage 4 which is the transaction-dependent ATC for the power system subject to the contingency, say  $j$ . Physically, if  $\hat{\lambda}_j$  is greater than 1.0, then it means that the transmission network is able to transfer the proposed power transactions, should the contingency  $j$  occur. In addition, the (normalized) static security margin of the power system with the proposed power transactions is  $\hat{\lambda}_j - 1.0$ . On the other hand, the transmission network is unable to transfer the proposed power transactions, should the contingency  $j$  occur, if  $\hat{\lambda}_j$  is less than 1.0. In this case, the suggested maximum value of reliable power transfer is  $\hat{\lambda}_j$  of the proposed power transac-

tions. For example, if  $\hat{\lambda}_j$  equals 0.7, then the maximum available transfer capability for the proposed power transactions is 70% of the proposed power transactions.

## 8. Numerical Studies

We have developed a computer package based on the solution algorithm presented in the previous section and on the platform of CPFLOW. The overall architecture of the computer package developed for evaluating maximum simultaneous transfer capability for a set of proposed power transactions and the required ancillary service of interconnected power systems in the FERC's open-access transmission environment is shown in Fig. 3.

### Preventive-mode ATC

We consider a 15005-bus interconnected power system containing about 2400 generators, 16,000 transmission lines, 8,000 loads, 4000 fixed transformers, 2400 fixed shunts, 3000 ULTC transformers, 800 switchable shunts, and other control devices such as fixed and ULTC phase shifters, etc. Given a base case of the interconnected power system with a secure operating point, a proposed power transaction described by transmitting 1300MW real power from area A to area B by decreasing all the real power generations of area B uniformly to zero (24 generators are scaled down to 0 MW) and increasing real power generations of area A uniformly to supply the loads of Area B (the area-wide generation of Area A is scaled properly), we apply the tool to evaluate the real power transfer capability from area A to area B of the interconnected power system subject to a list of contingencies which is a set of transmission line or generator outages. Three cutsets of 500KV transmission lines were selected and the corresponding sum of the line flows was defined as the interface line flows.

ATC can be expressed in several ways. It is sometimes useful to represent ATC in terms of pre-contingency interface power flow (i.e. the base-case interface power flow) at the limit point. In this numerical study, the ATC was constrained by one of the limitations: the nose point of the P-Q-V curve (steady-state stability limit), voltage-violation limit and thermal limit. The transient stability limit is not considered in this numerical study. ATC is expressed in terms of either (i) available power transfer between the sending area and the receiving area, or (ii) the pre-contingency power flow of the three interface flows.

The three fast look-ahead estimators were applied to the set of contingencies. The top 5 most serious contingencies captured by each look-ahead scheme and the corresponding load margin are listed respectively in Table 1, Table 2, Table 3. In these three tables, the contingency with \* is a generator trip. Since 4 of 15 contingencies are redundant, there are only 11 contingencies that require further study. The tool then performed detailed analysis based on the continuation power flow for each of these 11 contingencies to compute the ATC and to identify the corresponding binding constraints. Note that the participation of all control devices and the physical constraints of these control devices are taken into account in the process of continuation power flow study. The final results of ATC with respect to the proposed power transac-



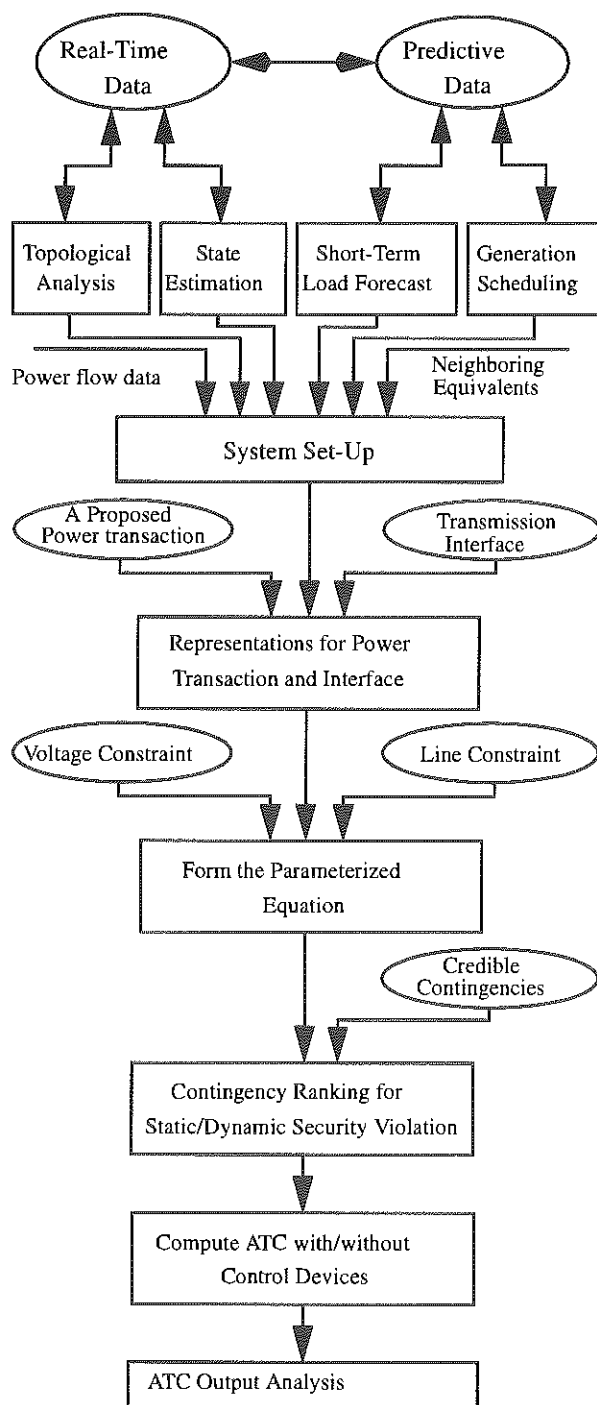


**Figure 3** The overall architecture of the tool developed for evaluating ATC.

tion along with a list of binding contingencies and the corresponding binding constraints are shown in Table 4.

**Table 1** The five most serious contingencies by load margin

| Contingency | Estimated Load margin (MW) | Estimated $\lambda_n$ |
|-------------|----------------------------|-----------------------|
| 32-6830     | 933                        | 0.728                 |
| 4364-6831   | 1043                       | 0.808                 |
| 85-4323     | 1053                       | 0.81                  |
| *4523       | 1053                       | 0.81                  |
| *4496       | 1057                       | 0.813                 |

It is clear that the ATC for the proposed power transaction, under the assumed set of contingencies, is 234MW between the sending area and the receiving area (instead of 1300 MW). The corresponding contingency (i.e. 89389-89392) is the binding contingency. Equivalently, the ATC of the proposed power transaction is 5422MW for the eastern interface, 2203MW for the central interface, and 4445MW for the western interface. It is interesting to note that the constrained eastern interface line flow under this contingency is the smallest among the constrained eastern interface line flows of all the contingencies considered. This is also true for the constrained central interface line flow and the constrained western interface line flow.

**Table 2** The five most serious contingencies by Thermal limit

| Contingency | Estimated margin (MW) | Estimated $\lambda_t$ |
|-------------|-----------------------|-----------------------|
| 89389-89392 | 194                   | 0.149                 |
| *289        | 566                   | 0.435                 |
| 89394-104   | 681                   | 0.524                 |
| *7498       | 746                   | 0.574                 |
| *89418      | 785                   | 0.604                 |

**Table 3** The five most serious contingencies by voltage violation

| Contingency | Estimated margin (MW) | Estimated $\lambda_v$ |
|-------------|-----------------------|-----------------------|
| 4364-6831   | 680                   | 0.523                 |
| 85-4323     | 748                   | 0.575                 |
| 32-6830     | 754                   | 0.58                  |
| *7498       | 759                   | 0.584                 |
| 89386-89387 | 759                   | 0.584                 |

| The top eight serious Contingency | Contingency | Pre-contingency Interface power flow of three interfaces (MW) |         |         | Corresponding ATC (MW) | Binding Constraints |                   |
|-----------------------------------|-------------|---------------------------------------------------------------|---------|---------|------------------------|---------------------|-------------------|
|                                   |             | Eastern                                                       | Central | Western |                        | Type                | location          |
| Base Case                         | Base Case   | 5552                                                          | 2247    | 4473    | 913                    | Thermal             | 7084              |
| The most serious                  | 89389-89392 | 5422                                                          | 2203    | 4445    | 234                    | Thermal             | 3687-3337         |
| 2nd most serious                  | 89394-104   | 5478                                                          | 2218    | 4452    | 584                    | Thermal             | 37-276 37-277     |
| 3rd most serious                  | 4364-6831   | 5531                                                          | 2237    | 4465    | 820                    | Voltage             | 6807, 6808, 7804  |
| 4th most serious                  | 32-6830     | 5537                                                          | 2240    | 4467    | 845                    | Voltage             | 6808, 68087, 7804 |
| 5th most serious                  | *7498       | 5538                                                          | 2241    | 4468    | 857                    | Thermal             | 37-276 37-277     |
| 6th most serious                  | 85-4323     | 5541                                                          | 2242    | 4468    | 869                    | Voltage             | 7804              |
| 7th most serious                  | *4496       | 5543                                                          | 2243    | 4469    | 883                    | Thermal             | 37-276, 37-277    |
| 8th most serious                  | 89386-89387 | 5549                                                          | 2246    | 4472    | 898                    | Thermal             | 37-276, 37-277    |

This tool can generate each ATC with the corresponding binding contingency as a by-product and the associated violated constraint in an 'increasing' order as shown in Table 4. This piece of information is useful for decision-making personnel to take a proactive approach to measure the transfer capability of the network. For instance, the ATC of the study system without the consideration of the contingency (89389-89392) is 584 MW. If the probability of the occurrence of contingency 89389-89392 is low, then it may be reasonable to post the ATC as 584 MW and, in the meantime, a remedy control scheme can be prepared in advance should contingency 89389-89392 occur. Likewise, the ATC of the study system without the consideration of contingencies 89389-89392 & 89394-104 is 820 MW. If the probability of the occurrence of either contingency 89389-89392 or 89394-104 is low, then it may be reasonable to post the ATC as 820MW and, in the meantime, a remedy control scheme can be prepared in advance should contingencies 89389-89392 and/or 89394-104 occur. It should be also pointed out that this tool also allows (established by Table 4) a probabilistic treatment of each contingency and the associated risk management.

#### Corrective-mode ATC

A Corrective-mode ATC is the maximal system ATC defined by system's hard limits such as steady-state stability limits and transient stability limits. A system can not be operated beyond its Corrective-mode ATC. Computing the Corrective-mode ATC is of a significant importance because it tells us the limits the a power system can reach without jeopardizing system's stability.

We have also applied the tool to evaluate the Corrective-mode ATCs subject to a list of credible contingencies on a 646 interconnected power system with a total generation of 28463MW. The scope of the tested system is: 98 Generators, 482 transmission lines, 224 loads, 489 ultc transformers and 158 switchable shunts. The proposed transaction is to transfer 254.5MW from central region to northern region by decreasing the generator 211 in the northern region to zero and increase the generator 1083 in the central region to support the load demand in the northern region. A cluster of 6 tie-lines between the two regions was monitored and the corresponding sum of the line flows was defined as interface line flows. The computed corrective-mode ATCs with the

corresponding binding contingencies is shown in the Table 5. This table also allows a probabilistic treatment of each contingency and the associated risk management as well.

Table 5 Contingency ranking for 600-bus system

| Ranking | Contingency | Interface power flow(MW) | ATC(MW) | Weakest bus |
|---------|-------------|--------------------------|---------|-------------|
| 1st     | 1500-1501   | 6526.66                  | 77.01   | 4214        |
| 2nd     | 1750-1900   | 6531.55                  | 77.01   | 4002        |
| 3rd     | 1750-1761   | 6549.36                  | 87.78   | 3243        |
| 4th     | 1750-1910   | 6537.02                  | 89.82   | 4410        |
| 5th     | 3321-3361   | 6506.09                  | 110.61  | 4410        |
| 6th     | 1900-2000   | 6533.99                  | 122.06  | 4410        |
| 7th     | 1700-1900   | 6517.43                  | 143.99  | 4410        |
| 8th     | 1910-2000   | 6519.14                  | 150.71  | 4410        |
|         | Base case   | 6499.90                  | 217.98  | 4214        |

## 9. Conclusion

In this paper, we have described a practical tool for analyzing and determining the ATC of an interconnected power system with respect to a set of proposed power transactions under static security constraints. This tool has comprehensive and full nonlinear modeling capability and can determine the maximum simultaneous transfer capability between any number of exporting and importing companies, zones, areas, or individual buses under various power transactions and transmission service. In order to effectively handle credible contingencies, the strategy of using effective schemes to rank all credible contingencies and of applying detailed analysis programs only to critical contingencies is adopted in the tool. We have developed three look-ahead margin estimators for estimating the load margin, thermal-limit margin and voltage-violation margin and integrated these three margin estimators into the tool. Hence, this tool has the ability to identify top binding contingencies, the associated binding constraints, and to compute the corresponding ATC subject to static security constraints.

We have applied this tool with promising results to compute the ATC with respect to a proposed power transaction considering static security constraints of a 15,000-bus power system. This tool identified the top eight binding contingencies, the associated binding constraints (some are thermal limit constraints and others are voltage violation constraints), and computed the corresponding ATC for each binding contingency, from which the system ATC is easily determined. Hence, this tool allows the development of a migration scheme to increase ATC and provides a platform to take a proactive action in evaluating ATC and to prepare a remedy control, should a contingency occur. It allows a probabilistic treatment of each contingency [14-17] and the associated risk management. This tool also provides a platform to take dynamic security constraints into account. Further development of this tool for computing ATC with both static and dynamic security constraints is being investigated.

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## An Improved Model for the Evaluation of Actual Transfer Capability in a Deregulated Environment

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### 1. Abstract

The Actual Transfer Capability (ATC) is important information in an open access operation of an electric power system. This paper presents an analytical method for the evaluation of ATC considering simultaneous power transactions including multilateral wheeling transactions and conventional utility-to-utility transactions. The method also provides the feasible operating region and the critical components that limit the ATC. The paper presents the mathematical model of the TRANSCO with multiple power transactions. An improved electric load model is used consisting of constant power, constant impedance and induction motor load. Circuit loading, bus voltage magnitude, and generated bus reactive power are considered as operating constraints. The actual transfer capability is computed with a successive linearization/optimization procedure. The linearization procedure is based on the powerful co-state method. The method provides the active operating constraints that limit the actual transfer capability. The method can be used in a Monte Carlo simulation to provide the Actual Transfer Capability over a variety of expected operating conditions.

**Keywords:** Actual Transfer Capability, Costate Method, Operating constraints, Power Wheeling Transaction, Wheeling effects, Sensitivity Analysis

### 2. Introduction

Recently, deregulation (or re-regulation) and open access are sweeping the whole country while many problems such as construction of competitive markets for ancillary services, parallel path flow, and physical transfer limits of transmission facilities must be better addressed. After Order 888 for transmission open access and Order 889 for the use of Open Access Same-time Information System (OASIS), Order no. 2000 for final rules on Regional Transmission Organization (RTO) was issued on December 20, 1999. Basically, Order 2000 requires each public utility owning, operating and controlling transmission facility to make certain filings with respect to forming and participating in an RTO. Order 2000 also specified the minimum characteristics and functions required for a transmission entity to be considered an RTO [1]. Recently, the California Independent System Operators submitted Amendment no. 13 to Federal Electric Regulatory Commission (FERC) [2]. California ISO tried to expand its Out-of-Market (OOM) authority in treating power imbalance problems and ancillary

services. The operational experience so far indicates that the ancillary services market is not performing well and ancillary services must be required from independent producers. Ancillary services have a profound effect on Actual Transfer Capability. Efforts are under way to develop better models that capture the interdependence of ancillary services and Actual Transfer Capability.

Power wheeling is defined as the power transmitted from a power producer to a consumer through transmission systems and distribution facilities of third parties [4]. Power wheeling can be considered within two frameworks, (a) wholesale (bulk) and (b) retail. Bulk wheeling is restricted within the transmission system only. Retail wheeling involves direct customer access [5], [6].

Since the transmission facilities have their physical limitation, not all of the power wheeling transaction can be accepted. Thermal limits of transmission facilities, voltage limits at each bus, reactive power constraints of generating units, and net interchange constraints do limit the feasibility of power transfers. The Actual Transfer Capability (ATC) is defined as the capability of the physical transmission network for additional power transfers over and above already committed use [9]. It is important to note that ATC is dependent upon the operating point of the system. Thus ATC computed at 8 am for a system may not be valid at 11 am of the same day for the same system. It is also important to note that contingencies limit the Actual Transfer Capability via two distinct mechanisms: (a) a contingency affects the steady state Transfer capability of the system (static) and (b) a contingency is always associated with some transients that limit the Power Transfer that can be operated securely (dynamic). ATC calculations are very important since the ATC has to be not only physically admissible but also commercially viable in the spot power market. A variety of methods and test results for ATC calculations have been reported in References [10-15]. In this paper, we present an improved method to calculate ATC. The method is based on a mathematically rigorous definition of power transactions and successive linearization and optimization of the Transfer Capability problem. An improved electric load model is also proposed. The formulation of the proposed method is described next in detail.

### 3. Problem Formulation

In this section, we present an improved model of multilateral power transactions, and the formulation of the Actual Transfer

Capability analysis problem. A linearization procedure of this problem is presented together with the solution procedure that is based on linear programming. A byproduct of the method is the feasible region of the Actual Transfer Capability.

Power wheeling transactions can be classified on the basis of the source and destination points. For example, bus-to-bus wheeling transaction is the transaction performed from single generator to single load, i.e. a wheeling provider located at a bus that provides power to a customer located at another bus. If a wheeling provider sells electric power to many customers at several locations, the wheeling transaction is named bus-to-area. Moreover, if a provider owns several generators at several buses and supplies energy to several customers at several buses, then the transaction is named area-to-area.

Depending on the source and destination, multilateral power wheeling transactions can be classified under the deregulated environment with the following categorization.

**Bus-to-Bus Power Wheeling Transactions:** A nonutility generator located at a bus may contract with single customer located at another bus. This is called a bilateral wheeling transaction. Mathematically, the transaction is described by the following set:

$$\{(w_1, v_1, (\gamma, P_w))\}$$

where  $w_1$  is the bus number of a wheeling provider,  $v_1$  is the bus number of a load,  $\gamma$  is incremental transmission loss for the transaction, and  $P_w$  is transacted real power.

**Bus-to-Area Power Wheeling Transactions:** A nonutility generator located at a single bus may contract with a specific power company that supplies a set of customers. The nonutility generator may be located in the same control area or in a different control area. Mathematically, the transaction is described with the following set:

$$\{(w_1, [(v_1, \rho_1), (v_2, \rho_2), \dots], (\gamma, P_w))\}$$

where  $\rho_k$  denotes a wheeling participation factor for the load at bus  $k$  and  $v$  is a vector for bus numbers where power consumers are connected, i.e.,  $v = [v_1, v_2, \dots, v_m]$ .

**Area-to-Area Power Wheeling Transactions:** Nonutility generators in an area may produce electric power to meet the demand of an area. This case can be modeled by expanding the concept of the bus-to-area wheeling transactions. Mathematically, the transaction is described with the following set:

$$\{[(w_1, p_1), (w_2, p_2), \dots], [(v_1, \rho_1), (v_2, \rho_2), \dots], (\gamma, P_w)\}$$

where  $p_k$  is a wheeling participation factor for the generator at bus  $k$ .  $w$  is a vector for bus numbers where power producers are connected, i.e.,  $w = [w_1, w_2, \dots, w_n]$ .

**Bus-to-System Power Wheeling Transactions:** A bus-to-system wheeling transaction is defined as a transaction from a nonutility generator to a system operated by an ISO. The ISO is assumed to operate a system consisting of two or more control

areas. This power wheeling transaction is typical of a spot power market. Mathematically, the transaction is described with the following set:

$$\{(w_1, [(v_1, \rho_1), (v_2, \rho_2), \dots], (\gamma, P_w))\}$$

The vector  $v$  is a set of bus number in a system, while the vector  $v$  for the case of bus-to-area transactions is a set of bus number in an area.

**Area-to-System Power Wheeling Transactions:** The notion of bus-to-area power wheeling transaction can be expanded to area-to-system power wheeling transactions.

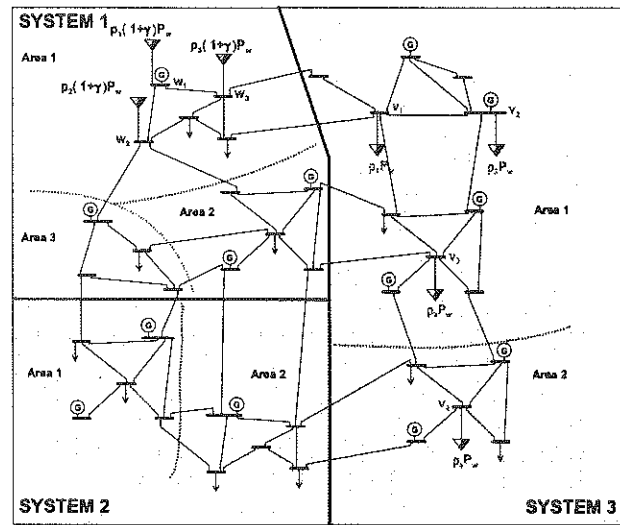


Figure 3.1 Area-to-System Power Wheeling Transaction

In this case, producers (nonutility or utility) with generating facilities at several buses of an area may bid to sell power to the system serving the total system load. Mathematically, the transaction is described with the following set:

$$\{[(w_1, p_1), (w_2, p_2), \dots], [(v_1, \rho_1), (v_2, \rho_2), \dots], (\gamma, P_w)\}$$

In summary and by comparing above mathematical descriptions, it can be concluded that all types of power wheeling transactions can be mathematically modeled with the following general expression:

$$\{(w, p), (v, \rho), (\gamma, P_w)\} = \{[(w_1, p_1), (w_2, p_2), \dots], [(v_1, \rho_1), (v_2, \rho_2), \dots], (\gamma, P_w)\}$$

where

$w$  is a vector for bus numbers where power producers are connected:  $w = [w_1, w_2, \dots, w_n]$ ,

$v$  is a vector for bus numbers where power consumers are connected:  $v = [v_1, v_2, \dots, v_m]$ ,

$p_k$  is a wheeling participation factor for the generator at bus  $k$ ,

$\rho_k$  is a wheeling participation factor for the load at bus  $k$ ,

$\gamma$  is an incremental loss for the transaction,

$P_w$  is the total real power of the transaction (load).

The factors,  $p$  and  $\rho$ , must satisfy the following equations:

$$\sum_{k=1}^n p_k = 1, \sum_{k=1}^m p_k = 1$$

In a deregulated environment, a producer may be responsible for transmission losses due to his transactions. There are many ways to compensate for transmission losses. One way is for the producer to provide additional generation to compensate for the losses in real time. This approach can be incorporated in the mathematical model by introducing the concept of incremental loss factor  $\gamma$ . In Figure 3.1, the loss factor,  $\gamma$ , is introduced for compensation of transmission losses. The quantity  $\gamma P_w$  represents transmission losses due to the wheeling transaction. Note that in the above model, if  $n = m = 1$ , then the model represents a bus-to-bus wheeling transaction, etc. Therefore, the model presented in this paper is general and can cover all types of power wheeling transactions.

### 3.1 Proposed Method for ATC Calculations

The ATC problem is formulated as an optimization problem that is described below:

$$\text{Max } \sum_n P_{wn}, \text{ for all wheeling transactions } n \quad (1)$$

$$\text{s.t. } \begin{aligned} |\tilde{S}_{km}| &\leq S_{km, \text{rate}}, \text{ for all circuits } km, \\ V_{k, \min} &\leq V_k \leq V_{k, \max}, \text{ for all buses } k, \\ Q_{gk, \min} &\leq Q_{gk} \leq Q_{gk, \max}, \text{ for all generation buses } k, \end{aligned}$$

where

$P_{wn}$  is real power wheeling transaction  $n$ ,

$|\tilde{S}_{km}|$  is circuit loading of the line connecting bus  $k$  and  $m$ ,

$S_{km, \text{rate}}$  is rated power at the line connecting bus  $k$  and  $m$ ,

$V_k$  is voltage magnitude at bus  $k$ ,

$Q_{gk}$  is reactive power generation at bus  $k$ .

The optimization problem is solved via successive linearization and linear programming, according to the flowchart of Figure 3.2. The linearization procedure of all constraints is based on the powerful co-state method applied to the specific model of power transactions. This method is described in the next section. The algorithm terminates when the optimality conditions are satisfied within a user specified tolerance.

### 3.2 Constraint Linearization via the Co-state Method

**Models Constraints:** The following system constraints are considered: (a) circuit loading, (b) bus voltage magnitude, and (c) generator reactive power. These constraints appear explicitly in the formulation of the problem (see previous section). Other constraints can be added if necessary. The system constraints are

written as a function of state variables and control variables as follows:

#### a) Circuit loading:

The power flow equations for circuit  $km$  are:

$$P_{km} = V_k^2 (g_{km} + g_{skm}) - V_k V_m \alpha_{km},$$

$$Q_{km} = -V_k^2 (b_{km} + b_{skm}) - V_k V_m \beta_{km},$$

where

$$\alpha_{km} = g_{km} \cos(\delta_k - \delta_m) + b_{km} \sin(\delta_k - \delta_m),$$

$$\beta_{km} = g_{km} \sin(\delta_k - \delta_m) - b_{km} \cos(\delta_k - \delta_m),$$

$g_{km}$  : transmission line conductance,

$b_{km}$  : transmission line susceptance,

$g_{skm}$  : transmission line  $\pi$ -equivalent shunt conductance,

$b_{skm}$  : transmission line  $\pi$ -equivalent shunt susceptance.

Therefore, the circuit loading from bus  $k$  to bus  $m$  is defined as:

$$F_{S_{km}} = |\tilde{S}_{km}|, \text{ for all } km \quad (2)$$

where

$$|\tilde{S}_{km}| = \sqrt{P_{km}^2 + Q_{km}^2}.$$

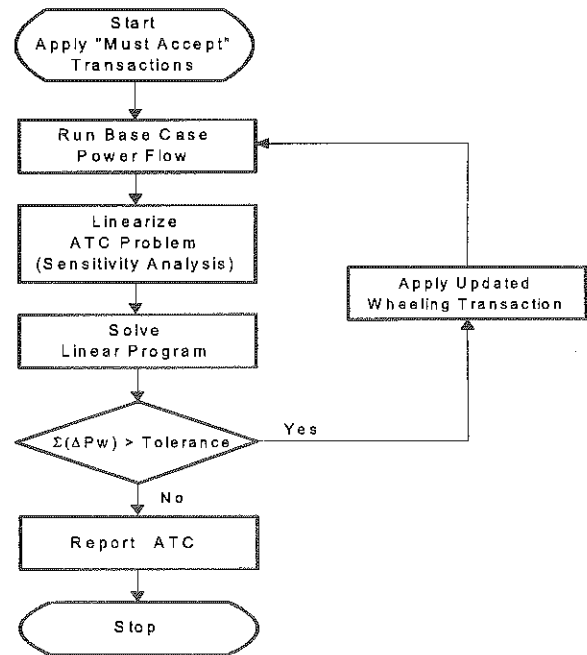


Figure 3.2 Flowchart of Proposed Method

#### b) Bus voltage magnitude:

Bus voltage magnitude at bus  $k$  is defined as:

$$F_{V_k} = V_k, \text{ for all bus } k \quad (3)$$

#### c) Generated bus reactive power:

Generated bus reactive power at bus  $k$  is derived as a function of state variables:

$$F_{Q_{gk}} = Q_{gk}, \text{ for all generation bus } k \quad (4)$$

where

$$Q_{gk} = -V_k^2 \sum_{m \in K(k)} (b_{km} + b_{skm}) - V_k \sum_{m \in K(k)} (V_m \beta_{km}) + Q_{dk},$$

$K(k)$ : the set of buses which share a circuit with bus  $k$ ,

$Q_{dk}$  is the reactive power load at bus  $k$ .

In order to linearize the selected constraints with respect to power wheeling transactions, the costate method is introduced [17], [18], [19]. The co-state method enables us to compute the linearized model of any performance metric with respect to any control variable at the present operating conditions.

**Co-state Method:** The linearization is performed at an operating point. Specifically, the power flow equations are written in terms of the system state and the power transactions, as follows:

**Real power flow equation**

$$g_{pk}(x, P_w) = \sum_{m \in K(k)} P_{km} - P_{gk} + P_{dk} - p_k(1+\gamma)P_w \delta(k-w_i) + p_k P_w \delta(k-w_j) \quad (5)$$

**Reactive power flow equation:**

$$g_{qk}(x, P_w) = \sum_{m \in K(k)} Q_{km} - Q_{gk} + Q_{dk} \quad (6)$$

where

$P_{gk}$  is the real power generation at bus  $k$ ,

$P_{dk}$  is the real power consumption at bus  $k$ .

Consider the system constraint  $F$ . The function  $F$  can be expressed in terms of the state variables,  $x$ , and the power wheeling control variable,  $P_w$ , i.e.,  $F(x, P_w)$ . The state variable,  $x$ , and the control variable,  $P_w$ , satisfy the power flow equations, (5) and (6). Differentiation of the function  $F(x, P_w)$  and the power flow equations  $g(x, P_w)$  with respect to  $P_w$  yields:

$$\frac{dF(x, P_w)}{dP_w} = \frac{\partial F}{\partial P_w} + \frac{\partial F}{\partial x} \frac{\partial x}{\partial P_w} \quad (7)$$

$$\frac{\partial g}{\partial P_w} + \frac{\partial g}{\partial x} \frac{\partial x}{\partial P_w} = 0 \quad (8)$$

By eliminating the derivatives,  $\frac{\partial x}{\partial P_w}$ , we obtain:

$$\frac{dF(x, P_w)}{dP_w} = \frac{\partial F}{\partial P_w} - \frac{\partial F}{\partial x} \left( \frac{\partial g}{\partial x} \right)^{-1} \frac{\partial x}{\partial P_w} \quad (9)$$

where

$\left( \frac{\partial g}{\partial x} \right)^{-1}$  is the inverse of jacobian matrix.

We introduce the costate vector  $\hat{x}^T$ , defined with:

$$\hat{x}^T = \frac{\partial F}{\partial x} \left( \frac{\partial g}{\partial x} \right)^{-1} \quad (10)$$

In terms of the costate vector  $\hat{x}^T$ , Equation (9) becomes:

$$\frac{dF(x, P_w)}{dP_w} = \frac{\partial F}{\partial P_w} - \hat{x}^T \frac{\partial g(x, P_w)}{\partial P_w} \quad (11)$$

where

$$\frac{\partial g_{pk}(x, P_w)}{\partial P_w} = -p_k(1+\gamma)\delta(k-w_k) + p_k\delta(k-v_k) = -e_{w_k} + e_{v_k} \quad (12)$$

$e_w$ : a vector with all zero entries except the elements corresponding to the positions of real power equation at buses in the vector,  $w$ :

$$e_w = (1+\gamma)[0 \cdots p_{w_1} \quad p_{w_2} \quad 0 \cdots p_{w_n} \cdots 0]^T,$$

$e_v$ : a vector with all entries zero except the elements corresponding to the positions of real power equation at buses in the vector,  $v$ :

$$e_v = [0 \cdots p_{v_1} \quad p_{v_2} \quad 0 \cdots p_{v_m} \cdots 0]^T.$$

Therefore, we need to know only the participation factors,  $p$  and  $\rho$ , in order to compute the sensitivity of system constraints with respect to power wheeling transactions. The participation factors are determined in the usual way from an economic dispatch solution. The factor,  $\gamma$ , can be determined by linearizing the transmission losses with respect to the power transactions [18]. It is important to note that the procedure for computing  $\gamma$  is also based on the co-state method.

The application of the co-state method to each of the three types of constraints is described below in a concise way.

**Circuit loading:**

Consider the circuit loading function, Equation (2). The linearization of this function is accomplished with direct application of equation (11). Since  $F_{S_{km}}$  is not explicitly dependent upon the variable  $P_w$  (power transaction variable), the partial derivative below is zero, i.e.:

$$\frac{\partial F_{S_{km}}}{\partial P_w} = 0.$$

The co-state vector is computed with equation (10). The jacobian matrix is computed at the operating point. The components of the

vector  $\frac{\partial F_{S_{km}}}{\partial x}$  are written as follows:

$$\begin{aligned} \frac{\partial |S_{km}|}{\partial \delta_k} &= \frac{1}{2|S_{km}|} \left\{ 2(V_k^2 (g_{km} + g_{skm}) - V_k V_m \alpha_{km})(V_k V_m \beta_{km}) \right. \\ &\quad \left. + 2(V_k^2 (b_{km} + b_{skm}) + V_k V_m \beta_{km})(V_k V_m \alpha_{km}) \right\} \\ \frac{\partial |S_{km}|}{\partial \delta_m} &= \frac{1}{2|S_{km}|} \left\{ 2(V_k^2 (g_{km} + g_{skm}) - V_k V_m \alpha_{km})(-V_k V_m \beta_{km}) \right. \\ &\quad \left. + 2(V_k^2 (b_{km} + b_{skm}) + V_k V_m \beta_{km})(-V_k V_m \alpha_{km}) \right\} \\ \frac{\partial |S_{km}|}{\partial V_k} &= \frac{1}{2|S_{km}|} \left\{ 2(V_k^2 (g_{km} + g_{skm}) - V_k V_m \alpha_{km})(2V_k (g_{km} + g_{skm}) - V_m \alpha_{km}) \right. \\ &\quad \left. + 2(V_k^2 (b_{km} + b_{skm}) + V_k V_m \beta_{km})(2V_k (b_{km} + b_{skm}) + V_m \beta_{km}) \right\} \\ \frac{\partial |S_{km}|}{\partial V_m} &= \frac{1}{2|S_{km}|} \left\{ 2(V_k^2 (g_{km} + g_{skm}) - V_k V_m \alpha_{km})(-V_k \alpha_{km}) \right. \\ &\quad \left. + 2(V_k^2 (b_{km} + b_{skm}) + V_k V_m \beta_{km})(V_k \beta_{km}) \right\} \end{aligned}$$

Thus, the co-state vector is determined by matrix multiplication of the inverse of the jacobian matrix and  $\frac{\partial F_{s_{km}}}{\partial x}$ . The last component,  $\frac{\partial g_{pk}(x, P_w)}{\partial P_w}$ , is described in Equation (12).

#### Bus voltage magnitude:

Consider the bus voltage magnitude at bus  $k$ . Since the voltage magnitude is not an explicit function of the power transaction variable, it follows:

$$\frac{\partial F_{V_k}}{\partial P_w} = 0$$

The derivatives of bus voltage magnitude with respect to state vector  $x$  can be simply derived as follows:

$$\frac{\partial F_{V_k}}{\partial \delta_k} = 0, \quad \frac{\partial F_{V_k}}{\partial \delta_m} = 0, \quad \frac{\partial F_{V_k}}{\partial V_k} = 1, \quad \frac{\partial F_{V_k}}{\partial V_m} = 0$$

For this case, the co-state vector is determined by matrix multiplication of the inverse of the jacobian matrix and the derivative of the voltage magnitude with respect to the state vector  $x$ . Finally, Equation (12) is applied to compute the sensitivity.

#### Generated bus reactive power:

Consider the generated bus reactive power at a generating bus  $k$ . Similarly, as for the other model constraints, the following holds:

$$\frac{\partial F_{Q_{gk}}}{\partial P_w} = 0.$$

For the computation of the derivative of the reactive power generation at bus  $k$ , with respect to the system state, we first express the generated reactive power as a function of the system state:

$$Q_{gk} = \sum_{m \in K(k)} Q_{km} + Q_{dk}$$

Therefore, the derivatives of the reactive power generation with respect to the state vector  $x$  are as follows:

$$\frac{\partial Q_{gk}}{\partial x} = \sum_{m \in K(k)} \frac{\partial Q_{km}}{\partial x}$$

where

$$\frac{\partial Q_{km}}{\partial \delta_k} = -V_k V_m \alpha_{km},$$

$$\frac{\partial Q_{km}}{\partial \delta_m} = V_k V_m \alpha_{km},$$

$$\frac{\partial Q_{km}}{\partial V_k} = -2(b_{km} + b_{skm})V_k - V_m \beta_{km},$$

$$\frac{\partial Q_{km}}{\partial V_m} = -V_k \beta_{km}.$$

Also, Equation (12) is applied to this sensitivity analysis.

The advantage of the co-state method is that the co-state vector needs to be computed only once. The computational effort for the co-state vector requires one forward and one back substitution on

the vector  $\frac{\partial F(x, P_w)}{\partial x}$  which is quite sparse. The remaining computations are trivial in terms of computational effort. These observations are enough to illustrate the efficiency of the method.

## 4. Application Examples

In this section, we present the application of the method on two example test systems. We consider several simultaneous power transactions. The method also provides the feasible ATC regions for various operating conditions.

**Example Test System 1:** The example power system 1 comprises two areas, i.e., area 1 and area 2. Area 1 includes buses 1, 3 and 4, and area 2 includes only bus 2. The two areas are interconnected via two tie lines. The locations of the meters on the tie lines indicate the boundary between the two areas. Table 4.1 and Table 4.2 describe the system parameters. The load at bus2 is 12.5MW + j 2.5Mvar, the load at bus3 is 25MW + j7.5Mvar, and the load at bus 4 is 50MW + j10Mvar.

There are two independent generators at bus1 and bus2 and two independent customers at bus3 and bus4. The two independent generators have two independent contractual agreements with the independent customers at bus3 and bus4.  $P_{w1}$  is a power wheeling transaction from bus1 to bus4.  $P_{w3}$  is a power wheeling transaction from bus 3 to bus 4. The power wheeling transactions are modeled as two independent bus-to-bus power transactions. Therefore, there are two control variables,  $P_{w1}$  and  $P_{w3}$ . These power transactions are modeled as follows:

$$\text{Transaction 1: } \{(w_1, p_1), (v_4, p_4), (\gamma, P_{w1})\}$$

$$\text{Transaction 2: } \{(w_3, p_3), (v_4, p_4), (\gamma, P_{w3})\}$$

where

$$p_1, p_3, \text{ and } p_4 \text{ are equal to one.}$$

The power transactions are symbolically represented in Figure 4.1. The proposed method is applied to the given example power system. The linearized system constraints are utilized by the optimization problem to determine the ATC. Figure 4.2 illustrates the feasible region of the optimization problem on the first iteration. At the initial operating point, i.e., at  $P_{w1} = 0.0$  and  $P_{w3} = 0.0$ , the feasible region is bounded with three extreme points:

$$(P_{w1}, P_{w3}) = \{ (0.0, 0.0), (0.0, 4.82669), (2.01968, 0.0) \} \quad (13)$$

The optimal solution is given with the point  $(P_{w1}, P_{w3}) = (0.0, 4.82669)$ . Dotted straight lines represent the linearized system constraints at the first iteration. The feasible region as defined with the linearized constraints is not accurate. In fact, the optimal point  $(0.0, 4.82669)$  is infeasible. To obtain a better approximation of the feasible region, we use a "continuation method". Specifically, we increase the power transactions to levels close to the optimal point and repeat the calculations. In this test system,  $P_{w3}$  is increased to 2.0 and the computations are repeated. At this point, the critical transmission-loading



constraints are the lines 2-4 and 3-4. The shaded region in Figure 4.2 is the new feasible region. This “continuation” type method can continue to provide a very good approximation of the feasible region. Figure 4.3 provides another ATC calculation at another operating point i.e.,  $P_{w1}=1.0$  and  $P_{w3}=1.0$ . It is important to note that this method can be extended to multiple power transactions but the results will not be amenable to graphical representation.

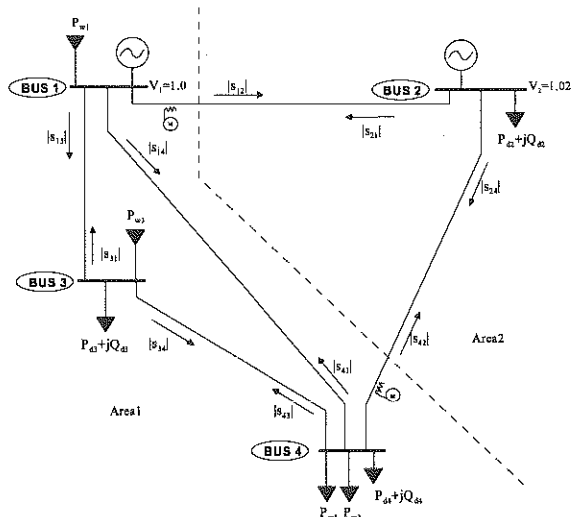


Figure 4.1 Example Test Power System

Table 4.1 Branch Data

| From Bus | To Bus | R (pu) | X (pu) | Rates (MVA) |
|----------|--------|--------|--------|-------------|
| 1        | 2      | 0.0990 | 0.9901 | 51.0102     |
| 1        | 3      | 0.0103 | 0.0821 | 144.7214    |
| 1        | 4      | 0.0099 | 0.0990 | 134.6410    |
| 2        | 4      | 0.0099 | 0.0990 | 134.6410    |
| 3        | 4      | 0.0053 | 0.0662 | 156.5685    |

Table 4.2. Generator Data

| Bus No. | $P_{max}$ | $P_{min}$ | $Q_{max}$ | $Q_{min}$ |
|---------|-----------|-----------|-----------|-----------|
| 1       | 500 MW    | 0 MW      | 75MVar    | -50Mvar   |
| 2       | 150 MW    | 0 MW      | 50MVar    | -30MVar   |

## 5. Summary and Conclusions

This paper has discussed a powerful method for the evaluation of the ATC calculation, which is a critical issue in the deregulated power industry with emphasis on simultaneous multilateral power wheeling transactions. The method provides the feasible region of the transactions. The method and results in this paper exactly meet the demand of Order 2000, that is, the ATC calculation considering simultaneous power wheeling

transactions. The method is also extremely efficient and applicable to large scale power systems.

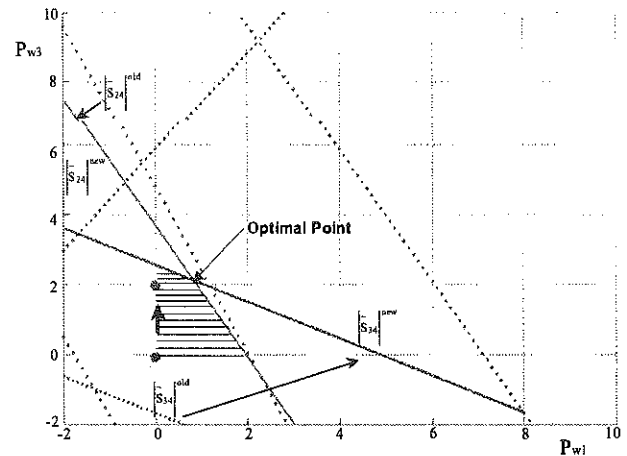
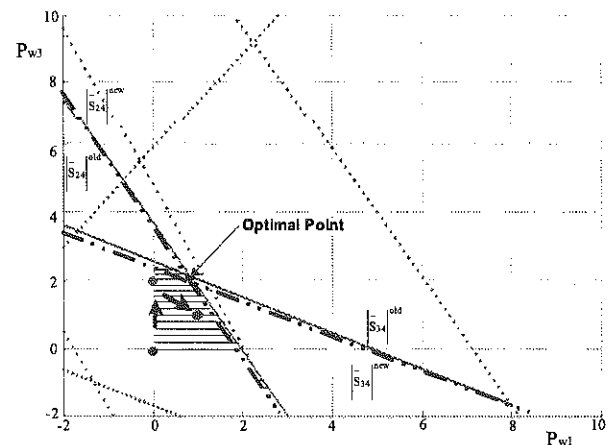


Figure 4.2 Graphical Illustration of Constraints and Feasible Set for  $P_{w1}=0.0$  and  $P_{w3}=2.0$



where

— · · — : critical constraints for the new transactions.

Figure 4.3 Graphical Illustration of Constraints and Feasible Set for  $P_{w1}=1.0$  and  $P_{w3}=1.0$

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## 7. Biographies

**A. P. Sakis Meliopoulos** (M '76, SM '83, F '93) was born in Katerini, Greece, in 1949. He received the M.E. and EE diploma from the National Technical University of Athens, Greece, in 1972 and the M.S.E.E. and PH.D. degrees from the Georgia Institute of Technology in 1974 and 1976, respectively. In 1971, he worked for Western Electric in Atlanta, Georgia. In 1976 he joined the Faculty of Electrical Engineering, Georgia Institute of Technology, where he is presently a professor. He is active in teaching and research in the general modeling, analysis, and control of power systems. He has made significant contributions to power system grounding, harmonics, and reliability assessment of power systems. He is the author of the books, *Power Systems Grounding and Transients*, Marcel Dekker, June 1988, *Lightning and Overvoltage Protection*, Section 27, *Standard Handbook for Electrical Engineers*, McGraw Hill, 1993, and the monograph, *Numerical Solution Methods of Algebraic Equations*, EPRI monograph series. Dr. Meliopoulos is a member of the Hellenic Society of Professional Engineering and the Sigma Xi.

**Sun Wook Kang** (M '99) is a graduate student at Georgia Institute of Technology, Atlanta, Georgia. He has received B.S.E.E. at the School of Electrical Engineering in Chonbuk National University, Chonju, South Korea in 1997 and M.S.E.E. at the School of Electric and Computer Engineering in Georgia Institute of Technology in 1999. His research interest is in the power system reliability, security and analysis in a deregulated environment.

## Estimating System Collapse in Static Linear ATC

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### Abstract

This paper describes a method to incorporate the supervision of collapse in the framework of static linear ATC. This is achieved by monitoring the margin to the Static Transfer Stability Limit (STSL) of individual transmission lines. For a given parameter space, collapse will occur further away and close to the point where the complex flow of a line reaches its STSL.

We first estimate the STSL for all lines and determine corresponding line active power flow margins. Then we use Power Transfer Distribution Factors (PTDF's) to find estimates of the system's margin to collapse. Numerical examples illustrate this method and the results may suggest its incorporation to filter non-critical cases in linear security analysis functions.

**Keywords:** ATC, PTDF, STSL, Static Collapse.

### Introduction

Static collapse occurs in power systems when a parameter changes in a certain direction until the solution to the power flow equations ceases to exist. The phenomenon appears through several mechanisms but is more likely to occur in stressed systems with low voltages and large flows of reactive power. Both static and dynamic collapse have been extensively described in the literature and computational method for its determination are well established [1,3].

Collapse is a matter of concern among the power system community as deregulated operation practices may drive interconnected power systems to uncommon states [4-6]. In order to avoid collapse problems security analysis functions such as Contingency Analysis and Available Transfer Capability (ATC) must assess proximity to collapse for every short and long run planning and operating scenarios. Security constrained optimization routines such as Optimal Power Flow (OPF) also have to include collapse supervision, which generally is presented as the value of a margin to the point of collapse in a given parameter space.

There are three basic methods to determine the margin to collapse: a) Sequential power flow, b) Continuation methods, and c) Energy methods. Although all these are exact methods, their computational requirements make them prohibitive for studies such as ATC, when the number of buses, contingencies and specified directions is large. For instance, an ATC study involving hundreds of directions, thousands of contingencies and monitored elements, may take several days if a continuation power flow is performed for each contingency and each transfer. Furthermore, the nature of ATC requires a new complete computation once any transaction is implemented [7]. The design of fast algorithms suitable for such applications remains a challenge in power engineering and deregulated operations.

In this paper, we propose an estimation method for proximity to collapse, which can be directly incorporated in linear security functions. The method is based on the parametric necessary condition described in reference [8]. For a given parameter space, this condition occurs close to (and before) the point of collapse. This allows us to use it instead of the actual collapse point to derive a system margin. The same reference demonstrates that this is a good approximation.

The proposed method assigns limits known as Static Transfer Stability Limits (STSL's) to the sending and receiving ends of individual transmission lines. These limits provide feasibility intervals for the flow of active power in a line. The STSL's are obtained by extrapolating the transmission line complex flow trajectory using operating point dependent power circle diagrams and sensitivity information from the base case power flow Jacobian. The method disregards discrete controls, such as tap changer and capacitor connection, but considers voltage regulation and reactive generation limits. The necessary variation in the parameter space to make a line reach one of these limits is found using linear techniques, based on Power Transfer Distribution Factors (PTDF's). The margin to collapse is estimated directly using this method.

The remainder of this paper is organized as follows: The first section describes the necessary condition for non-existence of solution. This is followed by a description of the

computation of transmission line STSL's. Estimation of the margin to collapse is presented with numerical results. Finally, the paper suggests the extension of this method to linear security functions and provides several conclusions.

### Necessary Condition for Collapse

Let us consider a power system with a power flow solution for a parameter value  $p=p^0$ . This parameter may correspond to system active power load or the magnitude of a transfer in a specific direction, i.e.,  $p$  embeds source and sink participation factors. When we increase  $p$  in a certain direction, the flows in the system vary up to a point where some limit is hit. Limits of interest include line thermal limits, voltage constraints, system collapse, or other operational constraint such as flow-gate capability. Transient stability limits will also be affected when  $p$  changes.

Let us assume that at  $p=0$  no limit violation occurs in the base case. In general, we need also that the system be secure when a set of plausible contingencies takes effect, i.e., for any contingency in the set, the post-contingency operating point does not violate any of these security constraints. For clarity, we do not consider contingency analysis in this paper.

Thus, in the case of static collapse, we want to determine a value of the parameter  $p=p^*$ , which will make the system cease to have a mathematical solution. A solution will exist in the interval  $[0, p^*)$ , and there will not be a solution for  $p$  in the interval  $[p^*, +\infty)$ . It is known [2,3] that  $p^*$  corresponds to the condition of singularity of the power flow Jacobian and this point is called "the point of static collapse". There are several mechanisms for static collapse, but we tend to think of collapse as a depletion of bus voltages. However, it is not difficult to show that collapse can also occur when voltages are good, or even with perfect voltage control and unlimited reactive power support. In such a case, the mechanism for collapse is due to the transmission capability of the network. We explain all this with a simple example.

Consider an elementary 2-bus system, where bus 1 is the slack and bus 2 is a *PV*-bus. The load at bus 2 is purely real. The generators at both buses have unlimited reactive power resources. The transmission line is lossless and voltages are regulated at 1 p.u. Starting with an initial condition in which the load is 0 MW, we increase the transfer from bus 1 to bus 2. We may think of this example as generator 1 selling power to generator 2 because generator 1 is cheaper. As the transfer increases, the trajectories of the transmission line complex power flow at end 1 and end 2 of the transmission line are as shown in Figure 1. The sending end complex flow follows the trajectory from point  $A$  to point  $B$ . The receiving end has the trajectory from  $A$  to  $B'$ . These trajectories follow the power circle diagram [2] of line 1-2. Power circle diagrams are defined for given voltages, and in this case the trajectories are perfect circles due to the perfect voltage

control. The centers and radii of these circles depend only on the parameters of the transmission line, and the voltages at buses 1 and 2. Note that if we knew  $P_{12}$  for a certain operating point, we can immediately obtain the reactive power flow  $Q_{12}$ .

Let us increase the transfer from bus 1 to 2 up to point  $B$ . This corresponds to a transfer of  $P_{12}^B$  MW. As this is a lossless case and all the power delivered to the load has to come through the line, it is clear that the Power Transfer Distribution Factor (PTDF) for this transfer is always equal to minus one (MW flow per MW injection). If we increase the load by one additional MW, we would be imposing a line flow  $P_{12} = P_{12}^B + 1 > P_{12}^B$ . This is not possible because the power circle diagram forces the trajectory to be vertical at that point. The additional injection would make the system collapse even with perfect voltages and enough reactive power support. Therefore, the trajectory of the complex power flow of the line has created a bound for the transfer.

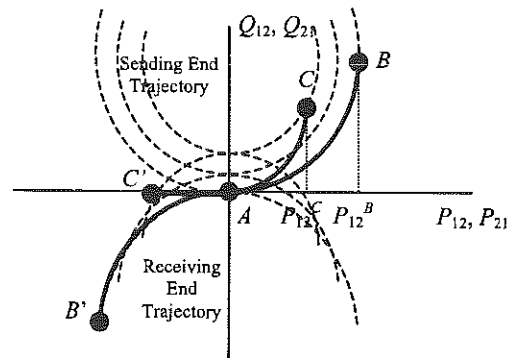


Figure 1: Complex Flow Trajectories

When voltages in the system vary, the power circle diagrams become operating point dependent. A reduction in the voltage of the receiving bus makes the circle diagram shrink keeping the same center. A reduction of the receiving end bus voltage makes the receiving end circle go up and shrink as illustrated in the Figure.

Suppose that in our example there is no reactive power support at bus 2. Then when the load at bus 2 increases, the voltage at bus 2 decreases and the trajectory of the complex flow at the sending end is as from point  $A$  to point  $C$ , and the trajectory at the receiving end is as from point  $A$  to  $C'$ . The maximum feasible transfer of power from 1 to 2 now corresponds to  $P_{12}^C$ . In general, every line in a system will have a corresponding trajectory for a certain topology, set of applied controls and value of a transfer. We call the point where the trajectory becomes vertical the Static Transfer Stability Limit (STSL) of a line end. For a line end we define the STSL interval as the MW range for which the trajectory of the line is not vertical.

The necessary condition given in [8] states that if we start with a value of a parameter  $p^0$ , which results in a power flow solution with line flows  $P_{jk}^0(p^0)$  feasible with respect to STSL's, and we increase the parameter until the point of system collapse, e.g., at point  $p=p^*$ , then there is a value of the parameter  $p^0 < p^C < p^*$ , such that no line has reached its STLS for  $p^0 < p < p^C$ , and at least one line violates its STLS for  $p^C \leq p < p^*$ . Furthermore, the value of  $p^C$  is close to the value of  $p^*$ .

Thus, in this paper we look for the value of  $p^C$ , which we call "the point of STSL", instead of  $p^*$ , which is the actual point of collapse. Reference [8] shows that this approximation results in an error in the order of 5-8%. We note that even if voltages vary the trajectories of the complex flow are smooth with respect to active power. We will assume that those trajectories are also circles, whose parameters are unknown.

### Estimation of STSL's

In this section we present a method to estimate STSL's. Let us first assume that the system has very good voltages and we are confident that there are enough var resources to keep good voltages across the system. This allows us to assume that voltages are kept nearly constant from the base case. This set of values can be used for example when we want to monitor flowgate conditions and we know that the voltage support is good.

With constant voltages, the STSL's are computed directly from the power circle diagram. The equation of the sending end circle diagram of line  $j-k$  is [10]:

$$(P_{jk} - V_j^2 G_{jk})^2 + (Q_{jk} + V_j^2 B_{jj} + V_j^2 B_{jk})^2 = (V_j V_k Y_{jk})^2 \quad (1)$$

Where the line admittance is  $\bar{Y}_{jk} = G_{jk} + jB_{jk}$  and  $B_{jj}$  accounts for half of the line charging. In this circle, the center coordinates and the radius are given by:

$$(P_{jk0}, Q_{jk0}) = (V_j^2 G_{jk}, -V_j^2 [B_{jj} + B_{jk}]) \quad (2)$$

$$S_{jk0} = V_j V_k Y_{jk} \quad (3)$$

In such a circle, the verticality condition of the trajectory occurs at a point with coordinates:

$$(P_{jk}^{\max, st}, Q_{jk}^{\max, st}) = (V_j^2 G_{jk} + V_j V_k Y_{jk}, -V_j^2 [B_{jj} + B_{jk}]) \quad (4)$$

Therefore, the maximum transfer through line  $j-k$ , from bus  $j$  to  $k$ , corresponds to the horizontal coordinate in equation (4). As the flow in a transmission line can go in either direction, there is also a value for  $P_{jk}^{\min, st}$ , which allows us to define

feasibility intervals for each end of the line. The interval for the sending and receiving ends of the line are:

$$[P_{jk}^{\min, st}, P_{jk}^{\max, st}] = [V_j^2 G_{jk} - V_j V_k Y_{jk}, V_j^2 G_{jk} + V_j V_k Y_{jk}] \quad (5)$$

$$[P_{kj}^{\min, st}, P_{kj}^{\max, st}] = [V_k^2 G_{jk} - V_j V_k Y_{jk}, V_k^2 G_{jk} + V_j V_k Y_{jk}] \quad (6)$$

As voltages are assumed constant the interval limits can be computed directly from the base case and the parameters of the transmission line. Figure 2 shows normalized STSL intervals for the 186 sending ends of lines of the IEEE 118-bus case system. The vertical axis corresponds to the line index. The horizontal coordinate has been normalized to represent values of active power flow divided by the magnitude of the corresponding admittance of the line. The group of points in the middle corresponds to the values of active power flow in the lines for the base case condition ( $P_{jk}^0/Y_{jk}$ ). The group of points on the left and right correspond to the max and min STSL limits, respectively.

We see that at the initial operating point, all lines are feasible with respect to STSL's. Depending on the sign of the distribution factor, the flow of the line will increase to the right (positive) or to the left (negative).

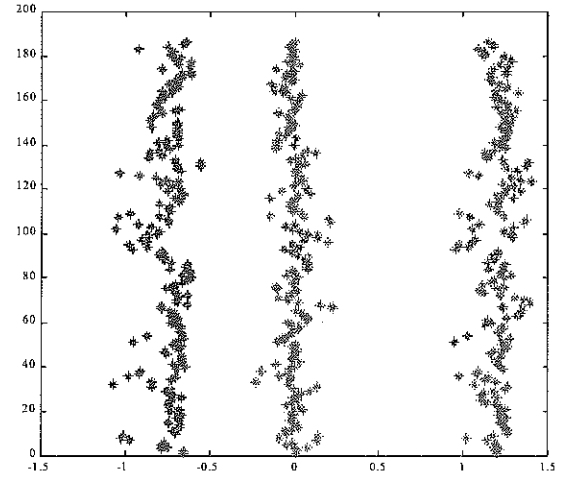


Figure 2: IEEE 118-bus case  
STSL Normalized Intervals and Initial Operating Point

The computation of STSL's is more complicated in the case where we consider that voltages vary as the transfer increases. In this case, the trajectories will be as from point A to point C in Figure 1. As the transfer increases, the trajectory will be the result of it crossing corresponding circle diagrams for different voltages. At each point over the trajectory, there is a circle diagram, whose center location and radius depend on the voltage at both ends of the line. When no discrete controls act during the transfer, the

dynamic circles are a family of slowly moving circles with varying radii and the resulting trajectories are smooth.

The movement of the complex flow can be approximated by a quadratic equation. However, it is known that near the point of collapse, the trajectory may reverse direction. Therefore, equations that allow us to reach verticality conditions must be included. We approximate the complex trajectories as a dynamic circle with unknown parameters. Consider Figure 3, which shows an assumed circle trajectory. Point 0 corresponds to the initial condition (base case) and point 1 corresponds to a deviation assuming a positive PTDF to a given parameter  $p$ . Let us assume that the parameter  $p$  is a single injection at bus  $i$ , which drives the transfer  $P_i$ . Thus  $p=P_i$ . In the case where we have multi source and sink points, participation factors would be used. In order to find the STSL, we need to find the coordinates of point C, which in turn requires finding the coordinates of point D and the size of the segment  $\overline{DC}$ .

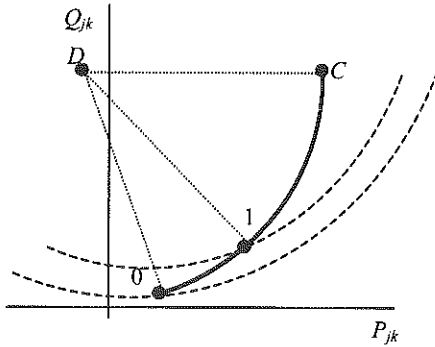


Figure 3: Computation of STSL's

In order to find the coordinates of point D, i.e.,  $P_{jk}^D$  and  $Q_{jk}^D$ , we first need to obtain the slopes of the trajectory at points 0 and 1. From Equation (1), we obtain an expression for the reactive power flow (including varying voltages) to have:

$$Q_{jk} = -V_j^2(B_{jj} + B_{jk}) + \sqrt{(V_j V_k Y_{jk})^2 - (P_{jk} - V_j^2 G_{jk})^2} \quad (7)$$

Embedding the flow to injection relation in the (active) Power Transfer Distribution Factor (PTDF) for line  $j-k$ , we make  $Q_{jk}$  depend on  $P_{jk}$ ,  $V_j$ , and  $V_k$  explicitly and on  $P_i$  implicitly, to have:

$$\begin{aligned} \frac{dQ_{jk}}{dP_i} = & -2V_j(B_{jj} + B_{jk}) \frac{\partial V_j}{\partial P_i} + \frac{1}{2} \frac{1}{\sqrt{(V_j V_k Y_{jk})^2 - (P_{jk} - V_j^2 G_{jk})^2}} \times \\ & \times \left( 2V_j(V_k Y_{jk})^2 \frac{\partial V_j}{\partial P_i} + 2V_k(V_j Y_{jk})^2 \frac{\partial V_k}{\partial P_i} - 2(P_{jk} - V_j^2 G_{jk}) \left( \frac{\partial P_{jk}}{\partial P_i} - 2V_j G_{jk} \frac{\partial V_j}{\partial P_i} \right) \right) \end{aligned} \quad (8)$$

The derivatives of the voltages with respect to the injection are obtained from the base case power flow Jacobian. We denote by  $\Psi$  the sub-matrix containing the voltage to power injection sensitivities  $\psi_{ji} = \partial V_j / \partial P_i$ . The term  $\partial P_{jk} / \partial P_i$  is the PTDF for line  $jk$  and injection at bus  $i$ , denoted by  $\rho_{jk,i}$ .

With these definitions and observing that the denominator in the second term in (8) equals the second term in (7), we write (8) as:

$$\begin{aligned} \frac{dQ_{jk}}{dP_i} = & -2V_j(B_{jj} + B_{jk})\psi_{ji} + \\ & + \frac{V_j V_k Y_{jk}^2 (V_k \psi_{ji} + V_j \psi_{ki}) - (P_{jk} - V_j^2 G_{jk})(\rho_{jk,i} - 2V_j G_{jk} \psi_{ji})}{Q_{jk} + V_j^2 (B_{jj} + B_{jk})} \end{aligned} \quad (9)$$

Note that when voltages are constant,  $\psi_{ji}$  and  $\psi_{ki}$  are zero and therefore (9) becomes infinite only when the denominator of the second term equals zero, i.e.,  $Q_{jk} = -V_j^2 (B_{jj} + B_{jk})$ , which correspond to condition (4).

Equation (9) is used to find the variation in reactive power flow due to the change in active power injection at the initial operating point. The slope of the complex flow trajectory at that point is:

$$\frac{dQ_{jk}}{dP_{jk}} = \frac{1}{\rho_{jk,i}} \frac{dQ_{jk}}{dP_i} \quad (10)$$

We evaluate equation (10) at point 0 and point 1 to form the equations for the line segments  $\overline{0D}$  and  $\overline{1D}$ :

$$Q_{jk} = Q_{jk}^0 - \frac{1}{dQ_{jk}/dP_{jk}|_0} (P_{jk} - P_{jk}^0) \quad (11)$$

$$Q_{jk} = Q_{jk}^1 - \frac{1}{dQ_{jk}/dP_{jk}|_1} (P_{jk} - P_{jk}^1) \quad (12)$$

The derivatives at point 0 are found using Equations (8)-(10) and those for point 1 are found using a small deviation, re-evaluating the Jacobian at that point and using again (8)-(10). The linear system (11)-(12) has two equations, two unknowns, and the solution correspond to the coordinates of point D,  $P_{jk}^D$  and  $Q_{jk}^D$ .

We determine the STSL noting that at point C the trajectory becomes vertical and  $dQ_{jk}/dP_{jk}|_C = +\infty$ . Thus, the horizontal coordinate of point C is given by:

$$P_{jk}^{\max,ST} = P_{jk}^D + \overline{DC} \quad (13)$$

We observe that depending on the sign of the distribution factor, the transfer will deviate from point 0 to reach either  $P_{jk}^{max,sl}$  or a corresponding limit for flow in the reverse direction,  $P_{jk}^{min,sl}$ . Thus, we need to define a new distance value  $d_{jk}$ , which takes into account the direction of the flow. This distance represents the active power flow margin to the STSL of a line for a given transfer:

$$d_{jk} = \begin{cases} \overline{DC} - P_{jk}^0 + P_{jk}^D & \text{if } \rho_{jk,i} > 0 \\ \overline{DC} + P_{jk}^0 - P_{jk}^D & \text{if } \rho_{jk,i} < 0 \end{cases} \quad (14)$$

### Estimation of the Margin to Collapse

#### Estimation Method

The calculation of the margin to collapse consists in finding the minimum variation that drives any line to its STSL. We observe that:

- The STSL's provide maximum and minimum fixed active power limits for each line end. These values are different for each transfer because the derivatives in equations (8)-(10) are transfer (and operating point) dependent.
- The necessary condition mentioned in Section II allows us to look for the first line that reaches the STSL instead of the actual point of collapse. This condition is always conservative if the STSL corresponds to the actual value. As this value depends on non-linear and discrete controls that become active/inactive during the transfer, we consider the distance obtained with equation (14) to be estimates.

The necessary injection to drive each line flow  $P_{jk}$  to the STSL, i.e., to cover the distance  $d_{jk}$ , is obtained using the corresponding PTDF for that line end:

$$\Delta P_i^{jk*} = d_{jk} / \rho_{jk,i} \quad (15)$$

The PTDF's for both ends of a line are assumed the same, but the distance  $d_{jk}$  is in general different from  $d_{kj}$ . Therefore, we choose the minimum of the values obtained with (15) for each end of a line.

$$\Delta P_i^{jk*} = \min\{d_{jk} / \rho_{jk,i}, d_{kj} / \rho_{kj,i}\} \quad (16)$$

When the transfer drives the state of the system sufficiently close to the point of collapse, we can no longer assume that the PTDF's are constant, and therefore there will be errors in the linear approximation of Equation (14). Close to the point of collapse, the strong non-linearity of the power flow equations makes the distribution factors diverge from their no-load value. The necessary condition may imply that in meshed systems there is a change of sign in at least one distribution factor near to collapse. As the total transfer

across any generalized cut in the network is almost constant, a decreasing distribution factor in a line must be compensated by an increasing PTDF in loop flow lines.

Figure 4 illustrates this behavior, which results in two effects:

- As the parameter  $p=P_i$  increases, the lines for which the distribution factor becomes larger are more likely to reach the STSL.
- The actual distance covered by the active power flow of the line from the initial operating point to a new point is equal to:

$$P_{jk}(p) = P_{jk}(p^0) + \int_{p^0}^p \rho_{jk,\bar{p}}(\bar{p}) d\bar{p} \quad (17)$$

We can write this expression as a constant PTDF term and a varying term, which accounts for the error:

$$P_{jk}(p) = P_{jk}(p^0) + \rho_{jk,\bar{p}}|_0 (p - p^0) + \int_{p^0}^p [\rho_{jk,\bar{p}}(\bar{p}) - \rho_{jk,\bar{p}}|_0] d\bar{p} \quad (18)$$

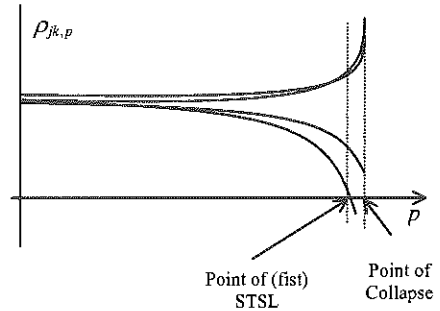


Figure 4: Behavior of PTDF's close to Collapse

We observe that if the operating point dependent PTDF,  $\rho_{jk,\bar{p}}(\bar{p})$ , increases as the transfer takes place and assuming a positive distribution factor, the third term in (18) is positive and the actual covered distance  $d_{jk} = P_{jk}(p) - P_{jk}(p^0)$  is bigger than the one used in (15). We take into account these effects by multiplying the PTDF by a factor  $K < 1$ . We believe that  $K$  between 0.65 and 0.8 is a good tuning. Applying this factor to (15) and choosing the minimum of the resulting values among all the lines (each end), the estimated margin to collapse is found as:

$$M_{Collapse,i} = \min\{\Delta P_i^{jk*} : \text{all lines } jk : \text{ends } j \text{ and } k\} \quad (19)$$

#### Numerical Results

These ideas were tested for a number of transfers simulated in the IEEE 118-bus system. We choose the parameter  $p$  to

correspond to the magnitude of bus-to-bus transfers, and we tested transfers from all the (117) buses to the slack bus. Tap changer, capacitor bank connection and related non-linear controls were kept fixed. Reactive power regulation and reactive power generation limits were taken into account. For all cases we assume that the value of the parameter at the initial operating point equal zero, i.e.,  $p^0=0$ .

We recall that the STSL's and PTDF's are transfer dependent and therefore, the values computed by (14) and (16) vary from transfer to transfer. We used a correction factor  $K=0.7$  for all the transfers. The computation process for each transfer  $i$  is as follows:

- Compute the actual value of the point of collapse in parameter space,  $p_i^*=P_i^*$ . This is only used to determine how good our estimations are.
- At the initial operating point (100% of the distance to collapse), we determine for each line the distances  $d_{jk}$ , compute the required injection  $\Delta P_i^{jk*}$  and find the margin to collapse  $M_{Collapse,i}$ .
- We repeat b) but now we find estimates at 50% of the distance to collapse, i.e.,  $P_i=0.5P_i^*$ . We repeat the process for  $P_i=0.1P_i^*$ . This is done to determine how our estimates vary as the operating point approaches the point of collapse.

The results are shown in Figure 5 in the form of histograms for 100%, 50% and 10% of the distance to collapse obtained for the base case. Each histogram includes the 117 transfers. The horizontal axis shows the fraction of the actual distance. The size of the histogram intervals are 0.1 of the distance and are centered at 0.05, 0.15, etc. This scale is reset for 50% and 10% of the distance.

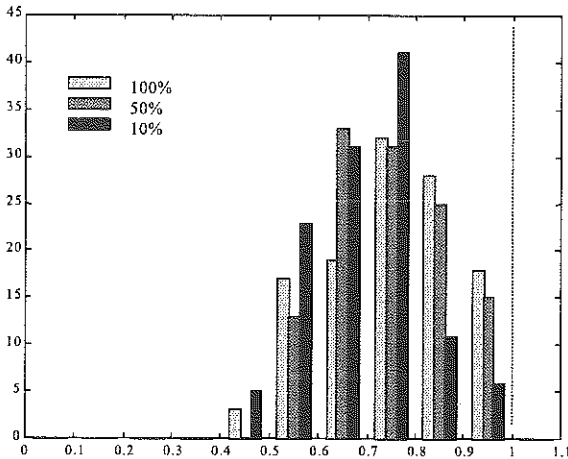


Figure 5: IEEE 118-bus case: 117 transfers  
Estimated Margin to Collapse

For instance, the first histogram indicates that when at are 100% far away from the point of collapse, we obtained

conservative estimates in the range from 0.4 to 0.5 in 3 out of 117 transfers, 17 in the range from 0.5 to 0.6, and correspondingly: 19, 32, 28 and 18, in the ranges 0.6–0.7, 0.7–0.8, 0.8–0.9 and 0.9–1.0, respectively. We see that most of the estimates are located in the range from 0.6 to 0.9.

Regarding the histograms for 50% and 10% of the distance to collapse, we see that the shape of the distribution of estimates does not change much.

#### Discussion

The results on Figure 5 let us conclude that:

- For any point in the parameter space and for every transfer the estimation of the margin to collapse is conservative. A non-conservative estimate would correspond to a non-null histogram bar in the range 1.0–1.1.
- For any point in the parameter space and for every transfer the estimation provides a positive margin, i.e., we predict that there is always room for additional transfer when there is actual room for it.
- There are cases where the predictor results in somehow conservative estimates.

The error in our estimates is due to the following factors:

- The point of the STSL condition occurs from 5% to 8% before the actual point of collapse. As we are looking for this condition instead of the actual point, we bias our estimation to the conservative side.
- The distribution factor of the limiting line, i.e., the one that reaches the STSL first does not necessarily have to be one with increasing PTDF or to increase it by an amount corrected by a factor  $K$ . The use of  $K$  around 0.7 ensures that the error is taken into account to not overshoot the estimated value.
- The assumption of circle trajectories also affects the estimation. Specifically, when lines are close to voltage regulating buses, the reactive injection tends to move the trajectory up or down in the line complex flow space even though there is a small change in active power. While these trajectories are smooth, the assumption of circle-shaped trajectories is a rough approximation. When these lines are the limiting ones, the estimates tend to be conservative.

Alternative ways to treat these effects would potentially improve the estimates. However, the results in Figure 5 presents an estimator, which does not overshoot, provides additional room for transfers and consistently provides a conservative estimate of margin to collapse. This is an example of how the smoothness of the line complex flow trajectories and quadratic nature of the power system can be exploited for large sensitivity analysis.

#### Application to Linear Security Functions



When the operating point is away from collapse, the estimator gives always an additional margin for variation of the parameter  $p$ . We can use this property to automatically incorporate supervision of collapse in linear security functions. Once we have calculated MW-corrected thermal limits [10] and STSL's as described in previous sections, we can compare thermal limits against STSL's for each line end and choose the minimum. If the STSL is lower than the thermal limit, we replace this value and flag the transmission line. If during the computation expression (19) identifies the line as the limiting element, there is a potential collapse condition for that change in  $p$ . If the STSL is larger than the MW-corrected thermal limit, we keep the thermal limit as the active one, as this limit will be detected first.

Additionally, we could incorporate a logic that triggers the execution of an iterative estimation step or that activates a full non-linear computation if the estimated margin is too low and the limiting element is a collapse-flagged line. Based on the estimation values, the full non-linear simulation would only be required when (conservative) collapse conditions appear before thermal limits, which we expect will occur in few cases. Thus, our estimation method can be used as a filter in linear security functions. It is indispensable though to analyze potential collapse problems if after (19) we encounter a flagged transmission line. The fact that we can replace thermal limits by STSL's if the operating conditions determine so, allows the direct inclusion of STSL's in linear security functions such as linear contingency analysis and linear static ATC [9].

The method could also be used in security constrained OPF as a check for collapse conditions. In this algorithm thermal limits would be replaced by STSL when the former are likely to be reached before thermal limits, and the solution observing "thermal" limits would automatically filter cases of collapse. This is the only requirement because when all lines in the system are feasible with respect to STSL's, collapse due to variations of active power will not occur.

The implementation of this approach as a filter for collapse conditions in linear static ATC, linear contingency analysis and OPF are left for further research.

## Conclusions

A method for the estimation of collapse using network complex flows has been described. The method looks for the condition where the first line in the system reaches the STSL. The STSL will occur close to the point of collapse and before it.

The STSL's are approximated for the sending and receiving ends of individual lines assuming that the complex flow trajectories are circle-shaped. A theoretical justification for this assumption has not been developed. The coordinates of

these circles are found using sensitivity information from the base case power flow. The method requires the reevaluation of the power flow Jacobian for a deviation point. The STSL for each end of each line is approximated as a function of the circle parameters and the initial flow of the line. The margin to STSL, which is always very close to the margin to collapse, is found by choosing the minimum margin among all the line and line ends using linear techniques.

The margins obtained with this method are conservative with respect to the actual margin to collapse. Most of the estimates are in the range of 50 to 80% of the actual distance to collapse. The assumptions of constant distribution factor, that the condition of STSL appears at the point of collapse and the trajectories are circle-shaped are the factors that affect the accuracy of the estimator.

The fact that this margin was derived using properties of individual transmission lines makes the method appealing for use in static security functions such as static linear contingency analysis, linear ATC and security constrained OPF.

## Acknowledgements

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## Discussions on Session IV: TRANSACTION EVALUATION & CONGESTION MANAGEMENT

### Part 2

**Chairman (J. K. Park):** The speakers talked about the ATC. Is there any discussion to the speakers?

**C. Canizares (University of Waterloo):** I just have a question for Pete. I'm still a little bit fuzzy about the reason for doing what you are proposing. I guess you do it because you like it, but I would like to understand the motivation for not actually going, just do the competition straightforward. I guess PTDFs are very popular but I guess you do have the optional to do the whole thing. Just want to understand the motivation.

**P. Sauer:** In the case of linear ATC, those are so fast that they are orders of magnitude more efficient than anything like load flow. These are simple multiply / divide, and you have the answer. It's a very popular method anywhere, where stability is not a problem. So I make no claim at all about stability of course, it would be purely static. But the linear ATC answers when there may not be an answer. So you could be using a linear ATC method, and it maybe predicting an answer when you have exceeded the collapse limit. If you don't do anything, you won't know that. Now you're right, I could follow up with the full AC power flow or continuation power flow. That's a huge computational burden relative to what linear ATC is. Linear ATC is a simple multiply / divide for each line, so we're looking for something in between doing nothing and doing a full voltage collapse computation, and the result was that you have this local geometric check, quadratic equation at each end of the line, simple scalar quadratic computation. So the motivation is to keep it as close to the speed of linear as possible but still have some prediction of the failure of the linear system.

**C.-C. Liu (University of Washington):** I've been trying to see if you would cover the dynamics for ATC, but unfortunately you get the appetite wet, but didn't really get into that. So we have a little bit time, maybe I can ask the authors to project a little bit on how dynamics can be included, particularly Professor Chiang mentioned that. He said he's working on that. Can you shed some light?

**H.-D. Chiang:** In the package I presented today, we just handle steady state stability limit, voltage violation, and thermo limits. For transient stability, the BCU limiter is the function. Given a direction in a parameter space, this BCU limiter will tell you how far you can go. Within this value, all the transient stability constraints are satisfied. What we would do is like a look ahead

function, we use a look ahead to rank each contingency. We will add another column that is transient stability limit to choose the rank. Then based on the estimated Lambda, the physical meaning of Lambda is how far you can go, you can do a ranking. Mix these four classes together, and pick top ten, and do a detailed analysis. Of course what we have missed here is a small signal stability limit, and that can be handled if you have a continuation power flow which we call a CD FLOW, Continuation Dynamic Power Flow system, to handle this small signal stability limit.

**S. Meliopoulos:** Well, first of all, the dynamics in the ATC calculation have to take into consideration the type of system. I guess the problems are basically if you compute the dynamic stability limit, then they are larger than the static, so you don't need to do anything. Similarly, a lot of places in the eastern United States, that will be the case. Of course if you go to the west, they change. Now in another issue with that is many times that is an issue in between, full dynamic consideration versus what is this happened during the contingency. We're working presently on the following issue. When the contingency occurs, immediately after the clearing of the contingency, you have the system in a different state because of induction motors of the loads that would be moved during the fault condition. When the fault is cleared, you're dealing with a system that behaved differently than prior to the contingency. So we're going to find out what would be the limits by looking at the post clearing state of the system and how this affects the available transfer capability of the system. So this is an in-between ground between full dynamic consideration versus static.

**P. Sauer:** There is a graph, given a transmission line in meters or kilometers, there is a vertical axis in SIL, surge impedance load. The bottom line is that for a short line the line is thermally limited; for medium length line its voltage drops limited; and for a long line it is stability limited. You can't come up with one number that describes the limit of the line in terms of thermal voltage drop and steady stability. Transient stability, as we all know, is a tough one. There are brute force methods - just simply running transient stability studies. There are direct methods that are faster. There is a possibility of using sensitivity of stability margin to transaction. We've played around with that a little bit using a linear sensitivity to try to predict the stability limit of a transaction by looking at the sensitivity of the transient stability margin to the transaction itself. You can do a

linear sensitivity. It works ok. That is a possibility as a first step to avoid full transient stability, but you bring up a tough question, so people are still working on that.

**C.-C. Liu:** That is very insightful. How do you calculate the TRM? You talked about ATC and so forth but you're really talking about TTC.

**P. Sauer:** Yes. The TTC, as all these components, I guess we can get into that. There is a CBM capacity benefit margin, and TRM. I always thought of TRM, as somebody else had it on the slides, I think it was this morning. The safety margin that you can arbitrarily apply, and I know that in some utilities, they just arbitrarily call it 50 megawatts. So the TRM equals 50 megawatts. That's one way. Another way is to say that it is 8% or 10% of the solution. You simply push the system all the way to a stability margin, perhaps all the way to a thermal limit, and you back it off 10%. It's a purely arbitrary number. That's the only mechanism I've ever heard of it that anybody that this is my TRM, my TRM is 8% of the TTC, or they will say TRM is 50 megawatts. So that is as much as I know about TRM.

**Chairman:** Thank you Professors Liu and Sauer. It is time. We should stop here. Thank you.

**Session V:**  
**OPERATIONS PLANNING**

Wednesday, August 29, 09:00–12:00

Chair: Shinichi Iwamoto

## Dispatching for Preventive and Corrective Control of Voltage Collapse in a Deregulated Power System

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### 1.0 Introduction

Deregulation has brought opportunities for increasing efficiency of production and delivery and reduced costs to customers. Deregulation has also brought great challenges to provide the reliability and security customers have come to expect and demand from the electrical delivery system. One of the challenges in the deregulated power system is voltage instability. Voltage instability has become the principal constraint on power system operation for many utilities. Voltage instability is a unique problem because it can produce an uncontrollable, cascading instability that results in blackout for a large region or an entire country.

In this work we define a system of advanced analytical methods and tools for secure and efficient operation of the power system in the deregulated environment. The work consists of two modules; (a) contingency selection module and (b) a security constrained optimization module.

The contingency selection module to be used for voltage instability is the Voltage Stability Security Assessment and Diagnosis (VSSAD). VSSAD shows that each voltage control area and its reactive reserve basin describe a subsystem or agent that has a unique voltage instability problem. VSSAD identifies each such agent. VSSAD is to assess proximity to voltage instability for each agent and rank voltage instability agents for each contingency simulated based on the reactive reserves that are unexhausted in that agent. Voltage instability or voltage collapse occurs when the appropriate agent's reactive reserves are exhausted. Contingency selection and ranking for each agent is also performed. Diagnosis of where, why, when, and what can be done to cure voltage instability for each equipment outage and transaction change combination that has no load flow solution is also performed.

A security constrained optimization module developed solves a minimum control solvability problem. A minimum control solvability problem obtains the reactive reserves in specific agents through action of voltage control devices that VSSAD determines are needed to obtain solution of the load flow. VSSAD makes a physically impossible recommendation of adding reactive generation capability to specific generators to allow a load flow solution to be obtained. The minimum

control solvability problem can also obtain solution of the load flow without curtailing transactions that shed load and generation as recommended by VSSAD. A minimum control solvability problem will be implemented as a corrective control, that will achieve the above objectives by using minimum control changes. The control includes; (1) voltage setpoint on generator bus voltage terminals; (2) under load tap changer tap positions and switchable shunt capacitors; and (3) active generation at generator buses. The minimum control solvability problem uses the VSSAD recommendation to obtain a feasible stable starting point for the security constrained optimization program and then completely eliminates the impossible or onerous recommendation made by VSSAD.

This paper reviews the capabilities of Voltage Stability Security Assessment and Diagnosis and how it can be used to implement a contingency selection module for the Open Access System Dispatch (OASYS). The OASYS will also use the corrective control computed by the Security Constrained Dispatch. The corrective control would be computed off line and stored for each contingency that produces voltage instability. The control is triggered and implemented to correct the voltage instability in the agent experiencing voltage instability only after the equipment outage or operating changes predicted to produce voltage instability have occurred. The advantages and the requirements to implement the corrective control are also discussed.

### 2.0 Voltage Stability Overview

#### 2.1 Review of Voltage Stability Methods

Voltage stability is the ability of a power system to preserve the voltage of an operation equilibrium under normal condition and to maintain an acceptable voltage at all buses after being subjected to a disturbance. A system will start to lose stability and enters the state of instability when a disturbance, changes in system operating condition, or increase in load demand causes a progressive and spreading drop in voltage. The incapability of the power system to meet the reactive power demand is the main cause of voltage instability. The drop in voltage results in (a) reducing shunt capacitive reactive supply and (b) increasing magnetic field due to increased current flow that together increase the network reactive losses. The

increased network losses result in (1) reducing reactive power flow to the region that needs the most reactive supply and (2) exhaustion of the reactive reserves on generators, synchronous condensers, or SVC's causing loss of voltage control that result in further voltage drop and further increase in network reactive losses.

Voltage collapse has been studied in a load flow (algebraic) and in a differential algebraic model. It has been shown that bifurcation sequences occur in a differential algebraic model that can include saddle node, Hopf, singularity induced, or algebraic bifurcation [19]. Instability in the dynamics can occur before the bifurcation affects the algebraic model. It has been shown that saddle node bifurcation in a differential algebraic model at equilibrium is a bifurcation in the load flow model that includes the algebraic model and differential model at equilibrium [2]. In other cases, the bifurcation solely in the algebraic model has no effects on generator dynamics (algebraic bifurcation) or alternately in the algebraic model that produces very rapid changes in generator dynamics (singularity induced bifurcation)[19]. The bifurcation in the algebraic equations is almost always associated with the ultimate blackout even when saddle node or Hopf bifurcation initiates the instability that results in blackout [4, 19].

This paper will only discuss the voltage stability problems in an algebraic model,  $f(x, p)$  where  $x$  is the  $n$  dimension state of the model and is of the same dimension as  $f(x, p)$  and  $p$  is an  $m$  vector of parameters that can change and produce bifurcation or instability if  $p$  changes continuously. The implicit function theorem can indicate when solutions exist and the solutions are unique.

#### Theorem (Implicit function theorem) [3]

Let  $f = (f_1, \dots, f_n)$  be a vector valued function defined on an open set  $S$  in  $R^{n+k}$  with values in  $R^n$ . Suppose  $f \in C^1$  on  $S$ . Let  $(x_0, p_0)$  be a point in  $S$  for which  $f(x_0, p_0) = 0$  and for which the  $n \times n$  determinant  $\det[f_x(x_0, p_0)] \neq 0$ . Then there exists a  $k$ -dimensional open set  $P_0$  containing  $p_0$  and one, and only one, vector-valued function  $g$ , defined on  $P_0$  and having values in  $R^n$ , such that

- a)  $g \in C^1$  on  $P_0$ ,
- b)  $g(p_0) = x_0$ ,
- c)  $f(g(p); p) = 0$  for every  $p$  in  $P_0$ .

When the Jacobian is nonsingular the implicit function theorem indicates there exist solutions that are unique for all  $p_0 \in P_0$ .

When a solution exists, the system may be stable or unstable depending on whether there are any non positive eigenvalues of

the Jacobian  $f_x(x_0, p_0)$ . However, when no solution exists the system is considered unstable and this singularity of load flow Jacobian can be used to detect voltage instability. When the  $\det[f_x(x_0, p_0)]$  is zero or the Jacobian  $f_x(x_0, p_0)$  is singular, the implicit function theorem does not provide any information but it may imply no solution  $x_0 = x(p_0)$  exists at these values of  $p_0$  or there are multiple solutions  $x_{0i}(p_0)$ .

Both can be true as will be noted later. A number of indices have been developed to test for load flow bifurcation when  $p$  is changed in some direction  $n$

$$p = p_0 + kn \quad (2.1)$$

via change in  $k$  until  $\det[f_x(x^*, p^*)] = 0$ . The indices come from tracking the minimum eigenvalue  $\lambda_i^*(k)$  using

$$f_x(x(k), p(k))u_i(k) = \lambda_i(k)u_i(k) \quad (2.2)$$

where  $\lambda_i^*(k) = \min_i[\lambda_i(k)]$  or the minimum singular value  $\sigma_i^*(k)$  obtained using

$$f_x(x(k), p(k))^T f_x(x(k), p(k)) = W_\sigma(k) \Sigma(k) V_\sigma^T(k) \quad (2.3)$$

where  $\Sigma(k) = \text{diag}[\sigma_1(k), \sigma_2(k), \dots, \sigma_n(k)]$

and  $\sigma_i^*(k) = \min_i[\sigma_i(k)]$

The singular values  $\sigma_i(k)$  are the eigenvalues of

$$f_x(x(k), p(k)) f_x^T(x(k), p(k)) \quad (2.4)$$

And satisfy

$$f_x(x(k), p(k))v_i(k) = \sigma_i(k)w_i(k) \quad (2.5)$$

$$w_i^T f_x(x(k), p(k)) = \sigma_i(k)v_i^T(k) \quad (2.6)$$

where  $v_i(k)$  and  $w_i(k)$  are the right and the left singular vectors of  $\sigma_i(k)$  and are columns of matrices  $V_\sigma(k)$  and  $W_\sigma(k)$  above.

The minimum singular value and minimum eigenvalue are just two of many sensitivity based indices or measures of proximity to voltage instability.

The Q-V and P-V curve are particular scalar ( $m = 1$ ) proximity measures where

(1) for a Q-V curve the direction  $\underline{n}$  vector is a unit vector where the voltage at a bus  $i$  is the only nonzero element,  $k$  is the real valued negative number that starts at zero and decreases, and  $-Q_i(V_i)$  is the reactive load that is added at bus  $i$  for each value of  $V_i$ . The curve  $Q_i(V_i)$  is the reactive injection at bus  $i$  obtained by changing the bus type from a load bus to a generator bus, reducing the voltage  $V_i$  until  $Q_i(V_i)$  reaches a minimum at  $V_{i\min}$  with maximum added load

$-Q_i(V_{i\min}) = Q_{i\min} \geq 0$ . The value of

$(V_{i\min}, Q_{i\min})$  defines the minimum of the Q-V curve

where  $\frac{\partial Q_i}{\partial V_i} = 0$ , that corresponds to the bifurcation point

$(x^*, p^*)$ .

(2) The P-V curve can add active power load at a bus  $i$  or at several load buses simultaneously

$$p = p_0 + kn_{\text{load}} \quad (2.7)$$

and pick up that power at several generators

$$g = g_0 + kn_{\text{gen}} \quad (2.8)$$

Where  $n$  is made up of  $n_{\text{gen}}$  and  $n_{\text{load}}$  and both are participation vectors where  $\sum n_i = 1$ .

A P-V curve can also result in transfer power from one set of generators  $g^*$  to another set of generators  $\hat{g}$

$$g^* = g_0^* + kn^* \quad (2.9)$$

$$\hat{g} = \hat{g}_0 - k\hat{n} \quad (2.10)$$

Note  $n_{\text{gen}}, n_{\text{load}}, n^*$ , and  $\hat{n}$  are unit vectors where one or more elements are nonzero and  $\sum n_i = 1$ . The P-V curve plots voltage at some bus  $i$  for change in  $k = P_{\text{system}}$  where it represents system power load change or  $k = P_{\text{transfer}}$  represents the total power transfer change.

Optimization based methods have been used to calculate Q-V and P-V curves in [5]. These scalar optimization based methods optimize performance index  $Q_i$  to produce a Q-V curve with load flow equality constraints

$$f(x, p, u) = 0 \quad (2.11)$$

And inequality constraints on voltage controls  $u$ . These controls can include under load tap changer tap position, switchable shunt capacitor susceptance, and possibly generator excitation control set points. The P-V curve computed by load flow for varying  $k = P_{\text{system}}$  or  $P_{\text{transfer}}$  has all or most of

these controls fixed. The P-V curve would optimize  $P$  for a particular transfer or wheeling transaction with the same load flow model, same controls  $u$  and inequality constraints on controls  $u$ . The particular transfer or wheeling transaction is

defined via specification of  $n_{\text{gen}}, n_{\text{load}}, n^*$ , and  $\hat{n}$ . In [6], a scalar optimization based method was proposed to maximize the reactive power margin when  $n$  can be a unit vector with several nonzero elements. This generalized Q-V curve allows added reactive load at several buses in the participation factor normal direction rather than just one as in a typical load flow based Q-V curve. The approach used in [6] eliminates the active power and phase angle relationship, using active power generation as control, and imposes reactive power limits on the generators. Dobson [7] is first to develop a vector optimization based method that optimizes the normal direction vector  $n$  and the loading factor  $k$ , which are assumed to be positive real numbers. This paper computes load power at which saddle node bifurcation occurs, that represent the worst case load power parameter variation. The proximity measure  $|p^* - p_0|$

to saddle node bifurcation, where  $p_0$  and  $p^*$  represent the current load power and the critical load power respectively, was first noted in this paper [7].

All of these methods [5, 6, 7] assess bifurcation in a single mode due to continuous scalar or vector parameter variation. The methods are thus not applicable to assessing proximity to voltage collapse for equipment outage or transactions that are modeled by discontinuous parameter change where it will be shown that several modes approach zero simultaneously and voltage collapse occurs when one specific mode is zero. There appears to be no method for explaining which mode is critical, why it is critical, and how is it related to the other modes that are also bifurcating. The explanation is given in VSSAD [8, 10, 11]. These methods also do not take into account the discontinuity in eigenvalues that occur for continuous parameter and discontinuous parameter changes. In many cases the eigenvalue changes due to discontinuities is virtually all the change that occurs in an eigenvalue that approaches bifurcation [10].



*The Voltage Stability Security Assessment and Diagnoses [1, 8, 10, 11]*

1. determines the number of discontinuities in any eigenvalue that have already occurred due to generator PV to load PQ bus type changes that are associated with an eigenvalue. The eigenvalue is associated with a coherent bus group (voltage control area). The set of generators that experience PV-PQ bus type changes (reactive reserve basin) for computing a Q-V curve at any bus in that coherent bus group are proven to capture the number of discontinuities in that eigenvalue before bifurcation. The reactive reserves on generators in each voltage control area of a reactive reserve basin measure proximity to each of the remaining discontinuities in the eigenvalue required for bifurcation in the agent composed of the test voltage control area and its reactive reserve basin. A second proximity measure for an agent is the percentage of voltage control areas in its reactive reserve basin that are unexhausted [10];
2. can handle discontinuous (equipment outage or large transfer or wheeling transaction changes) or continuous change (load increase, transfer increases, and wheeling increases) where the above methods are restricted to continuous changes even if some prior discontinuous change occurred. The VSSAD proximity measures are computed at the solution after the equipment outage or discontinuous operating change and require no continuous change to compute distance to the bifurcation point;
3. the existence of a bifurcating mode for each agent is theoretically proven and estimated. This theory establishes VSSAD as a modal method based on the VSSAD proximity measures relationship to these eigenvalue estimates [8, 10, 11]. The eigenvalue estimate proves that the agent becomes unstable when the agent's reactive reserve basin reserves are exhausted. This agent reactive reserves basins are nested and as each successively larger reactive reserve basin is exhausted, the instability that should result at the bifurcation in that agent is observed on the agents with even larger reactive reserve basins. The cascading instability of agents initiates voltage collapse when a critical agent's reactive reserves are exhausted.
4. can simultaneously assess proximity to voltage instability for all agents with bifurcation modes in a system by assessing either the percentage of voltage control areas in each agent's reactive reserve basin with zero reserves or the reactive reserves remaining on each agent's reactive reserve basin voltage control areas that have not yet exhausted reserves. This ability allows one to detect the instability that occurs when each agent's reactive reserves exhaust, and the cascading instability that occurs when the critical agent exhausts its reactive reserves;
5. can provide operating constraints or security constraints on each agent's reactive reserve basin reserves that prevent voltage instability in each agent in a manner identical to how thermal constraints prevent thermal overload on each branch and voltage constraints prevent bus voltage limit violation at each bus. This capability has been demonstrated on the 162 bus system using an optimal active dispatch and an optimal reactive dispatch where reactive reserve basin constraints were added. When reactive reserve basin constraint were ignored, the optimal active dispatch drove the system into voltage collapse in an effort to minimize fuel costs. When reactive reserve basins constraints were imposed, the voltage collapse never occurred. The same phenomena was observed for the optimal reactive dispatch on this 162 bus system;
6. the reactive reserve basin operating constraints allow optimization that assures that correcting voltage instability problems in one agent will not produce voltage stability problems in the other agents in the rest of the system. This is demonstrated later in this paper;
7. the reactive reserve basin constraints after an equipment outage and operating change combination allows optimization of transmission capacity that specifically corrects that particular equipment outage and transaction change induced voltage collapse. This is demonstrated in this paper;
8. can be computed for any of the Q-V and P-V curve stress tests discussed earlier.

### 3.0 Types of Voltage Instability

Two kinds of voltage instability have been associated with a load flow model [8]:

#### 3.11 Loss of Control Voltage Instability

Loss of control voltage instability is caused by exhaustion of reactive supply with resultant loss of voltage control on a particular set of generators, SVC's, or synchronous condensers in a critical agent's reactive reserve basin. The loss of control voltage instability not only cuts off the reactive supply to a region requiring reactive power supply, but also increases the network reactive losses that choke the network and blocks reactive power supply from reaching that region needing reactive power. Loss of control voltage instability occurs in the transmission and subtransmission system due to equipment outages and operating changes combination, such as

- line, transformer, and generator outages

- generator outage with a particular real power generation pickup pattern
- increase in load and generation
- change in wheeling, transfer, and interchange transactions

### 3.1.2 Clogging Voltage Instability

Clogging voltage instability occurs due to reactive power series  $I^2X$  losses, tap changers reaching tap limits, switchable capacitor reaching susceptance limits, and shunt capacitive withdrawal due to decreasing voltage. These network reactive losses can completely block the reactive power flow from reaching the region needing the reactive power supply without even exhausting any reactive reserve and loss of any voltage control on generators, SVC's, and synchronous condensers. This effect can occur in distribution, subtransmission, and even in transmission system. Clogging voltage instability occurs due to increased wheeling, transfer, and interchange transaction changes or loading and generation pattern change.

### 3.2 Knowledge Development

There are off-line and on-line aspects of the Voltage Stability Security Assessment. The off-line task is knowledge development via learning through applying stress tests. The knowledge gained from the off-task is then used in the on-line task to assess severity and diagnose the voltage instability problem. The knowledge development aspects are to identify the following [8]:

- Parameters that make a particular region and subregion vulnerable to voltage collapse.
- The structural cause of voltage collapse.
- A proximity measure for identifying how close the region and subregion is to voltage collapse.

The on-line aspects of Voltage Stability Security Assessment are; (a) to identify and rank the most insecure region and subregion, (b) to find the equipment outages that cause voltage collapse in any region, (c) and finally to rank the equipment outages that bring the region and subregion closer to voltage collapse [8].

The first step in the knowledge development aspect of VSSAD is the stress test. In this stress test we acquire knowledge about each agent or subsystem that can experience voltage instability and in each agent the structural cause of voltage instability in that agent. The stress test will explain why any equipment outage or operating change will cause voltage instability to occur at any bus or group of buses. Since loss of control

voltage and clogging voltage instabilities are both due to shortage of the reactive power supply to a bus or group of buses in the region or subregion, the stress test must determine why and when voltage instability occurs due to shortage of reactive power supply. Thus, a Q-V curve is used as the stress test for the knowledge development aspect of voltage stability security assessment and diagnosis since it determines the maximum amount of reactive load that can be added to the bus before voltage instability occurs and the load flow no longer has a solution. A P-V curve, although quite useful in assessing maximum transfer, wheeling, and interchange before voltage instability occurs does not relate to shortage of reactive power supply. Another reason why a P-V curve is not as effective as a Q-V curve is that P-V curve does not effectively pinpoint each agent's subregion where reactive power supply shortage occur in the system for generator outages or line outages. This region is the union of all agents' subregions that have their reactive reserve basins nested in the critical reactive reserve basin. This information is easily identified using Q-V curves. A final reason for not using P-V curve is that the minimum singular value of the reactive power Jacobian approximates the changes in the minimum singular value of the full load flow Jacobian [8].

The second step of the knowledge development aspects of voltage stability security assessment is to acquire knowledge about each agent or subsystem composed of the test voltage control area and their reactive reserve basin. Computing Q-V curves at every bus in a region and determining the set of generators, that exhausted their reactive reserves (the reactive reserve basin) in the process of reaching the Q-V curve minima at each bus, is needed to identify the agents. The agent is a coherent bus group where all the Q-V curve minima are identical and the reactive reserve basin for every bus in that coherent group is identical. Voltage control areas are the coherent bus groups that have the same Q-V curve minima and the same reactive reserve basin. The algorithm [13, 14] for selecting the size of each nonoverlapping coherent bus group so all the buses in each group have the same voltage instability problem requires the connection between buses in that group have very low impedance. The most important attribute of voltage control areas and their reactive reserve basins is that they don't change when severe contingencies and operating changes occur that cause voltage instability. Another important fact is that more than one voltage control area can have the same reactive reserve basin.

Exhausting all of the reactive reserve in a reactive reserve basin in an agent and thus losing voltage control at all these generators will cause voltage instability or near instability in every agent (voltage control area and associated reactive reserve basin) with that reactive reserve basin. The reactive reserve basin provides the reactive supply needed to prevent every agent with that reactive reserve basin from experiencing voltage instability. The subset of agents with the same reactive reserve basin is called a voltage collapse region. The

exhaustion of all the supply in the reactive reserve basin causes voltage instability in the associated voltage collapse region. Reactive reserve basins and their agents that contain them can be classified as global, local, or critical. These reactive reserve basins appear as a tooth with several roots as discussed in [10, 11]. Each tooth represents the load center where the largest global reactive reserve basins are at the crown of the tooth and the small load reactive reserve basins are at the tip of roots that is associated with agents near or in the distribution system. Global agent reactive reserve basins are associated with test voltage control areas of the EHV transmission grid encircling different load centers. This global reactive reserve basins generally overlap but usually belong to electrically and geographically distinct regions of the transmission system. A global reactive reserve basin can contain one or more nested sets of smaller reactive reserve basins. These are called local agent reactive reserve basins and contain fewer generators than global agent reactive reserve basins and their test voltage control areas are either electrically or geographically more remote from generators than the voltage control areas associated with global agent reactive reserve basins. One or more of these nested sets of progressively smaller local reactive reserve basins can not only cause voltage collapse in the associated test voltage control area of its agent, but also can cause voltage collapse in test voltage control areas of agents associated with all smaller local reactive reserve basins that are nested in it as well as some larger reactive reserve basins in which its local reactive reserve basin is itself nested [18]. Such a local reactive reserve basin is called a critical reactive reserve basin and is most often electrically remote and initiates the voltage collapse when its reactive reserve basin reserves are totally exhausted.

The final step of the knowledge development aspects of VSSAD is to select a proximity measure for voltage collapse in voltage collapse region and subregion. There are two measures of proximity to voltage instability or collapse. The most obvious measure is the percentage of reactive reserve available after contingency has occurred in the reactive reserve basin compared to that of the base case, which often is the peak load case with no contingency. The other measure of proximity to voltage instability or collapse requires the list of generators in the reactive reserve basin that belongs to voltage collapse region be grouped by the voltage control area they belong to. This measure is the percentage of a reactive reserve basin voltage control areas that are unexhausted after a contingency.

### 3.3 Intelligence Development

The knowledge development or the learning activity of finding voltage collapse regions and their associated reactive reserve basins must be completed before applying the on-line contingency selection and ranking aspects of VSSAD. The contingency selection and ranking procedure is an intelligence development task because it ranks the worst contingencies that have a load flow solution for each voltage collapse region as

well the most insecure voltage collapse region for each contingency. The outline procedure of the On-Line process of VSSAD is as follows [8]:

1. Rank the worst single line and generator outage contingencies for each voltage collapse region in terms of the smallest percentage of unexhausted reactive reserve of that agent's reactive reserve basin after the contingency;
2. Find and list all of the single line outage and generator outage contingencies that will exhaust more than P% of the reactive reserve in any agent's reactive reserve basin;
3. Simulate a list of double line outages, double generator outages, and a combination of line and generator outages contingencies from the list of line and generator outages found in step (2);
4. Rank the worst contingencies produced in step (3) for each agent's reactive reserve basin in terms of the smallest percentage of reactive reserve remaining in the reactive reserve basin. This procedure has been validated on 10,000 bus models with excellent success.
5. Rank the agents for each equipment outage to determine how many local agents reactive reserve basin reserves are totally exhausted.

The contingencies with zero reserves for any agent's reactive reserve basin may be experiencing voltage instability in that agent's voltage collapse region and its reactive reserve basin. If it is not possible to say the agent is experiencing voltage instability because it may still be obtaining sufficient reactive supply to survive from outside and thus not be experiencing blackout. With zero reserves in several nested reactive reserve basins, one is virtually certain voltage collapse has occurred. This information can be obtained by observing the ranking of agent reactive reserve basins for any contingency (step 5). If the percentage of voltage control areas within several nested reactive reserve basins with zero reserves is small but not zero for a particular contingency, the system is very near voltage collapse since as exhaustion of the reserves on voltage control areas in a reactive reserve basin occurs, the network reactive losses rise exponentially for each subsequent exhaustion of reserves in yet another unexhausted reactive reserve basin voltage control area. If it is also known that when the reactive reserves in all voltage control areas of a critical agent's reactive reserve basin in a nested set occurs, many if not all larger reactive reserve basins in that nested set also exhaust reserves. This explains why several agent reactive reserve basins in a nested set will approach exhaustion of reactive reserves simultaneously. The eigenvalues associated with each agent having zero reserves also go to zero causing the phenomena that makes establishing where, how, and why voltage collapse occurs using model methods so difficult. There is no difficulty using VSSAD even on 10,000 bus or larger models.

### 3.4 Diagnosis of Voltage Instability

The use of the physical structural knowledge developed of voltage collapse regions and agents (voltage control areas and their reactive reserve basins) provides a basis for performing diagnostics of the location, cause, and remedial action for each equipment outage and operating change combination that cause voltage instability. The physical structural knowledge developed and the diagnostic capability far exceeds that can be accomplished by; (a) doing trial and error effort to obtain a load flow solution by adjusting operating conditions, load and generation reduction, or adding new reactive supply sources (b) finding the last best iteration for a specific equipment outage and operating change combination; or (3) by ignoring the reactive limits on the generators. The diagnosis would suggest whether lack of load flow solution is an algorithmic convergence problem or whether it is voltage instability. Diagnosis can also indicate if voltage stability margin is increased following the control action changes. The diagnostic capability also indicate where, why, and what to do about loss of control voltage instability or clogging voltage instability. Two diagnosis methods has been identified in voltage stability security assessment and diagnosis (VSSAD). One diagnostic method is for loss of voltage control voltage instability, and the other is for clogging voltage instability. The diagnosis for loss of voltage control voltage instability is performed first and if the method fails to obtain the load flow solution, then the diagnosis for clogging voltage instability is applied. There are two cases where the diagnosis may not work; (a) outage of all generators in a reactive reserve basin since additional reactive generation may be needed in that reactive reserve basin to obtain a solution; (b) outage of branches that cause isolation of a bus or subsystem. This often requires action that are above and beyond system dispatch of generation and voltage control devices, and require system commitment of additional lines and generators. The diagnosis is thus solely for equipment outages where dispatch of generation or voltage control devices can provide a load flow solution.

#### 3.4.1 Loss of voltage control voltage instability

Loss of control voltage instability occurs because the reactive reserves in a one or more agent's reactive reserve basins are all exhausted due to the contingency. Exhaustion of an agent's reactive reserves and thus loss of voltage control on all generators in its reactive reserve basin produces dramatic increase in network reactive losses as well as terminating reactive supply from these generators. Ignoring reactive limits in all the generators in the network

$$Q_{Gi_{min}} \leq Q_{Gi} \leq Q_{Gi_{max}} \quad (3.12)$$

and solving the load flow would indicate which generators and which reactive reserve basins exceed their reactive limit causing the reactive reserve basin to be negative.

$$RR(P) = \sum_{i \in RRB(P)} (Q_{Gi_{max}} - Q_{Gi}) \quad (3.13)$$

where:  $RR(P)$  is the reactive reserve in reactive reserve basin  $P$ , and  $i \in RRB(P)$  is the set of all the generators in reactive reserve basin  $P$ .

The reactive reserve basin with the most negative reserve generally causes the lack of a load flow solution. Adding reactive reserves to that reactive reserve basin by:

- Switching in shunt capacitors;
- Changing voltage setpoints on generator's exciters;
- Adding additional generators (Peakers)

can help the load flow to have a solution. On the other hand if reactive limits are ignored and no load flow solution exists then a lack of load flow solution is due to clogging voltage instability.

#### 3.4.2 Clogging Voltage Instability

If the solution to the load flow does not exist even though that the reactive limit on all of the generators are ignored, then the lack of solution is because of the reactive losses choke off the flow of reactive supply to a region or subregion needing reactive supply.

Methods for obtaining a solution for clogging voltage instability involve (a) trying to reduce the loads and generation (transfer or wheeling transaction reductions or modifications) in agents where collapse occurs until the load flow solves, or (b) adding fictitious reactive power supply (generators) at buses in the agent's test voltage control area until the load flow has a solution. These procedures can take an average of 15 hours of engineering effort per contingency to find a solution. A diagnostic procedure for clogging voltage instability is as follow:

1. for the double contingency that has no load flow solution find the reactive reserve basin where each single contingency exhausts 50% or more of the reserves.
2. the reduction of real and reactive load at all buses in voltage collapse regions and reduction of generation on the generators in their reactive reserve basins will generally obtain a load flow solution.

The above procedure works because adding reactive load at buses in the voltage collapse region causes increased reactive

losses that together exhausts reactive reserves in the reactive reserve basin, and the contingencies in the voltage collapse region cause increased reactive losses that also exhausts reserves in these same reactive reserve basins. Reducing load should reduce the reactive losses produced by the double contingency that causes clogging voltage instability. The above procedure is very dramatically modified when applied to large systems.

In a deregulated environment voltage collapse problems will become much more common. Deregulation of power industry will; (a) bring many additional generating station on to the network, (b) allow shipping of real power along different paths and in different directions than what they were designed for, (c) allow a rapid change in power dispatch due to competition of selling power to different customers as they change generating companies as often as every hour, (d) let power be transferred, wheeled, and interchanged. The absence of the knowledge that there is sufficient reactive reserve in each reactive reserve basin due to the lack of knowledge that additional reactive power supply may be necessary will also contribute to voltage collapse in a deregulated power industry. System failure and blackouts due to voltage instability already have been observed in Europe, Japan, Ontario Hydro, New York Power Pool, and lately many blackouts in western USA. The changes (a-d) above brought on by deregulation will only make voltage instability a more common and frequent event.

In this research, the problem of corrective control for voltage collapse problems in a deregulated power system is investigated. The study of the problems is carried out by computing the minimum set of control devices changes and the most effective corrective control changes for each equipment outage and operating changes combination predicted to cause voltage instability by Voltage Stability Security Assessment and Diagnosis (VSSAD). The set of control changes would also posture to some extent against the cumulative threats presented by all of the voltage instability causing equipment outage and operating changes. This research is divided into two stages. The first is the development procedure of Voltage Stability Security Assessment and Diagnosis discussed in [8]. The second stage is the development of Secondary and Tertiary control described in [1, 9, 16] using optimal power flow.

A revised form of the Open Access System Dispatch function within the Transmission Dispatch and Congestion Management [15] could utilize VSSAD and the secondary and tertiary control being described in this paper, but it's proposed sampling rate is far too slow to even detect occurrence of the voltage instability caused by equipment outage and operating condition change combinations until after voltage collapse has already occurred. Furthermore, it's control update rate is far too slow to correct for the voltage instability problem that is developing due to occurrence of a particular equipment outage and operating condition changes combination. Finally, there is no proposed method within the Open Access System Dispatch

[15] that could predict all single and multiple contingencies that cause voltage instability and an associated diagnostic based corrective control for each contingency. Selecting a single control  $u_0$  as proposed in [5] to prevent every possible voltage instability, thermal, and low voltage problems caused by equipment outage and operating changes (1) could have no feasible solution, (2) may be impossible to determine even if such a feasible solution exists, (3) may require large significant and costly transaction changes and (4) may require load shedding as a continuous precaution whenever voltage instability is even remotely possible.

A VSSAD based Open Access System Dispatch requires 5 second sampling and control update rate, a fast state estimator using the fast 5 second sampling rate to detect contingencies quickly, a fast 5 second control rate to implement corrective control computed proposed by a Tertiary Control for the equipment outage or transaction change predicted by VSSAD to cause instability and detected by the state estimator. The corrective control would come from a set of all corrective control computed and stored using the Tertiary Control to be used by the dispatcher for possible later implementation via secondary control when the state estimator detects the occurrence of equipment outage and operating change combinations predicted to produce voltage instability by VSSAD. The corrective control computed by the Tertiary Control is an optimal version of that proposed by the diagnostics of VSSAD for the contingency and operating change condition. VSSAD computational results are presented before the revised Open Access System Dispatch is introduced.

#### 4.0 VSSAD Numerical Results

##### 4.1 Contingency Selection and Ranking

The Voltage Stability Security Assessment and Diagnosis is carried out using the following; (a) AVCASP program to compute the voltage collapse region, voltage control area, and reactive reserves basin; (b) CONRES program to perform the single and double contingency analysis; and (c) a PTI load flow to perform the diagnostic analysis in a non-automated fashion.

The test is performed on a 162 bus system shown in Figure 1. This system represents a reduced model of Iowa, Nebraska, Minnesota, and S. Dakota systems and was obtained from a University of Washington data base. This model was the only model in this database where a significant subset of generators had finite reactive limits and thus could experience loss of control voltage instability. To obtain the coherency parameter alpha and for identifying voltage collapse regions and reactive reserve basins, Q-V curves were computed at every bus in the model with the voltage rating above 20 KV. The test value of alpha  $\alpha$  obtained from AVCASP, that would make every bus in each voltage control area have the same Q-V curve minima and the same set of generators in their reactive reserves basin, was

found to be  $\alpha = 0.2224$ . The knowledge development task of finding voltage collapse regions, voltage control areas, and the reactive reserve basins associated with each voltage collapse region is provided as outputs of AVCASP. The results are shown in Table 1 in the Appendix of [20].

Having knowledge about the coherent bus groups or voltage control areas that experience unique voltage collapse problem will help developing the single and double contingency analysis. The contingency analysis is performed by ranking  $N = 5$  worst contingencies for each reactive reserve basin. The contingencies are ordered and presented in terms of the largest percentage of the base case reactive reserves exhausted by each contingency. The contingency ranking for voltage collapse region # 35 for single contingencies is given in Table 4.1. The voltage control areas that belong to the voltage collapse region are given at the top left of the table. Each voltage control area is specified by the number and the name of the bus given. Below the voltage control area is the reactive reserve basin. The reactive reserve basin is specified by specifying each of the generators that belong to it in terms of the generator bus number and name as well as their continuous rating reactive capacity in MVAR's, their base case reactive reserves in MVAR's, and the voltage control area number the generator belongs to. These voltage control areas are connected by 161 KV lines and the reactive reserve basin at buses 121, 118, 73, and 101 are generating stations that surrounded the voltage collapse region in the 162 system. At the end of reactive reserves basin information, the total base case reactive reserves in the specified voltage collapse region is given. The contingency ranking results for that reactive reserves basin follows the reactive reserves basin information. The contingencies are ordered and presented in terms of the largest percentages of the base case reactive reserves exhausted by each contingency. The first column indicates the contingency case number along with description of the contingency showing whether it is a line outage or generator outage. The second column gives the percentage of the base case reactive reserves available after the contingency. The following two columns give the generator bus name and its reserves after the contingency. The final column contains the percentage of the base case reactive reserves in that voltage control area that are unexhausted after the contingency has occurred. The last column is the most important to indicate how close this voltage collapse region is to loss of control voltage instability caused by that contingency since percentage of voltage control areas with zero reserves is the best proximity measure for assessing the proximity to loss of control voltage instability.

There were 291 single contingencies simulated. These 291 contingencies consist of all single line and generator outages on a 162 bus system. Only 90 double contingencies were identified from combinations of single generator and line outages that exhausted all but 25% of the reserves in some reactive reserve basin based on results similar to those in Table 4.1 for each reactive reserve basin. Similar results to Table 4.1

are given in Table 4.2 for the double contingency analysis for the same voltage collapse region and the same reactive reserve basin. The double contingencies consist of double generator outages, double line outages, and a combination of generator outages and line outages. Tables 4.3 and 4.4 shows the single and double contingencies respectively that had the most affect on the largest number of agents. In both tables, the first column shows the contingency case number, the second column represent the kind of the contingency (line outage or generator outage), and the third column shows the number of agents where the contingency was among the worst five contingencies. Table 4.3 shows that the single contingencies identified as being among the five worst single contingencies in the most reactive reserve basins make up each of the worst double contingencies in Table 4.4. This is exactly what is obtained from studies of large power system models.

#### 4.2 Diagnosis for Loss of Control Voltage Instability Contingencies

Twenty seven out of the ninety double contingencies simulated did not have a load flow solution. These twenty seven double contingencies were resimulated and eighteen of them solved when the reactive limits on all the generators in the network were ignored. These eighteen double contingencies were associated with loss of control voltage instability based on our definition of loss of control voltage instability in Section 3.4.1 because each exhausted all the reactive reserves in a critical reactive reserve basin. The remaining nine of these twenty seven contingencies were associated with clogging voltage instability. Nine out of eighteen loss of control voltage instability contingencies caused at least one or more voltage collapse regions to have negative reserves in its associated reactive reserves basins. The results are presented in Table 4.5. The first two columns of the table give the contingency case number and the double contingency description, the last column gives the number of voltage collapse regions with negative reserves in its reactive reserves basin. A summary of results of loss of control voltage instability for the one voltage collapse region found to be most affected by each contingency in Table 4.5 is given in Table 4.6. The voltage collapse region number is given in column 1. Columns 2, 3 represents the voltage control areas, and the reactive reserve basin associated with that voltage collapse region. The base case reactive reserves in the reactive reserves basin is given in column 4, and the last two columns indicates the percentage of the reactive reserves after the contingency and the contingency case number that caused the instability.

The contingency associated with the case number can be found from Table 4.5. The reactive reserve basins in Table 4.6 are nested reactive reserve basin and they form a root of tooth as can be observed by observing the size of the reactive reserve basins and the generators that belong to each as one proceeds down the table. The smallest reactive reserve basins were the most affected reactive reserve basin for the less severe

contingencies that requires smaller amounts of additional reactive reserves. Contingencies that require more reactive reserves to be added most severely affected the larger reactive reserve basins in the tooth. The six voltage collapse regions shown in Table 4.6 all had negative reactive reserves in their reactive reserves basins for the nine loss of voltage control contingencies with negative reserves shown when generator reactive limits are ignored.

A diagnostic study is now performed using the PTI load flow. The result is presented in Table 4.7. The first column shows the generator bus numbers in all of the reactive reserve basins most severely affected by these nine contingencies in Table 4.6. The next nine columns represent each of the nine contingencies by case number and the required additional supply required to solve the nonconverged double contingency. The last two rows of the table represents the most affected voltage collapse region numbers and the generators bus number in the associated reactive reserve basin decided as most affected by that contingency. Note that the generators where reserves were added agree exactly with the generators in the most affected reactive reserve basin except that generator 99 was not in any of the reactive reserve basins. Contingencies are thus shown to sometimes require reserves outside the agents reactive reserve basin that causes voltage instability and sometimes require adding supply at generators in two reactive reserve basins. The load flow was shown to solve each of the nine contingencies if reactive reserves equal to the value of its negative reserves are added to each generator in the voltage collapse region's reactive reserve basins given in Table 4.7 for each of the above contingencies. Four of the nine diagnosed contingencies were chosen to perform the solvability problem (the corrective control problem) in Section 5.

The results show the worst contingencies that affect the larger reactive reserve basins outage two large generators in these reactive reserve basins. Generators 6, 121 and 6, 131 seems to be the most severe double generator outage contingencies. 121 and 131 are large generators with significant reactive capacity and base case reserve and therefore it makes sense that outage of these generators would have significant affect on loss of control voltage instability. These results suggest that severe contingencies cause increased network reactive losses and/or significant reduction in reserves of the affected reactive reserve basin. The results also shows that the double line outage contingencies affected the smaller reactive reserve basins and double generator outage contingencies affected the larger reactive reserve basin. Generator outages that affected these large reactive reserve basin were generators within these reactive reserve basins. The results also shows that generator bus number 121 is the most critical bus in the network. This bus needed an additional reactive supply in each one of the contingencies above, except in the case 2 and case 14. In case 2 the generator buses numbered 6 and 121 were outaged. In case 14 that affected voltage collapse region number 3, generator bus 121 does not belong to its reactive reserves basin.

#### 4.3 Diagnosis for Clogging Voltage Instability Contingencies

Nine out of the twenty seven double contingencies did not solve the load flow even when infinite reactive supply were provided to every generator in the network. Some of these nine contingencies, listed in Table 4.8 produced clogging voltage instability. The PTI load flow package is used to study these double contingency cases. Reducing real and reactive power flow on paths with large reactive losses and voltage decline that supply real and reactive power to appropriate agent voltage collapse regions will eventually obtain a load flow solution. The agent voltage collapse regions, that are most severely impacted by both single contingency components of a double contingency, are agent voltage collapse regions where all real and reactive load is shed and where an equal amount of active generation is shed. This load and generation shedding is performed one at a time for each of the agent voltage collapse regions ranked as most severely impacted by the double contingency (based on the results from simulation of its single contingency components). This load and generation shedding is continued until a load flow solution is obtained when reactive limits on all generation are ignored. If reactive power on any generators exceed reactive capability, then reactive capability is added until a solution is obtained when reactive limits are enforced. This procedure was applied to three contingencies in Table 4.8 where the load shedding and generation shedding cured the problem. The amount of load shedding required at various buses and generation shedding required at the generators in various agent voltage collapse regions is shown in Table 4.9, 4.10, and 4.11. The agent voltage collapse regions in the order that load and generation was shed is also shown. In case 8, Table 4.9 shows the load shed equals the generation level on the outaged generators. In other cases, Table 4.10 and 4.9 show the total load and generation shed is equal. The load flow solution are obtained in each case after the amount of load and generation is shed. The procedure did not work for case 5 that outaged generators 73 and 76. Generators 73 and 76 are the only two generators in a reactive reserve basin that causes a cascading voltage collapse problem. Reducing generation and load was required in such a large number of agent voltage collapse regions that the action was so drastic that it was felt that adding an SVC or synchronous condenser to its agent was necessary rather than load and generation shedding. Since Section 5 results will obtain corrective controls that eliminate the need to perform load and generation shedding, and since these results in this chapter seeks contingencies where such action might be successful, the results for case 5 were never obtained. For the remaining two cases of Table 4.8 the procedure did not work because these double line outaged caused the network to be split into two networks.

## 5.0 Open Access System Dispatch Security Constrained Optimization

### 5.1 VSSAD and Minimum Control Solvability Combination

The Open Access System Dispatch problem is composed of Contingency Selection Module and a Constrained Optimization Module as described in section 2. The Contingency Selection Module finds all combinations of all equipment outage and one or more transfer and wheeling transactions violation of minimum reactive reserve limits on some reactive reserve basin or cause clogging voltage instability for some agent. VSSAD can identify the combinations of an equipment outage with one or more transfer and wheeling transactions that either

1. violate minimum reactive reserve limits on one or more reactive reserve basins. VSSAD will automatically detect the reserve basins with reactive limit violations as well as generators where added reactive supply would cause satisfaction of all violated reactive reserve basin minimum reactive limits. VSSAD would also determine the level of additional reactive reserve or reactive supply capability needed on each of these generators to avoid reactive limit violations;
2. exhaust all reactive reserves on one or more reactive reserve basins, do not have a load flow solution when reactive limits are enforced, but have solution when reactive reserve level increases are added on specific generators, SVCs, or synchronous condensers. VSSAD would also determine the level of additional reactive reserve or reactive supply capability that must be added to each of these generators to obtain a load flow solution;
3. that do not have a load flow solution when reactive limits are enforced or when they are ignored, but have solution when one or more transactions are modified or curtailed, or load and generation is shed at appropriate buses. VSSAD would determine the transaction to be curtailed and the level of curtailment, the transaction to be eliminated, and the level of load and generation to be shed.

This development of VSSAD capability is a very large contribution because without VSSAD (a) it takes 15 hours engineering and computing time of trial and error by an engineer per equipment outage to obtain a solution when no solution exists, (b) there is no guarantee that the trial and error solution correctly diagnoses the cause, and (c) there is no guarantee the suggested action has the minimal affect on current power system operation. Even though VSSAD provided changes may be diagnostic in determining and verifying the actual cause, it is not clear how the needed reactive reserve can be obtained. It is also not clear (1) what is the minimum set of control actions that are most effective in providing the reactive reserve or reducing network losses in particular agents and (2) what are the control changes that both

provide the reactive reserves or reduce the reactive losses and yet require a minimum cost for ancillary services for each equipment outage and transaction change combination identified by VSSAD. Additional reactive reserves are needed in particular agents either because a load flow solution can not be obtained due to loss of control voltage instability without additional reserves on specific generators or because minimum reactive reserve levels on one or more reactive reserve basins are violated after an equipment outage and operating change combination. VSSAD recommends curtailing one or more transactions by cutting real and reactive load in a voltage control area and active generation in its reactive reserve basin generators to reduce the network losses that cause clogging voltage instability for that agent or voltage control area. It is not clear that such a drastic action as curtailing one or more transactions of power marketers and generators is actually necessary to obtain a solution. If transaction curtailment isn't necessary or if other control actions can reduce the transaction curtailments, what are the minimum set of controls, the most effective set of control changes, and the minimum ancillary cost for the set of control actions that will totally or partially eliminate the transaction curtailment.

Two optimization problems are posed; for (a) adding reactive reserves and (b) for minimizing transaction curtailments:

#### 1) Minimum Control Solvability Problem.

A minimum control solvability problem either (a) obtains the reactive reserves on generators in the amounts VSSAD determines are needed to obtain solution of the load flow or so that minimum reactive reserve basin reserve requirements are met or (b) obtains solution of the load flow without curtailment of the set of transactions determined as needed via VSSAD for a solution to exist. The controls include (1) adding switchable shunt capacitors, generators, or synchronous condensers close to the generators needing additional reserves (loss of control voltage instability) or the voltage collapse region needing reactive supply (clogging voltage instability); (2) adjusting AVR voltage set points to reduce reactive power pickup on generators that need reactive reserves (loss of control voltage instability) or to increase reactive generation supply rate out of generators, SVCs, or synchronous condensers outside and sometimes inside voltage collapse regions needing reactive supply (clogging voltage instability); (3) adjusting tap position on distribution and subtransmission level under load tap changers to reduce distribution level voltage and load (loss of control voltage instability) or to adjust tap position to avoid tap position limits and allow more effective pumping of reactive into the voltage collapse region needing reactive supply (clogging voltage instability); and (4) reducing active generation out of generators that need reactive reserves (loss of control voltage instability) or redispatch active generation from one set of generators to another set of generators to relieve reactive clogging on particular paths to the voltage collapse region needing reserves.



## 2) Minimum Ancillary Services Cost Problem

The minimum ancillary services cost problem has an objective of minimizing the cost of ancillary services required to correct a clogging or loss of control voltage instability problem while maintaining solvability for a particular VSSAD determined equipment outage and operating change combination. A minimum ancillary cost problem uses the solution of the minimum control solvability problem to achieve as a starting solution that is both feasible and solvable in terms of satisfying reactive reserve basin reactive reserve constraints, thermal constraints and voltage constraints. The objective is to adjust controls (1-4) to minimize ancillary services cost to the ISO. This minimum ancillary services cost can also further attempt to further reduce the number of controls used in the minimum control solvability problem solution.

The minimum control solvability and the minimum ancillary services cost problems are the slave problems in a Benders decomposition. There is a slave problem for each equipment outage and operating change combination that VSSAD determines needs reserves to meet minimum reactive reserve basin requirements, to avoid loss of control voltage instability or that needs reactive supply to avoid clogging voltage instability. The control determined out of the minimum control solvability and minimum ancillary services cost problem sequence is  $u_j$ .

The slave problem is generally just one optimization problem not two as discussed above. One set of objectives is (a) to obtain some control change that obtains a solution and (b) find the minimum control set that will obtain that solution when no solution exists without the control change. These two objectives are met by the minimum control solvability problem. An additional objective is to find an even narrower set of controls that are effective in obtaining a load flow (solvability and feasibility) solution and minimize the cost of ancillary services. This third objective is met from the minimum ancillary services cost problem. It was thought that one optimization problem could not achieve all of these objectives, and therefore a sequence of optimization problems is proposed. The minimum control solvability problem is much like the optimizations used to obtain feasible starting solutions for an interior point algorithm. The minimum control solvability is seeking a feasible starting solution for the optimization but also one that has a load flow solution.

The master problem attempts to adjust the control  $u_0$  to posture the system so it is not as vulnerable to the set of equipment outage and operating change combinations via minimizing the ancillary services cost increase and holding it under a certain maximum for each equipment outage and operating change combination identified as causing loss of

control or clogging voltage instability in some voltage collapse region and its reactive reserve basin.

A block diagram showing the relationship of the VSSAD program, the minimum control solvability problem, minimum ancillary cost problem, and the master problem is given in Figure 2.

## 5.2 Minimum Control Solvability Problem

The minimum control solvability problem depends on whether clogging or loss of control voltage instability occurs because

- VSSAD recommends adding reactive reserves  $Q_{Gi}^{*j}$  to each generator  $i \in I_j$  for loss of control voltage instability for the  $j^{\text{th}}$  equipment outage and operating change combination.
- VSSAD recommends reducing a set of a transfer or wheeling transaction for clogging voltage instability for the  $j^{\text{th}}$  equipment outage and operating change combination.

The procedure used in VSSAD to determine the precise recommendation for any equipment outage or operating change is given in section 3 and omitted here. The objective of the minimum control solvability problems for any VSSAD recommendation is to completely avoid having to take VSSAD recommended action by adjusting the voltage controls and possibly as a last resort adjusting active power dispatch. The minimum control solvability problem for loss of control voltage instability is now formulated. The minimum control solvability problem for loss of control voltage instability must add reactive generation and generation capacity  $Q_{Gi}^{*j}$  to each generator  $I_j$  by modifying  $Q_{Gi \max}^0$  and  $Q_{Gi}^0$ .

$$Q_{Gi}^j = Q_{Gi}^0 + Q_{Gi}^{*j} \quad (5.1)$$

$$Q_{Gi \max}^j = Q_{Gi \max}^0 + Q_{Gi}^{*j} \quad (5.2)$$

where  $Q_{Gi}^{*j}$  is the reactive supply added at generator  $i$  in order to obtain a load flow solution for the  $j^{\text{th}}$  equipment outage and operating changes.  $Q_{Gi}^j$  is the generation capacity after  $Q_{Gi}^{*j}$  is added to the base case.  $Q_{Gi \max}^0$  and  $Q_{Gi \max}^j$  is the maximum reactive generation in the base case at generator  $i$

and the maximum reactive supply at generator  $i$  after  $Q_{Gi}^{*j}$  is added as VSSAD recommends to obtain a solution for the  $j^{\text{th}}$  equipment outage and operating change respectively.

If  $Q_{Gi}^0 = Q_{Gi\max}^0$  is the reactive supplied by generator  $i$  before reactive supply capability is added to obtain a load flow solution, (5.1) is reactive generation after the equipment outage and operating change  $j$  occurred. Use  $Q_{Gi}^j$  as a starting point for the optimization problem. These modifications are needed so that both the load flow and optimal power flow have a solution to start the optimization that they would not otherwise have without adding reserves  $Q_{Gi}^{*j}$  to generators  $i \in I_j$  for equipment outage and operating condition change  $j$ . The minimum control solvability problem for loss of control voltage instability will minimize this added reactive generation  $Q_{Gi}^{*j}$

$$\sum_{i \in I_j} \left( Q_{Gi}^j - Q_{Gi}^0 \right)^2 = \sum_{i \in I_j} \left( Q_{Gi}^{*j} \right)^2 \quad (5.3)$$

subject to the reactive reserve basin, thermal, voltage and control constraints that specify three successively larger control sets. The constraints are

$$P_{Gi} - P_{Di} = e_i \left[ \sum_{j=1}^n (G_{ij}e_j) - B_{ij}f_j \right] + f_i \left[ \sum_{j=1}^n (G_{ij}f_j) + B_{ij}e_j \right] \quad (5.4)$$

$$Q_{Gi} - Q_{Di} = f_i \left[ \sum_{j=1}^n (G_{ij}e_j) - B_{ij}f_j \right] - e_i \left[ \sum_{j=1}^n (G_{ij}f_j) + B_{ij}e_j \right] \quad (5.5)$$

$$P_{Gi\min} \leq P_{Gi} \leq P_{Gi\max}; i=1,2,\dots,M \quad (5.6)$$

$$Q_{Gi\min} \leq Q_{Gi} \leq Q_{Gi\max}; i=1,2,\dots,M \quad (5.7)$$

$$V_i^2 \leq e_i^2 + f_i^2 \leq V_{i\max}^2; i=1,2,\dots,n \quad (5.8)$$

$$I_{ij\min}^2 \leq \left[ (e_i - e_j)^2 + (f_i - f_j)^2 \right] \leq I_{ij\max}^2; ij=1,2,\dots,Br \quad (5.9)$$

$$A_{t\min} \leq A_t \leq A_{t\max}; t=1,2,\dots,T \quad (5.10)$$

$$C_{sh\min} \leq C_{sh} \leq C_{sh\max}; sh=1,2,\dots,S \quad (5.11)$$

$$RR_{r\min} \leq \sum_{i_r \in RRB_r^*} Q_{Gi}^j - Q_{Gi\max}^j; r=1,2,\dots,R \quad (5.12)$$

where:

$M$  = number of generator buses in the network

$n$  = number of buses in the network

$Br$  = number of branches connected between buses in the network

$T$  = number of transformers connected between buses in the network

$S$  = number of shunt capacitors in the network

$RR_{r\min}$  is the minimum reactive reserve in each of the reactive reserve basins

$R$  = number of reactive reserve basins ( $RRB_r$ ), and  $i_r$  is the number of the generators in each reactive reserve basin.

The minimum control solvability problem is really a series of problems with successively different control sets. There are four control sets proposed:

1. generator AVR set point voltage on generators  $i \in I_j$  and generators near  $i \in I_j$ ;
2. switchable shunt capacitors electrically close to generators  $i \in I_j$ ;
3. under load tap changer tap position;
4. active generation at generators  $P_{Gi}$ ;  $i \in I_j$  and generators near set  $i \in I_j$ .

The control sets used are 1 and 2, 1-3, and 1-4 where if adding a different control didn't result in a significant improvement in

obtaining a solution, it was no longer used in an even larger control set that added control of another set of control devices. There are six very major differences in this optimal power flow problem formulation from the previous literature

$$\sum_{i \in I_j} (Q_{G_i}^{*j})^2 \quad (5.13)$$

- A. a set of reactive reserve basin constraints that assure load flow solution when loss of control voltage instability occurs. Since tap changers and capacitors are treated as continuous variables in an optimal power flow, the Hessian of the optimal power flow problem is not singular when the load flow model and the actual power system are experiencing instability. If tap changers and capacitors were treated as discontinuous variables, and the maximum excitation limiter action was more accurately reflected in the optimal power flow, there would never be a solution to the optimal power flow that could not be a solution to the load flow when clogging voltage instability is assumed to be impossible on a particular system. The reactive reserve basin constraints with very modest levels of reactive reserve (10 MVAR or less on each) helps guarantee that the optimal power flow has no solution when the load flow has no solution due to loss of control voltage instability. This is true because if all generators on a reactive reserve basin are at reactive limits, no load flow solution may exist and the optimal power flow has no solution due to violation of the reactive reserve basin constraint;
- B. when the optimal power flow has a solution (since every reactive reserve basin has reactive reserves and thus loss of control voltage instability can not occur on this system), an optimization is possible that attempts to maintain a stable load flow solution while minimizing the VSSAD recommended addition of fictitious generators with fictitious reactive supply capability. This is impossible without reactive reserve basin constraints on all reactive reserve basins from (1) above since one could not be sure that optimal power flow solution would imply a load flow solution and vice versa for a system that can only experience loss of control voltage instability. VSSAD recommended action of adding fictitious generators at particular buses  $i \in I_j$  with starting generation  $Q_{G_i}^{*j}$  assures the load flow has a solution and that the optimal power flow with reactive reserve basin constraints has a starting solution. The reactive generation at fictitious generators  $Q_{G_i}^{*j}$  and that at the actual generators  $Q_{G_i}^0$  are added to produce equivalent generators that satisfy (5.1) and (5.2) or the actual and fictitious generators each satisfy (5.1) and (5.2);
- C. a performance index that is quite different from optimal active and optimal reactive dispatch (total active or reactive network losses). This performance index minimizes a quadratic performance measure

- D.  $Q_{G_i}^{*j}$ ,  $i \in I_j$  are added via adding fictitious generators in the model after the equipment outage to obtain solution to the load flow and a starting point for the optimization model that also has the equipment outage. Fictitious generators were not added into agent reactive reserve basin constraints that quite possibly could have included this fictitious reactive generation because from (5.1) and (5.2) one would have not changed the reserve levels in a reactive reserve basin by adding reactive generation to the reactive generation and reactive generation capacity of the equivalent generators (composed of actual and fictitious generators). Using a modest level of 10 MVARs on the reactive reserve basins that could but do not contain these fictitious generators suggests that these reactive reserve basin reserve levels must be maintained as the optimization proceeds (using the network model where the contingency has occurred) so that load flow solvability is maintained. These reactive reserve constraints maintain these very modest reactive reserves as the fictitious generators reactive generation is reduced to zero and the reserves on these reactive reserve basin generators would have been driven to zero and negative without the reactive capability constraints on each generator and these reactive reserve basin constraints on these reactive reserve basin;
- E. the reactive reserve basin constraints on other reactive reserve basins are set at modest level of reserves to prevent loss of control voltage instability and thus voltage collapse on these other reactive reserve basins. These reactive reserve basin constraints allow borrowing of reactive reserve on all reactive reserve basins not needing additional reserves but prevents the solution from exhausting all reactive reserves in any reactive reserve basin causing it to produce a voltage collapse;
- F. the use of four different control sets of increasing number of control sets rather than one that contains all four control sets allows the problem to select a minimum control set.

This set of optimization problems may be viewed as attempting to reduce the precontingency level  $Q_{G_i}^0$  rather than add the

reactive supply capability  $Q_{G_i}^{*j}$  on a set of generators  $I_j$  in the load flow model so that will obtain a load flow solution after the contingency. If the performance index is not zero with control set (1), then control set (1) and (2) is used; and if the performance index is still not zero using control sets (1) and (2), then control set (1), (2), and (3) is used since zeroing the performance index assures solvability with reactive limits

$Q_{Gi\max}^0$  enforced. Control set (1), (2), (3), and (4) is used as a last resort. Control set (1), (2) and (3) has solely ancillary services cost. Control set (4) allows modification or curtailment of transfer and wheeling transactions which is an anathema to power marketer and other generation companies whose business depends on having unfettered and uninterrupted transmission service. These power marketer would receive the cost of the transaction interruption and the profit they would have received if their transaction had been completed, plus some possible penalty which can be a fairly high cost to an ISO. The power marketer may even sue the ISO for damages if the transaction interruptions are frequent. Control set (4) is considered the last choice.

The minimum control solvability problem for loss of control voltage instability attempts to find the minimum set of control changes that provide a solution to the load flow and hopefully allow for stable operation if sufficient reactive reserve margin is achieved for the reactive reserve basins found deficient for a specific equipment outage and operating change combination. The minimum control solvability solution for loss of control voltage instability can also be used to add reactive reserves on to generators  $i \in I_j$  to allow (1) reactive reserve basins to remain within minimum reserve requirements  $RR_k = 10$  MVAR after an equipment outage and operating change combination  $j$ , (2) allow the load flow to have a solution, (3) avoid loss of control voltage instability, and (4) obtain the reactive reserves from reactive reserve basins that had excess reactive reserves or more likely from capacitors that switch in or tap changers that do not pump reactive power into the distribution and subtransmission system.

Clogging voltage instability occurs when a voltage control area can't obtain needed reactive supply after an equipment outage or operating change occurs because the reactive supply flowing from generators, SVCs, synchronous condensers never reach the voltage collapse region. The line outage may open an important path for reactive flow to the voltage control area causing clogging voltage instability due to excessive network reactive losses on the other paths to that voltage collapse region (agent). The operating change may add real and reactive flow on heavily loaded paths or interfaces with rapidly increasing network reactive losses that absorb reactive power that would otherwise flow to and supply reactive needs in the voltage collapse region (agent for clogging voltage instability).

Minimum control solvability for clogging voltage instability for a particular equipment outage and operating change combination has a different performance index than the minimum control solvability for loss of control voltage instability because VSSAD recommended remedy is different. VSSAD recommends cutting load at buses in voltage collapse region  $j$  and active generation at generators in  $RRB_j$  associated with that voltage control area and thus curtail one or more

wheeling transactions which would result in a modification of load flow data

$$P_{L_i} = P_{L_i}^0 - \alpha_i P_{\text{wheeling}} \quad i \in VCA_j, j=1,2,\dots,J \quad (5.14)$$

$$\sum_{i=1} \alpha_i = 1 \quad (5.15)$$

$$P_{G_i} = P_{G_i}^0 - \beta_i P_{\text{wheeling}} \quad i \in RRB_j, j=1,2,\dots,J \quad (5.16)$$

$$\sum_{i=1} \beta_i = 1 \quad (5.17)$$

Where  $P_{L_i}^0$  and  $P_{L_i}$  are the power at load bus  $i$  before and after the wheeling transaction is curtailed respectively and  $P_{\text{wheeling}}$  is the amount of power wheeling curtailed.  $P_{G_i}^0$  and  $P_{G_i}$  are the power at generation bus  $i$  before and after the wheeling transaction is curtailed respectively.  $\alpha_i$  and  $\beta_i$  are the bus participation factors on the curtailed load and generation, respectively.  $VCA_j$  and  $RRB_j$  are the voltage control area and its reactive reserve basin of the  $j^{\text{th}}$  agent respectively

The minimum control solvability performance index minimizes

$$\sum_{j=1}^J \left[ \sum_{i \in VCA_j} \left( P_{L_i} - P_{L_i}^0 \right)^2 + \sum_{i \in RRB_j} \left( P_{G_i} - P_{G_i}^0 \right)^2 \right] = \sum_{j=1}^J \left( \sum_{i \in VCA_j} \alpha_i^2 + \sum_{i \in RRB_j} \beta_i^2 \right) P_{\text{wheeling}}^2 \quad (5.18)$$

subject to the load flow equation equality constraints (5.4, 5.5) with generation and loads specified by voltage (5.8), thermal (5.9), and reactive reserve basin (5.12) constraints, and control constraint set (5.6, 5.7, 5.10, 5.11) corresponding to control sets (4), (1), (3) or (2). These constraints are the same as those in the case of loss of control voltage instability (5.4 – 5.12). This performance index for the minimum control solvability for wheeling reduction solved clogging voltage instability should be zero requiring  $P_{\text{wheeling}} = 0$  if a solution to a minimum control solvability exists for a particular control set. Without  $P_{\text{wheeling}}$  being zero, there is no load flow solution for the  $k^{\text{th}}$  equipment outage and operating change combination. Using successively larger control sets (1), (1 and 2), (1, 2, and 3) and (1, 2, 3 and 4) sequentially should obtain a solution.

A second VSSAD recommended action is to curtail one or more transfer transactions

$$P_{G_i} = P_{G_i}^0 - \alpha_i P_{\text{transfer}} \quad i \in E_j, j=1,2,\dots,J \quad (5.19)$$

$$\sum_{i \in E_j} \alpha_i = 1 \quad (5.20)$$

$$P_{G_k} = P_{G_k}^0 - \beta_k P_{\text{transfer}} \quad k \in I_j, j=1,2,\dots,J \quad (5.21)$$

$$\sum_{k \in I_j} \beta_k = 1 \quad (5.22)$$

where  $E_j$  is the set of exporting generators and  $I_j$  is the set of importing generators for the transfer of  $P_{\text{transfer}}$  from  $E_j$  with participation factor  $\alpha_i$  to  $I_j$  with participation factor  $\beta_k$ .

The minimum control solvability performance index that curtails the transfer transactions is

$$\sum_{j=1}^J \left[ \sum_{i \in E_j} (P_{G_i} - P_{G_i}^0)^2 + \sum_{k \in I_j} (P_{G_k} - P_{G_k}^0)^2 \right] = \sum_{j=1}^J \left( \sum_{i \in E_j} \alpha_i^2 + \sum_{k \in I_j} \beta_k^2 \right) P_{\text{transfer}}^2 \quad (5.23)$$

subject to the load flow equation constraints, reactive reserve basin, thermal, and voltage inequality constraints and the control constraints corresponding to control sets (1), (1 and 2), (1, 2, and 3) and (1, 2, 3 and 4). These constraints are the same as in (5.4 – 5.12). The performance index for the minimum control solvability transfer reduction solved clogging voltage instability should be zero requiring  $P_{\text{transfer}} = 0$  if a solution to the minimum control solvability for clogging voltage instability exists for a particular control set. If  $P_{\text{transfer}} \neq 0$ , VSSAD indicates there would be no load flow solution for that specific equipment outage and operating change combination. Using successively larger control sets, there should be a solution to this minimum control solvability for clogging voltage instability problem.

The minimum control solvability problem for clogging voltage instability has unique attributes (A, E, F) of the minimum control solvability problem for loss of control voltage instability. Attributes (B, C) for the minimum control solvability problem for clogging voltage instability are similar to those for the minimum control solvability problem for loss of control voltage instability except that we have to shed

generation and load to obtain a load flow solution in attribute B rather than adding fictitious reactive generators so our load flow and optimal power flow have solution when reactive reserve basin constraints are imposed. The performance index, addressed in attribute C, is again quite different than for optimal active and optimal reactive dispatch but is a quadratic measure of the shed generation and load for wheeling transaction or the curtailed transfer level for a transfer transaction. The solution to the optimal power flow occurs when the level of shed load and generation in a wheeling transaction or the level of the curtailed transfer for a transfer transaction is zero. The performance index requires complete elimination of the VSSAD recommended actions while starting the optimization from the VSSAD recommended solution.

Note that there are three minimum control solvability subproblems involving three successively larger control sets (1), (2), and (3) are

- The minimum control solvability for loss of control voltage instability.
- The minimum control solvability for wheeling reduction solved clogging voltage instability.
- The minimum control solvability for transfer reduction solved clogging voltage instability.

### 5.3 Numerical Results

Here we conduct numerical simulation to provide some quantitative performance indices for the developed algorithm. The purpose of so doing is to test the algorithm developed and to find the kind and effectiveness of control change that will obtain solution to the solvability problem. The validity of the proposed method is demonstrated on the 162 bus system shown in Figure 1 for the study of voltage instability problems. Seven cases are chosen from the VSSAD contingency analysis of Section 3. The first four of these cases in Table 5.1 and found in Figure 1 caused loss of control voltage instability due to equipment outage. The four cases were chosen so that two are double generator outages affecting large reactive reserve basin agents in the same root and two are double line outages affecting small reactive reserve basin agents in that root. The remaining three cases in Table 5.1 and observable in Figure 1 caused the system to experience clogging voltage instability. Two are double line outages and one is a double generator outage. Double contingencies that caused network separation or that outaged all generators in an agent were not investigated since VSSAD did not have the ability to recommend system commitment actions such as adding generators or lines. No system dispatch actions in control sets (1-4) are sufficient to correct voltage collapse for such contingencies and thus no VSSAD recommendations were made and no minimum control solvability problem could be formulated. For these seven cases where a Minimum Control Solvability problem is formulated,

the objective is not to just obtain a load flow solution where none existed since the VSSAD recommended action would obtain a load flow solution. The objective of the minimum control solvability problem for loss of control voltage instability is to achieve solvability without the impossible or onerous action VSSAD recommends. Adding reactive capacity on particular generators is impossible, but adding capacitors, reducing reactive supply on generators exceeding reactive limits by reducing their generator excitation system voltage setpoints, reducing the reactive pumped to the distribution network from these generators by reducing tap position on certain under load tap changers, increasing tap position on other tap changers that pull reactive from other generators, and adding shunt capacitors in the distribution network will be proven to provide solvability without the impossible VSSAD recommendation of adding reactive capacity on the generators shown in Table 4.7.

The objective of the minimum control solvability problem for clogging voltage instability is to achieve solvability without load and generation shedding that would be so onerous in a deregulated system that desires competition and the ability to undertake transactions without significant concern for maintaining stability and security, and certainly without the concern that the transaction would be curtailed as the only method of preventing a blackout. The minimum control solvability problem is proven to eliminate the need to perform load and generation shedding by adjusting generators excitation system voltage setpoint, adjusting tap changers, adding switchable shunt capacitors, and adjusting the active power dispatch to reduce reactive network flows over critical paths and yet increase the total transfer and wheeling capability so that load and generation shedding is not necessary. It should be noted that thermal and voltage constraints are imposed in both the minimum control solvability problem for loss of control voltage instability and minimum control solvability problem for clogging voltage instability so that the corrective action does not produce voltage or thermal overload problems that must be corrected.

### 5.3.1 Loss of control voltage instability

The first four cases of Table 5.1 caused the system to experience loss of control voltage instability. The Minimum Control Solvability problem for loss of control voltage instability was applied for each selected unsolvable case. The results of the implementation of the Minimum Control Solvability problem, that minimizes and zeros the fictitious reactive supply capability added at generators shown in Table 4.7, are presented in Tables 5.2, 5.3, 5.4, 5.5 for each of the four cases. At the top of each table, the nature of the contingency is given, below it the value of the primal and dual objectives are given as well as the maximum power mismatch for the primal and dual. The convergence of the optimal power flow occurs when the duality gap between primal and dual performance indices are very small and when the mismatch on

the primal dual gradient equation is small. The results in Tables 5.2-5.5 establish the algorithm found a solution. The Tables 5.2-5.5 are arranged so that the first column gives the bus number of each actual generator, the second column represents the optimal value of the reactive supply at each fictitious and actual generators. The next three columns gives the minimum, maximum, and the initial reactive supply at each actual generator and added to each fictitious generator needing additional reactive supply as suggested by Table 4.7 in Section 4 respectively. The initial reactive supply is obtained by using the loadflow based VSSAD recommendation. The last column represent the difference between the initial value and the optimal value. The first ten rows in the Tables 5.2 – 5.5 are the generation at each of the ten generators with finite reactive generation in the 162 bus system. The last rows labeled  $f_i$  are the fictitious generators where the initial generation is added as recommended by VSSAD in Table 4.7. The fictitious generators are additional PV buses connected to the actual generators needing reactive supply through reactance of small value in  $pu$ . The bus number of the fictitious generators are 163 – 167 in Table 5.2 and are connected respectively to buses 99, 101, 114, 118, and 130 as can be seen in column 1. These values can be checked with Table 4.7 to see that the correct amount of reactive is added to the correct generators based on the VSSAD recommendation for that contingency. The same information is in Tables 5.3 – 5.5 for the other contingencies.

Note that the optimal reactive generation on all fictitious generators is zero and the initial reactive generation on all generators are within finite reactive limits, governed by  $Q_{gmin}$  and maximum  $Q_{gmax}$  respectively. Note that in

case 1, the generator outage is at bus 6 (6R1G 22) and bus 121 (C.BL 3G 24), and the critical agent in Table 4.7 contains generators 6, 121, 73, 101, 118, and 130, two of the generators in this agent were outaged and caused instability in this agent. VSSAD recommends adding reactive capability at buses 99, 101, 114, 118, and 130 as shown in Table 5.2. The optimal solution provided additional reserve at generators 101, 114, and 125, two of which are where VSSAD adds fictitious generators, and adds significant increase in reactive generation at generators 76 and 108, without causing them to get close to reactive limits. The optimal solutions is similar but not identical to VSSAD recommendation for where to add reactive reserves but borrows significant reactive from neighboring reactive reserve basins which are ignored as sources in the VSSAD recommendation.

In case 2, the generator outage is at bus 6 (6R1G 22) and bus 131 (NEBCY1G 18), the critical agent shown in Table 4.7 for case 4 contains generators 6, 131, 73, 114, 121, and 130 where the outage of the two generators 6 and 131 caused the collapse in that agent. The VSSAD recommendation in Table 5.3 adds fictitious generation at 101, 114, 118, 121, and 130. The optimization adds reactive reserve at generators at buses 101, 114, 121, and 125 and increases generation at 73, 76, and 108.

This case again showed VSSAD recommendation was not followed exactly but approximately by the optimal solution in terms of increasing the most of the VSSAD recommended generator reserves but also borrowed significant reactive from neighboring reactive reserve basins outside the reactive reserve basin root shown in Table 4.7. This is an excellent solution since borrowing reactive reserve inside the root would make the root less secure. In case 3, the contingency is the outage of line 68 (HOPE 5 161) – 69 (HOPET 5 161) and line 69 (HOPET 5 161) – 77 (WRIGT 5 161), the critical agent shown in Table 4.7 case 27 contains generators 73, 101, 118, and 121 and VSSAD recommends adding reactive reserve at buses 73, 76, 101, 118, and 121. The optimization adds reactive reserve at generators at buses 73, 99, 101, 108, 114, 121, 125, and 131 and added significant reactive generation at buses 6 and 76. In case 4, the contingency is the outage of line 55 (PLYMH 5 161) – 149 (RAUN 5 161) and line 71 (MONOA 5 161) – 85 (CARRLL 5 161), the critical agent shown in Table 4.7 case 10 contains generators 73, 101, 118, 121, and 130 and VSSAD recommends adding reactive reserve at buses 73, 101, 114, 118, and 121. The optimization adds reactive reserve at generators at buses 108, 114, 121, and 125 and significant reactive generation at buses 6 and 76. Note that in each of the four cases, the reactive generation at all generators outside the affected agent increase which is a borrowing of reactive supply from other reactive reserve basins outside the root to provide reserves in critical reactive reserve basin that makes possible experiencing the contingency without experiencing voltage instability. Reactive generation on generators in the agent could be anticipated to also increase as reactive generation at fictitious generators are zeroed by the optimization process. The fact that reactive reserves on some but not all generators in the affected agent increase rather than decrease as expected indicates that the optimization is attempting to reduce stress in the agent that will happen if reactive power generation (or real power generation) is decreased out of generators in that agent. The addition of capacitors and reduction of tap positions to reduce the pumping of reactive off the particular agent's generators allows this reduction in reactive generation on some of the affected agents generators. The success of the minimum control solvability problem solution in relieving stress retaining solvability of the load flow and allowing a stable solution to be found is checked by computing a load flow solution from this optimal solution. A load flow solution was obtained in all four cases and had a voltage profile that is far flatter and at higher voltage than in the base case before the occurrence of the double contingency that had no load flow solution.

The Tables 5.6, 5.7, 5.8, 5.9 shows some of the control changes that restore the system solvability. At the top of each table, the nature of the contingency is given, below it in each of these tables a set of control changes are defined and listed. The control change set for voltage setpoint on generators and active power are arranged such that the sequence number is in the first column and the second column represents the bus number. The optimal control value is given in the third column, and the next

three columns gives the minimum, maximum, and the initial values of the control. The initial value is that based on the load flow solution obtained based on VSSAD recommendation. The last column represents the difference between the initial value and the optimal value. In the case of transformer tap position changes, the first three columns are the sequence number, the "from" bus number and "to" bus number respectively. The last five columns represent the optimal value, the minimum value, the maximum value, the initial value and the difference between the initial and the optimal values. The set of the switchable shunt capacitors inserted are represented in a way that the sequence number is given in the first column, the second column represents the bus number where the shunt capacitor is inserted. The third column represents the optimal value and the last two columns gives the minimum and maximum values.

For case 1, 5pu or 500 MVAR of capacitive reactive supply was added as shown in Table 5.6 and net reactive generation on the ten generators increased 212.52 from Tables 5.2 for a total of 712.52 MVARs. Tables 5.6 shows the tap changers did not pump as much reactive to the load buses since the change in tap position for the most part are large and negative. This suggests that the ten generators in the system and the capacitor insertions not only supplied 285 MVARs on the fictitious generators but also supplied the load without as much use of tap changers and achieved incredibly improved voltage profile, as shown in Appendix, Table 2 of [17]. The result above showed that the control reduced generation in the agent composed of generators 6, 121, 73, 101, 118, and 130 and thus provides the reserves to relieve stress above and beyond that produced by the contingency. This discussion shows how the reserves were obtained from capacitors, borrowing from other reactive reserve basins, and from reducing the reactive power pulled off the agent's generation that was pumped to the distribution system. Allowing reactive power to flow naturally from the capacitors and generators to the distribution system reduces reactive losses in the tap changing transformers and yet maintains a very healthy voltage profile as shown in the Appendix, Table 2 of [20].

For case 2 (case 4 in Table 4.7), the ten generators added a net of 88.74 MVARs, the capacitors add 675 MVARs for a total of 753.74 MVARs, and the tap changers tap positions decreased far less than in case 1. The fact more fictitious reactive reserve generation was needed suggests a worse contingency and the capacitor insertion MVAR increase reflected that fact. The decrease in reactive generation was accompanied by decrease in the reduction of the tap changer pumping action. The results above shows that the control reduces generation in the critical agent composed of generators 6, 131, 73, 114, 121, and 130 by borrowing some reserves from other reactive reserve basins, adding significant shunt capacitive supply and again reducing the reactive pumping to the distribution system via under load tap changers. The reduction of tap changer action allows reactive power to flow naturally from the generators and

capacitors to the distribution network buses. The control greatly improves upon the base case voltage profile and prevents and corrects thermal overload problems.

For case 3 (case 27 in Table 4.7), a double line outage of HOPE5 161 to HOPET 5 161 and HOPET 5 161 to WRIGT 5 161, lines, required 700 MVARs of additional capacitors and a net reduction of 522.54 MVARs on the ten generators for a total of 177.46 MVARs to compensate for a 195 MVARs of fictitious generation. The tap changers had both a very large increase in tap positions on certain tap changers and very large decrease in tap positions on others that adjusted the direction of reactive flows to prevent the exhaustion of reactive reserves on the generators in the small agent composed of generators at buses 73, 101, 119, and 121. The large reduction in total reactive generation outside the agents was apparently possible by the tap changer action, the added capacitors, and the ability of reactive to reach the buses where it is needed from the added capacitors in the distribution network.

For case 4 (case 10 in Table 4.7), the double line outage of PLYMH 5 161 to RAUN 5 161 and MONOA 5 161 to CARRLL5 161, required no addition in capacitor reactive supply but only large increase and decrease of tap positions on a large number of tap changers, reduction of reactive generation of 1076.76 MVARs from the ten generators and the MW change on generators shown in Tables 5.5 and 5.9. The tap position changes must have allowed for such a large reduction in generation on the ten generators as well as the 225 MVARs of reactive supply on the fictitious generators. This reduction in generation is relieving stress in the affected agents so the fictitious generators are not needed outside that agent so that the total reactive generation on actual generator can be reduced rather than increased by the 225 MVARs of the fictitious generators. This is extraordinary performance for a control. This is again a very different corrective action for voltage instability on the agent composed of generators 73, 101, 118, 121, and 130. The solution in case 4 is very different than cases 1-3 because no capacitors are added and active power generation dispatch changes are required as seen in Table 5.9. This was obtained because when capacitors were added as part of control set 2 the PTI load flow would not solve after the optimal solution was obtained. Therefore control set 1, 3 and 4 with active power generation changes along with tap position changes and generator voltage set point changes was tried. The solution apparently corrected a clogging voltage instability problem that was being produced with addition of capacitors and that was not being eliminated by reactive reserve basin constraints in the optimal power flow. The solution obtained via power flow changes and tap changer tap position changes so changed the network active and reactive flow that a total reduction of 264.36 MVARs in reactive losses (that was producing clogging voltage instability) was achieved that allowed a reduction of 225 MVARs of fictitious generation. An increase of 27.95 MVARs in reactive reserves was possible on the critical agent composed of generators 73,

101, 118, 121, and 130. This added reserves on the critical agent corrected the loss of control voltage instability on that agent by zeroing generation out of fictitious generators and then relieving stress caused by reactive generation on agent generators. This solution allowed a load flow solution to be obtained using the minimum control solvability solution.

### 5.3.2 Clogging Voltage Instability

The last three cases of Table 5.1 caused the system to experience clogging voltage instability. The results of the Minimum Control Solvability for clogging voltage instability problem that minimizes the transaction curtailment are presented in Tables 5.10, 5.11, 5.12. The VSSAD recommended changes, that provide a load flow solution and starting feasible optimization problem solution, are given in Table 4.9, 4.10, 4.11. The optimization attempts to find a solution using control set 1, control set 2, and control set 3 control changes, but this was not possible.

The formulation of the minimum control solvability problem for clogging was modified slightly to permit ease of implementation using the interior point method algorithm that requires all variables to be positive. This modification also took into account the fact that control set 4, that results in redispatch of active generation, would almost certainly be required to obtain solution to the minimum control solvability problem for clogging voltage instability. The reformulated problem

1. accomplished the VSSAD recommended load and generation shedding shown in Table 4.9 – 4.11 by adding fictitious generators connected at each load bus though a small reactance. The initial generation  $P_{fi}$ , the fictitious bus number and the load bus it is connected to (given in parenthesis), the optimal value of  $P_{fi}$  and the minimum and maximum  $P_{fi}$  values are also given in Tables 5.10-12. If an optimization solution is obtained, the value of  $P_{fi}$  at each fictitious bus is zero as is obtained for all three contingencies;
2. the performance index used

$$\sum_{i \in F} (P_{fi})^2 \quad (5.30)$$

where  $F$  is a set containing all fictitious generators would attempt to zero the fictitious generation at these fictitious generators and thereby eliminate the wheeling curtailment suggested by VSSAD;

3. the value of  $P_{gi}$  at the actual generators in the system are also control variables if control set 4 is used and the



summation of  $P_{Gi}$  must be increased simultaneous as the summation of  $P_{fi}$  is reduced to zero since the load flow equality constraints must be satisfied in this minimum control solvability problem. The positive initial value of  $P_{fi}$  shows the affect of load shedding as noted in (1) above. The initial value of  $P_{Gi}$  for the minimum control solvability problem are based on the VSSAD recommendation shown in Tables 4.9 – 4.11 and show the affects of generation shedding. The base  $P_{Gi}$  values, given in Tables 5.10 – 5.12, are the values before VSSAD recommended load and generation shedding given in Table 4.9 – 4.11;

4. the optimal value of  $P_{Gi}$  in Tables 5.10 – 5.12 for the three contingencies reflects the fact that the sum of  $P_{Gi}$  increased by approximately the same amount that the sum of  $P_{fi}$  approach zero. This accomplished the total elimination of the VSSAD recommended wheeling curtailment and the associated load and generation shedding that exists in the difference between the initial  $P_{Gi}$  and  $P_{fi}$  values and the optimal  $P_{Gi}$  and  $P_{fi}$  solution. This optimal solution has a load flow solution that did not exist if the contingency occurs with the base case  $P_{Gi}$  solution. Note that optimal  $P_{Gi}$  values do not return to precontingency or base case values even though their sum does with the added  $I^2R$  losses due to the contingency. The change from base case  $P_{Gi}$  value to optimal  $P_{Gi}$  values increase the network reactive losses that produced the clogging voltage instability and the lack of a load flow solution. Network reactive losses at the optimal solution is also larger than at the initial or VSSAD based solution as shown in Table 5.16. This is true because of the optimal control must reduce network reactive losses sufficiently on critical paths to correct the clogging voltage instability by the contingency. However, to add the load and generation recommended to be shed by VSSAD requires significant addition of reactive generation for all three clogging voltage instability cases. Note that “before” represents the load flow solution produced based on VSSAD recommendation and “after” represents the minimum control solvability solution. The optimal value of  $P_{Gi}$  also assures no thermal overload occur on any branch;
5. the optimal values of generator voltage setpoints, tap changer tap position and their changes hopefully help assure the voltage profile meets bus voltage limits and that the network reactive losses that produced the clogging voltage instability are reduced. These control

changes are shown in Table 5.13 – 5.15, and are arranged in the same way as Table 5.12 described above.

It should be noted that contingency cases 5 – 7 in Table 5.1 are shown in Tables 5.10 and 5.13, 5.11 and 5.14, 5.12 and 5.15 respectively. Note that in case 5 shown in Table 5.10, the optimal values of  $P_{fi}$  are not exactly zero but are approximately zero. The optimal values of  $P_{Gi}$  sum approximately to 9000 MW where as the sum of base case  $P_{Gi}^0$  values equals 9980 MW. This reduction in  $I^2R$  losses is unexpected when the double line outage is in optimization model and not in the base case. This agent reflects the large reduction in stress reflected in  $I^2R$  losses and reactive losses, that occurs through optimization which makes possible solvability for double contingencies that have no solution in the base case. The value of optimal  $P_{Gi}$  at generators 73 (NEAL 12G) and 76 (NEAL 34G) are reduced below the VSSAD recommended initial  $P_{Gi}$  values that are reduced from the base  $P_{Gi}$  values. This is true because the double line outage eliminates a major subtransmission path out of these generators. The optimal solution thus relieves the stress produced by this double line outage. The power eliminated from the initial  $P_{Gi}$  values as shown in the difference column is added to the other generators as can be seen in this column. Generation is restored on generators 121 and 130 to near their base case level and at 131, 118, and 101 at modestly ( $< 100$  MW) above their base case values. The optimal tap position value and changes have both large positive and negative values as shown in Table 5.13 that causes reactive flow direction and path changes in the network. The generator voltage setpoint values and changes are also shown. Almost all changes are positive as expected to compensate for the voltage stress of the contingency. The reactive generation change between the optimal and the VSSAD recommended initial value are shown in Table 5.13. The result suggest that despite almost 800 MW of additional load the increase reactive losses in the system were not large, which can be seen from Table 5.16.

For case 7, the results are identical to case 5 because it again is a double line outage affecting generators 73 and 76. The results are shown in Table 5.12 and 5.15.

Case 6 results are for a double generator outage. The double generator outage of bus 76 (NEAL 34G) and bus 131 (NEBCY 1G) required shedding of 1227.18 MW of load to compensate for the lost generation of 1227.18 MW of these two generators. The values of load shed at the buses given in Table 4.9 are the initial fictitious generation  $P_{fi}$  added on the fictitious generator buses connected to the actual load buses as shown in Table 5.11. The generation value after VSSAD are the initial values because VSSAD requires adjustment of the base case

generation levels at the actual generator buses shown in Table 5.11. The optimal values of  $P_{fi}$  are zero indicating the VSSAD recommended load and generation shedding has been eliminated in the optimal solution. The optimal value of  $P_{Gi}$  on these generators shows the greatest increase on generation occurs at bus 73 (NEAL 12G) and bus 108 (MTOW 3G). The added 1227 MW of generation, eliminates the load shedding and replaces the lost generator's generation. The added generation is less than 100 MW at all other generators in Table 5.11. The optimal tap changer tap position changes and generator voltage setpoint changes in Table 5.14 are chosen to cause voltage to be within bus voltage limits, reactive reserve basin reserves to lie within limits, and to reduce the increase in network reactive losses on critical paths accompanying adding 1227 MW back on the system. The total network reactive losses increase is shown in Table 5.16. The tap position changes show both large positive and negative values and the generator voltage setpoint changes are positive and between 1% and 2% to accomplish these objectives. The changes cause reactive flow direction and path changes to reduce the stress on the network.

## 6.0 Conclusion

A production grade version of our voltage stability security assessment program is complete and has been applied to systems of greater than 10,000 buses. The results

- 1) show that instability generally occurs whenever any agent experiences instability even though the instability has never been reported. This instability helps initiate the cascading instability of agents that is associated with voltage collapse
- 2) develop a method for finding the critical agent in a set of agents with nested reactive reserve basins. The exhaustion of reactive reserves on the critical agent causes voltage collapse and this has been verified for a P-V curve; a Q-V curve; and for single and double equipment outages
- 3) showed that the critical agents, each producing a different voltage collapse, contain generators that do not have large capacity, are often not relied on and even shielded from providing significant reactive supply; and do not have responsibility for voltage control of the major transmission hubs in the system. The voltage collapse problems are not solved directly via traditional methods of improving voltage control and seem to be ignored in conventional transmission/distribution system design
- 4) can find voltage collapse problems that were not previously known and numerous equipment outages not previously identified as causing voltage collapse

A on-line production grade diagnosis program is being developed that can

- (a) warn when single outages can produce a voltage collapse
- (b) automatically identify whether the voltage collapse is due to clogging or loss of control voltage instability
- (c) identify the critical agent and prescribe load and generation shedding or addition of reactive supply that is proportional to the severity of the voltage collapse;
- (d) provide operators alarms that provide warning and prescribe corrective action. This tool is being implemented in a control center

A minimum control solvability problem optimization is being developed that can be applied to large power system models and that can prescribe corrective controls with few control changes. This development is the most important because it actually has the effect of greatly increasing transmission capacity by adaptively changing generator excitation voltage setpoints, capacitor insertions, and underload tap changer tap positions for each specific contingency after it occurs and before it produces the blackout 2-5 minutes later. There would be a strong reluctance to posturing a system against one equipment outage and to then experience blackout for quite another equipment outage because the posturing for one equipment outage left it vulnerable to quite another contingency. A preventive control was formulated in [20] that would hopefully remove vulnerability of a system to all VSSAD predicted equipment outages. The preventive control's objective would adaptively adjust generator excitation setpoints, tap positions of underload tap changers, capacitor insertions, and active power dispatch to posture a system against a specific set of VSSAD identified contingencies without increasing vulnerability to any other contingencies. Although this formulation may be helpful in system commitment and system planning, it would likely greatly increase the ISO or TRANSCOs ancillary costs for use of control devices, and raise objections from operators because it would require such large control changes that they might expose the system to transient and dynamic stability problems and other unforeseen problems if used to dispatch a system. The operators view the operating point as something that provides security because it has been determined after thorough study of all consequences. The corrective control problem formulation is consistent with this reluctance to make control changes because it only makes these changes once the actual VSSAD predicted equipment outage has occurred and the blackout is inevitable without taking the corrective action. Implementing the corrective control would then have the huge benefit of correcting the impending blackout and any unforeseen stability problems can be dealt with as they develop or become possible once the developing blackout is corrected. The use of a minimum set of control changes to implement the

corrective control is obviously very important even if it is correcting an impending blackout and even if there would be a return to precontingency control setpoints as quickly as seem warranted. The combination of VSSAD and the minimum control solvability problem is intelligent because it learns, acquires knowledge, develops intelligence, is self diagnosing, self healing, self optimizing, self correcting, self stabilizing, and would be adaptive and implemented in a geographical and time based hierarchical structure [16].

The changes in state estimation, control, system planning, system commitment, and dispatch that would be required to fully realize the benefits of this corrective control is given in [1, 9, 20] and thus is not discussed in this paper.

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Figure 1

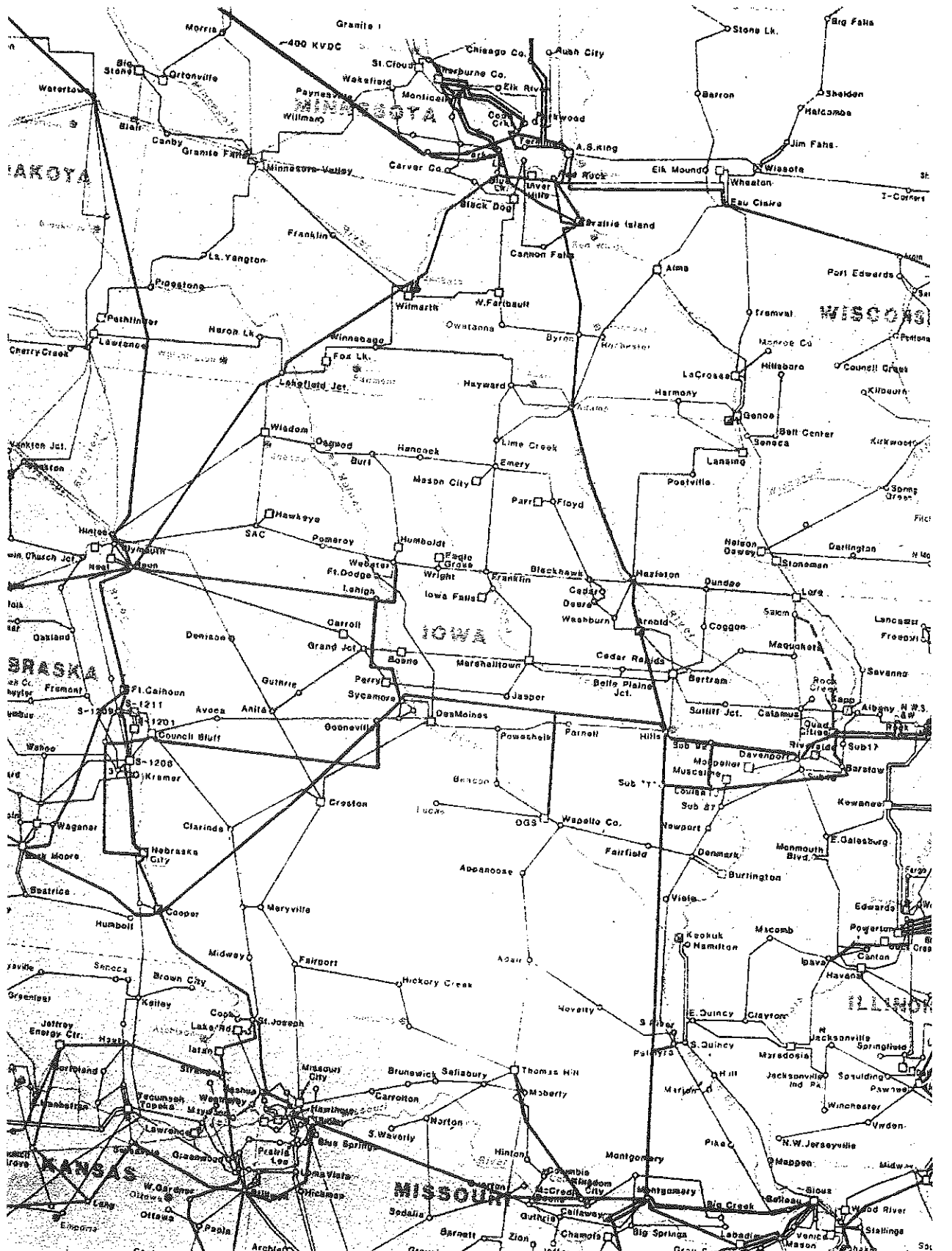


Figure 2

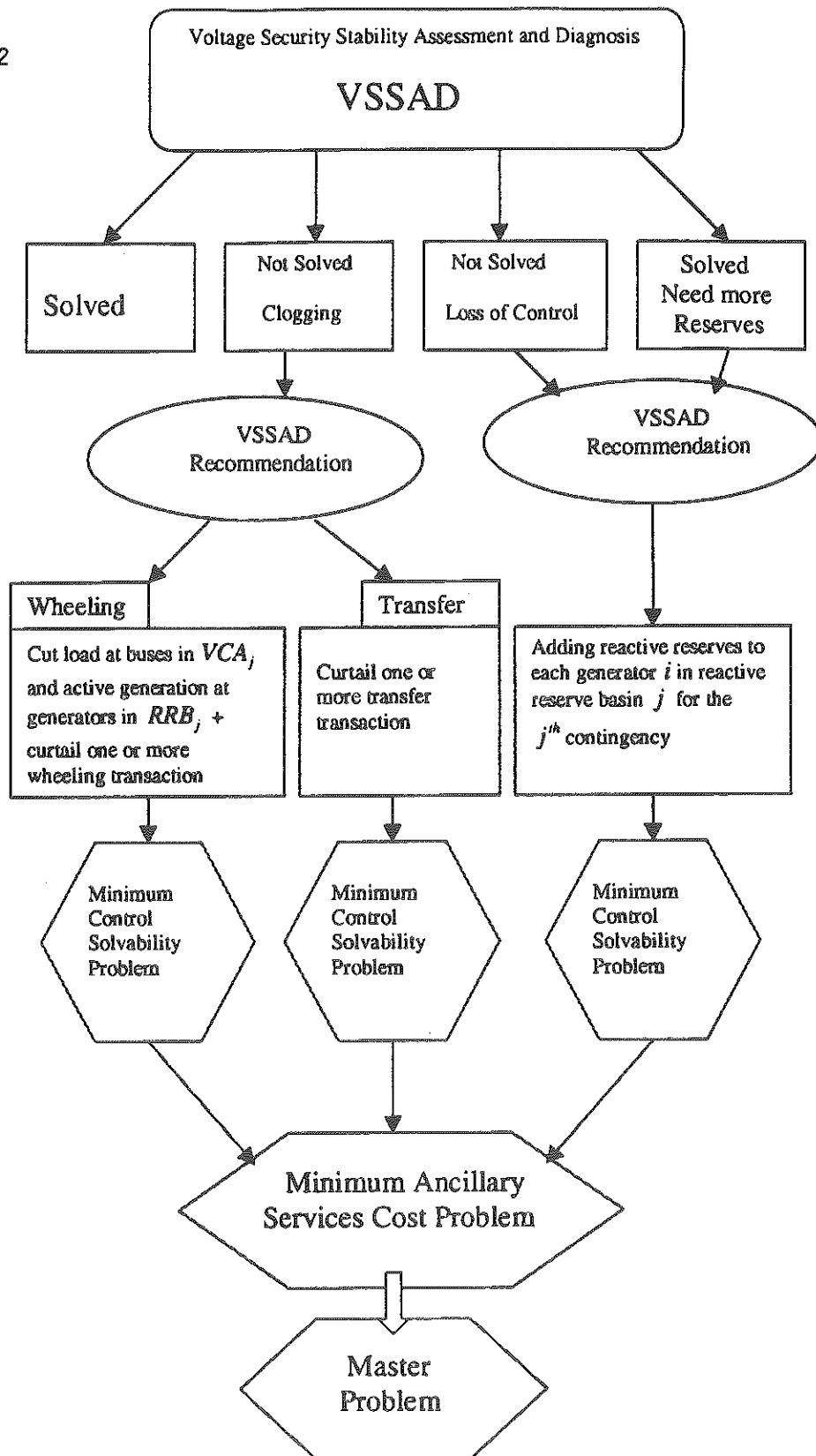


Table 4.1 Single Contingency Ranking for Voltage Collapse Region # 35.

|                            |                 |             |            |          |
|----------------------------|-----------------|-------------|------------|----------|
| 74 LEHIH 3 345 :           |                 |             |            |          |
| 55 PLYMH 5 161 :           |                 |             |            |          |
| 27 WILMRT3 345 :           |                 |             |            |          |
| Reac. Reser. Basin         | CAPACITY        | RESERVE     | VCA.       |          |
| 121 C.BL 3G 24             | 250.00          | 99.11       | 35         |          |
| 118 DPS 57G 14             | 100.00          | 40.25       | 37         |          |
| 73 NEAL12G 20              | 267.00          | 181.16      | 69         |          |
| 101 MTOW 3G 14             | 38.60           | 8.26        | 147        |          |
| TOTAL BASE RESERVE         |                 | 328.78      |            |          |
| CONTINGENCY RANKING        |                 |             |            |          |
| =====                      |                 |             |            |          |
| CONTINGENCY                | RRB%<br>of BASE | GEN<br>NAME | GEN<br>RES | VCA<br>% |
| Case:9 L. OUTAGE: 55 149   | 0.00%           | C.BL 3G 24  | 0.00       | 0.00%    |
|                            |                 | DPS 57G 14  | 0.00       | 0.00%    |
|                            |                 | NEAL12G 20  | 0.00       | 0.00%    |
|                            |                 | MTOW 3G 14  | 0.00       | 0.00%    |
| Case:31 L. OUTAGE: 161 162 | 0.30%           | C.BL 3G 24  | 0.00       | 0.00%    |
|                            |                 | DPS 57G 14  | 0.00       | 0.00%    |
|                            |                 | NEAL12G 20  | 1.00       | 0.55%    |
|                            |                 | MTOW 3G 14  | 0.00       | 0.00%    |
| Case:39 L. OUTAGE: 68 69   | 0.33%           | C.BL 3G 24  | 0.00       | 0.00%    |
|                            |                 | DPS 57G 14  | 0.00       | 0.00%    |
|                            |                 | NEAL12G 20  | 1.10       | 0.61%    |
|                            |                 | MTOW 3G 14  | 0.00       | 0.00%    |
| Case:15 L. OUTAGE: 71 85   | 1.61%           | C.BL 3G 24  | 0.00       | 0.00%    |
|                            |                 | DPS 57G 14  | 0.00       | 0.00%    |
|                            |                 | NEAL12G 20  | 5.30       | 2.93%    |
|                            |                 | MTOW 3G 14  | 0.00       | 0.00%    |
| Case:12 L. OUTAGE: 69 77   | 2.19%           | C.BL 3G 24  | 0.00       | 0.00%    |
|                            |                 | DPS 57G 14  | 0.00       | 0.00%    |
|                            |                 | NEAL12G 20  | 7.20       | 3.97%    |
|                            |                 | MTOW 3G 14  | 0.00       | 0.00%    |

Table 4.2. Double Contingency Ranking for Voltage Collapse Region # 35.

74 LEHIH 3 345 :  
 55 PLYMH 5 161 :  
 27 WILMRT3 345 :

| Reac. Reser. Basin        | CAPACITY        | RESERVE     | VCA        |          |
|---------------------------|-----------------|-------------|------------|----------|
| 121 C.BL 3G 24            | 250.00          | 99.11       | 35         |          |
| 118 DPS 57G 14            | 100.00          | 40.25       | 37         |          |
| 73 NEAL12G 20             | 267.00          | 181.16      | 69         |          |
| 101 MTOW 3G 14            | 38.60           | 8.26        | 147        |          |
| TOTAL BASE RESERVE        |                 | 328.78      |            |          |
| CONTINGENCY RANKING       |                 |             |            |          |
| =====                     |                 |             |            |          |
| CONTINGENCY               | RRB%<br>of BASE | GEN<br>NAME | GEN<br>RES | VCA<br>% |
| Case:4 G. OUTAGE: 6       | -57.85%         |             |            |          |
| G. OUTAGE: 131            |                 | C.BL 3G 24  | -127.3     | -128.44% |
|                           |                 | DPS 57G 14  | -38.4      | -95.40%  |
|                           |                 | NEAL12G 20  | 14.5       | 8.00%    |
|                           |                 | MTOW 3G 14  | -39.0      | 20.50%   |
| Case:27 L. OUTAGE: 68 69  | -39.78%         |             |            |          |
| L. OUTAGE: 69 77          |                 | C.BL 3G 24  | -19.3      | -19.47%  |
|                           |                 | DPS 57G 14  | -32.3      | -80.25%  |
|                           |                 | NEAL12G 20  | -44.0      | -24.29%  |
|                           |                 | MTOW 3G 14  | -35.2      | 26.91%   |
| Case:10 L. OUTAGE: 55 149 | -39.69%         |             |            |          |
| L. OUTAGE: 71 85          |                 | C.BL 3G 24  | -39.8      | -40.16%  |
|                           |                 | DPS 57G 14  | -53.9      | -133.91% |
|                           |                 | NEAL12G 20  | -10.1      | -5.58%   |
|                           |                 | MTOW 3G 14  | -26.7      | 20.46%   |
| Case:16 L. OUTAGE: 71 85  | -33.58%         |             |            |          |
| L. OUTAGE: 161 162        |                 | C.BL 3G 24  | -36.5      | -36.83%  |
|                           |                 | DPS 57G 14  | -51.7      | -128.45% |
|                           |                 | NEAL12G 20  | 3.6        | 1.99%    |
|                           |                 | MTOW 3G 14  | -25.8      | 23.37%   |
| Case:13 L. OUTAGE: 55 149 | -32.27%         |             |            |          |
| L. OUTAGE: 68 69          |                 | C.BL 3G 24  | -24.8      | -25.02%  |
|                           |                 | DPS 57G 14  | -34.5      | -85.71%  |
|                           |                 | NEAL12G 20  | -27.5      | -15.18%  |
|                           |                 | MTOW 3G 14  | -19.3      | 18.19%   |



Table 4.3. Single Outage that had affect on the largest number of agents

| Cont. Case | Single Contingency |     |             |     |             | # of VCR |
|------------|--------------------|-----|-------------|-----|-------------|----------|
| 9          | Line Outage:       | 55  | PLYMH 5 161 | 149 | RAUN 5 161  | 48       |
| 10         | Line Outage:       | 55  | PLYMH 5 161 | 162 | LEEDS 5 161 | 43       |
| 12         | Line Outage:       | 69  | HOPET 5 161 | 77  | WRIGT 5 161 | 10       |
| 15         | Line Outage:       | 71  | MONOA 5 161 | 85  | CARRLL5 161 | 48       |
| 31         | Line Outage:       | 161 | KELOG 5 161 | 162 | LEEDS 5 161 | 48       |
| 39         | Line Outage:       | 68  | HOPE 5 161  | 69  | HOPET 5 161 | 43       |
| 2          | Gen. Outage:       | 73  | NEAL12G 20  |     |             | 1        |

Table 4.4. Double Outage that had affect on the most agents

| Cont. Case | Double Contingency |     |             |     |             | # of VCR |
|------------|--------------------|-----|-------------|-----|-------------|----------|
| 8          | Gen. Outage:       | 6   | 6R1G 22     |     |             | 19       |
|            | Gen. Outage:       | 73  | NEAL12G 20  |     |             |          |
| 14         | Gen. Outage:       | 73  | NEAL12G 20  |     |             | 3        |
|            | Gen. Outage:       | 130 | FT.CL1G 22  |     |             |          |
| 15         | Gen. Outage:       | 73  | NEAL12G 20  |     |             | 2        |
|            | Gen. Outage:       | 121 | C.BL 3G 24  |     |             |          |
| 18         | Gen. Outage:       | 73  | NEAL12G 20  |     |             | 1        |
|            | Gen. Outage:       | 99  | PRARK4G 18  |     |             |          |
| 21         | Gen. Outage:       | 130 | FT.CL1G 22  |     |             | 1        |
|            | Gen. Outage:       | 131 | NEBCY1G 18  |     |             |          |
| 24         | Gen. Outage:       | 121 | C.BL 1G 24  |     |             | 31       |
|            | Gen. Outage:       | 131 | NEBCY1G 18  |     |             |          |
| 57         | Gen. Outage:       | 76  | NEAL34G 24  |     |             | 6        |
|            | Line Outage:       | 55  | PLYMH 5 161 | 149 | RAUN 5 161  |          |
| 59         | Gen. Outage:       | 76  | NEAL34G 24  |     |             | 3        |
|            | Line Outage:       | 161 | KELOG 5 161 | 162 | LEEDS 5 161 |          |
| 61         | Gen. Outage:       | 76  | NEAL34G 24  |     |             | 3        |
|            | Line Outage:       | 68  | HOPE 5 161  | 69  | HOPET 5 161 |          |
| 71         | Gen. Outage:       | 99  | PRARK4G 18  |     |             | 47       |
|            | Line Outage:       | 55  | PLYMH 5 161 | 149 | RAUN 5 161  |          |
| 72         | Gen. Outage:       | 99  | PRARK4G 18  |     |             | 38       |
|            | Line Outage:       | 71  | MONOA 5 161 | 85  | CARRLL5 161 |          |
| 73         | Gen. Outage:       | 99  | PRARK4G 18  |     |             | 32       |
|            | Line Outage:       | 161 | KELOG 5 161 | 162 | LEEDS 5 161 |          |
| 75         | Gen. Outage:       | 99  | PRARK4G 18  |     |             | 4        |
|            | Line Outage:       | 68  | HOPE 5 161  | 69  | HOPET 5 161 |          |
| 95         | Line Outage:       | 55  | PLYMH 5 161 | 162 | LEEDS 5 161 | 40       |
|            | Line Outage:       | 85  | CARRLL5 161 | 86  | GR JT 5 161 |          |
| 97         | Line Outage:       | 68  | HOPE 5 161  | 69  | HOPET 5 161 | 6        |
|            | Line Outage:       | 85  | CARRLL5 161 | 86  | GR JT 5 161 |          |

Table 4.5. Double Outage with negative reserves when the gen. limits are ignored

| Cont. Case | Double Contingency with Ignoring Reactive Limits |             |     |              | # of VCR |
|------------|--------------------------------------------------|-------------|-----|--------------|----------|
| 1          | Gen. Outage: 6                                   | 6R1G 22     |     |              | 9        |
|            | Gen. Outage: 130                                 | FT.CL1G 22  |     |              |          |
| 2          | Gen. Outage: 6                                   | 6R1G 22     |     |              | 29       |
|            | Gen. Outage: 121                                 | C.BL 3G 24  |     |              |          |
| 4          | Gen. Outage: 6                                   | 6R1G 22     |     |              | 38       |
|            | Gen. Outage: 131                                 | NEBCY1G 18  |     |              |          |
| 10         | Line Outage: 55                                  | PLYMH 5 161 | 149 | RAUN 5 161   | 26       |
|            | Line Outage: 71                                  | MONOA 5 161 | 85  | CARRLL5 161  |          |
| 13         | Line Outage: 55                                  | PLYMH 5 161 | 149 | RAUN 5 161   | 13       |
|            | Line Outage: 68                                  | HOPE 5 161  | 69  | HOPET 5 161  |          |
| 14         | Line Outage: 55                                  | PLYMH 5 161 | 149 | RAUN 5 161   | 1        |
|            | Line Outage: 69                                  | HOPET 5 161 | 77  | WRIGHT 5 161 |          |
| 16         | Line Outage: 71                                  | MONOA 5 161 | 85  | CARRLL5 161  | 13       |
|            | Line Outage: 161                                 | KELOG 5 161 | 162 | LEEDS 5 161  |          |
| 22         | Line Outage: 161                                 | KELOG 5 161 | 162 | LEEDS 5 161  | 2        |
|            | Line Outage: 68                                  | HOPE 5 161  | 69  | HOPET 5 161  |          |
| 27         | Line Outage: 68                                  | HOPE 5 161  | 69  | HOPET 5 161  | 28       |
|            | Line Outage: 69                                  | HOPET 5 161 | 77  | WRIGHT 5 161 |          |

Table 4.6. Voltage Stability Assessment Results for Voltage Collapse Regions that are Vulnerable to Loss of Control Voltage Instability

| VCR # | Voltage Control Area                                                                    | Reactive Reserve Basin                                                                             | B. Case Reserves | RR of B. Case      | Cont. Case |
|-------|-----------------------------------------------------------------------------------------|----------------------------------------------------------------------------------------------------|------------------|--------------------|------------|
| 3     | 125 PALM710 345<br>156 E SIDE8 69                                                       | 73 NEAL12G 20                                                                                      | 181.16           | -6.18%             | 14         |
| 5     | 161 KELOG 5 161<br>45 TRIBJI5 161<br>23 HRN K 5 161                                     | 73 NEAL12G 20<br>121 C.BL 3G 24                                                                    | 280.27           | -13.74%            | 22         |
| 35    | 74 LEHIH 3 345<br>55 PLYMH 5 161<br>27 WILMRT3 345                                      | 73 NEAL12G 20<br>101 MTOW 3G 14<br>118 DPS 57G 14<br>121 C.BL 3G 24                                | 328.78           | -39.78%<br>-32.27% | 27<br>13   |
| 34    | 77 WRIGT 5 161<br>39 HAZLON3 345<br>37 ADAM 3 345                                       | 73 NEAL12G 20<br>101 MTOW 3G 14<br>118 DPS 57G 14<br>121 C.BL 3G 24<br>130 FT.CL1G 22              | 493.41           | -25.03%<br>-20.25% | 10<br>16   |
| 22    | 119 SYCAOR3 345<br>106 MONRE 5 161<br>52 D.MON 5 161<br>4 BOONIL3 345<br>86 GR JT 5 161 | 6 6R1G 22<br>73 NEAL12G 20<br>101 MTOW 3G 14<br>118 DPS 57G 14<br>121 C.BL 3G 24<br>130 FT.CL1G 22 | 712.60           | -21.37%<br>-11.65% | 2<br>1     |
| 23    | 110 CBLUFS5 161                                                                         | 6 6R1G 22<br>73 NEAL12G 20<br>114 C.BL12G 14<br>121 C.BL 3G 24<br>130 FT.CL1G 22<br>131 NEBcy1G 18 | 900.29           | -26.88%            | 4          |

Table 4.7. Additional Reactive Supply Needed to Cure Loss of Control Voltage Instability

| Gen.<br>B.# | Double Contingency Case # |       |        |        |        |        |        |        |        |
|-------------|---------------------------|-------|--------|--------|--------|--------|--------|--------|--------|
|             | 14                        | 22    | 13     | 27     | 16     | 10     | 1      | 2      | 4      |
| 73          | 11.20                     | 15.90 | 27.50  | 44.00  |        | 10.10  |        |        |        |
| 121         |                           | 22.60 | 24.80  | 19.30  | 36.50  | 39.80  | 53.00  |        | 127.30 |
| 101         |                           |       | 19.30  | 35.20  | 25.80  | 26.70  | 39.10  | 43.20  | 39.00  |
| 118         |                           |       | 34.50  | 23.30  | 51.70  | 53.90  | 22.90  | 43.10  | 38.40  |
| 114         |                           |       |        |        | 40.40  | 41.30  | 42.60  | 73.60  | 59.70  |
| 99          |                           |       |        |        |        |        | 20.30  | 23.40  | 15.80  |
| 130         |                           |       |        |        |        |        |        | 77.10  | 69.50  |
| Tot.        | 11.20                     | 38.50 | 106.10 | 130.80 | 154.40 | 171.80 | 177.90 | 260.40 | 349.70 |
| VCR         | 3                         | 5     | 35     | 35     | 34     | 34     | 22     | 22     | 23     |
| RRB         | 73                        | 73    | 73     | 73     | 73     | 73     | 73     | 73     | 73     |
|             |                           | 121   | 121    | 121    | 121    | 121    | 121    | 121*   | 121    |
|             |                           |       | 101    | 101    | 101    | 101    | 101    | 101    | 114    |
|             |                           |       | 118    | 118    | 118    | 118    | 118    | 118    | 131*   |
|             |                           |       |        |        | 130    | 130    | 130*   | 130    | 130    |
|             |                           |       |        |        |        |        | 6*     | 6*     | 6*     |

\* means the generator bus # is part of the double contingency.

Table 4.8. Unsolved Double Contingency Cases

| conting. | Double Contingency |     |         |     |     |         |     |  |
|----------|--------------------|-----|---------|-----|-----|---------|-----|--|
| Case: 5  | Gen. Outage:       | 73  | NEAL12G | 20  |     |         |     |  |
|          | Gen. Outage:       | 76  | NEAL34G | 24  |     |         |     |  |
| Case: 8  | Gen. Outage:       | 76  | NEAL34G | 24  |     |         |     |  |
|          | Gen. Outage:       | 131 | NEBCY1G | 18  |     |         |     |  |
| Case: 11 | Line Outage:       | 55  | PLYMH 5 | 161 | 149 | RAUN 5  | 161 |  |
|          | Line Outage:       | 161 | KELOG 5 | 161 | 162 | LEEDS 5 | 161 |  |
| Case: 12 | Line Outage:       | 55  | PLYMH 5 | 161 | 149 | RAUN 5  | 161 |  |
|          | Line Outage:       | 55  | PLYMH 5 | 161 | 162 | LEEDS 5 | 161 |  |
| Case: 20 | Line Outage:       | 71  | MONOA 5 | 161 | 85  | CARRLL5 | 161 |  |
|          | Line Outage:       | 85  | CARRLL5 | 161 | 86  | GR JT 5 | 161 |  |
| Case: 21 | Line Outage:       | 161 | KELOG 5 | 161 | 162 | LEEDS 5 | 161 |  |
|          | Line Outage:       | 55  | PLYMH 5 | 161 | 162 | LEEDS 5 | 161 |  |

Table 4.9. Load Shed for Case # 8

| Case: 8   |          | Gen. Outage: 76 NEAL34G 24  |                |
|-----------|----------|-----------------------------|----------------|
|           |          | Gen. Outage: 131 NEBCY1G 18 |                |
| Load Bus# | Bus Name |                             | Load Reduction |
| 20        | HINTON8  | 69                          | -40.90         |
| 40        | BLKHK 5  | 161                         | -52.88         |
| 87        | GUTHIE7  | 115                         | -16.91         |
| 103       | DAVNRT5  | 161                         | -322.00        |
| 111       | AVOC 5   | 161                         | -65.41         |
| 113       | S1211 5  | 161                         | -32.70         |
| 139       | S706 8   | 69                          | -10.10         |
| 142       | CLRND8   | 69                          | -27.09         |
| 157       | PLYMTH8  | 69                          | -32.00         |
| 160       | SC WST8  | 69                          | -14.40         |
| 30        | HAYWD 5  | 161                         | -190.20        |
| 38        | DUNDE 5  | 161                         | -14.76         |
| 46        | DENIN 5  | 161                         | -65.31         |
| 59        | EAGL 4   | 230                         | -104.43        |
| 91        | CDRPS 5  | 161                         | -51.25         |
| 94        | HILL 5   | 161                         | -162.00        |
| 105       | DUNDE 7  | 115                         | -24.84         |
| Total     | =        |                             | -1227.18       |

Table 4.10. Load and Generation Shedding for Case # 11

| Case: 11  |          | Line Outage: 55 PLYMH 5 161  |  | 149 RAUN 5 161  |
|-----------|----------|------------------------------|--|-----------------|
|           |          | Line Outage: 161 KELOG 5 161 |  | 162 LEEDS 5 161 |
| Load Bus# | Bus Name |                              |  | Load Reduction  |
| 27        | WILMRT3  | 345                          |  | -324.00         |
| 151       | INTRCG5  | 161                          |  | -24.00          |
| 80        | POME0Y5  | 161                          |  | -15.76          |
| 161       | KELOG 5  | 161                          |  | -42.00          |
| 45        | TRIBJI5  | 161                          |  | -20.00          |
| 162       | LEEDS 5  | 161                          |  | -30.00          |
| 54        | WISDM 5  | 161                          |  | -94.04          |
| 57        | SAC 5    | 161                          |  | -48.48          |
| 56        | OSGOD 5  | 161                          |  | -25.29          |
| 29        | WINBGO5  | 161                          |  | -28.31          |
| 28        | FOX k5   | 161                          |  | -38.47          |
| 18        | ADAM 5   | 161                          |  | -40.40          |
| 15        | FTRAD 4  | 230                          |  | -160.00         |
| Total     | =        |                              |  | -890.75         |
| Gen. Bus# | Bus Name |                              |  | Gen. Reduction  |
| 73        | NEAL12G  | 20                           |  | -235.59         |
| 76        | NEAL34G  | 24                           |  | -133.98         |
| 101       | MTOW 3G  | 14                           |  | -81.00          |
| 118       | DPS 57G  | 14                           |  | -81.00          |
| 121       | C.BL 3G  | 24                           |  | -235.59         |
| 130       | FT.CL1G  | 22                           |  | -123.59         |
| Total     | =        |                              |  | -890.75         |

Table 4.11. Load and Generation Shedding for Case # 12

| Case: 12                    |          |                 |                |
|-----------------------------|----------|-----------------|----------------|
| Line Outage: 55 PLYMH 5 161 |          | 149 RAUN 5 161  |                |
| Line Outage: 55 PLYMH 5 161 |          | 162 LEEDS 5 161 |                |
| Load Bus#                   | Bus Name |                 | Load Reduction |
| 27                          | WILMRT3  | 345             | -324.00        |
| 151                         | INTRCG5  | 161             | -24.00         |
| 80                          | POMEYOY5 | 161             | -15.76         |
| 162                         | LEEDS 5  | 161             | -30.00         |
| 54                          | WISDM 5  | 161             | -94.04         |
| 57                          | SAC 5    | 161             | -48.48         |
| 56                          | OSGOD 5  | 161             | -25.29         |
| 29                          | WINBGO5  | 161             | -28.31         |
| 28                          | FOX k5   | 161             | -38.47         |
| 18                          | ADAM 5   | 161             | -40.40         |
| 15                          | FTRAD 4  | 230             | -160.00        |
| Total                       | =        |                 | -828.75        |
| Gen. Bus#                   | Bus Name |                 | Gen. Reduction |
| 73                          | NEAL12G  | 20              | -204.59        |
| 76                          | NEAL34G  | 24              | -133.98        |
| 101                         | MTOW 3G  | 14              | -81.00         |
| 118                         | DPS 57G  | 14              | -81.00         |
| 121                         | C.BL 3G  | 24              | -204.59        |
| 130                         | FT.CL1G  | 22              | -123.59        |
| Total                       | =        |                 | -828.75        |

Table 5.1. Selected Double Contingency Cases for Solvability problems.

| Conting. | Unsolved Double Contingency |     |         |     |     |              |
|----------|-----------------------------|-----|---------|-----|-----|--------------|
| Case: 1  | Gen. Outage:                | 6   | 6R1G    | 22  |     |              |
|          | Gen. Outage:                | 121 | C.BL 3G | 24  |     |              |
| Case: 2  | Gen. Outage:                | 6   | 6R1G    | 22  |     |              |
|          | Gen. Outage:                | 131 | NEBCY1G | 18  |     |              |
| Case: 3  | Line Outage:                | 68  | HOPE 5  | 161 | 69  | HOPET 5 161  |
|          | Line Outage:                | 69  | HOPET 5 | 161 | 77  | WRIGHT 5 161 |
| Case: 4  | Line Outage:                | 55  | PLYMH 5 | 161 | 149 | RAUN 5 161   |
|          | Line Outage:                | 71  | MONOA 5 | 161 | 85  | CARRLL5 161  |
| Case: 5  | Line Outage:                | 55  | PLYMH 5 | 161 | 149 | RAUN 5 161   |
|          | Line Outage:                | 161 | KELOG 5 | 161 | 162 | LEEDS 5 161  |
| Case: 6  | Gen. Outage:                | 76  | NEAL34G | 24  |     |              |
|          | Gen. Outage:                | 131 | NEBCY1G | 18  |     |              |
| Case: 7  | Line Outage:                | 55  | PLYMH 5 | 161 | 149 | RAUN 5 161   |
|          | Line Outage:                | 55  | PLYMH 5 | 161 | 162 | LEEDS 5 161  |

Table 5.2. Reactive Generation Supply by Fictitious Generators for Case# 1.

Case No. 1 Gen. Outage: 6 6R1G 22  
 Gen. Outage: 121 C.BL 3G 24

primal objective = .4507062312D-17  
 dual objective = -.2377240562D-04  
 max. power mismatch = .6722707628D-04  
 max. dual mismatch = .9864576821D-06

|    | Bus#      | Optimal<br>$Q_g$ | Minimum<br>$Q_g$ | Maximum<br>$Q_g$ | Initial<br>$Q_g$ | Difference |
|----|-----------|------------------|------------------|------------------|------------------|------------|
| 1  | 73        | 149.0838         | -72.0000         | 267.0000         | 85.8400          | 63.2438    |
| 2  | 76        | 251.3038         | -170.0000        | 605.0000         | 136.3100         | 114.9938   |
| 3  | 99        | 30.1392          | -60.6000         | 75.6000          | 5.2100           | 24.9292    |
| 4  | 101       | 19.2449          | -24.4000         | 38.6000          | 30.3400          | -11.0951   |
| 5  | 108       | 448.4322         | 9999.0000        | 9999.0000        | 155.8200         | 292.6122   |
| 6  | 114       | -3.2716          | -25.0000         | 33.0000          | 22.2900          | -25.5616   |
| 7  | 118       | 66.4634          | -44.0000         | 100.0000         | 59.7500          | 6.7134     |
| 8  | 125       | -363.2716        | 1099.0000        | 9900.0000        | -22.9400         | -340.3316  |
| 9  | 130       | 178.5795         | -144.0000        | 288.0000         | 123.3700         | 55.2095    |
| 10 | 131       | 126.5420         | -265.0000        | 320.0000         | 94.5100          | 32.0320    |
| f1 | 163 (99)  | .0000            | -30.0000         | 30.0000          | 25.0000          | -25.0000   |
| f2 | 164 (101) | .0000            | -60.0000         | 60.0000          | 45.0000          | -45.0000   |
| f3 | 165 (114) | .0000            | -80.0000         | 80.0000          | 75.0000          | -75.0000   |
| f4 | 166 (118) | .0000            | -60.0000         | 60.0000          | 45.0000          | -45.0000   |
| f5 | 167 (130) | .0000            | -90.0000         | 90.0000          | 85.0000          | -85.0000   |

Table 5.3. Reactive Generation Supply by Fictitious Generators for Case# 2.

Case No. 2 Gen. Outage: 6 6R1G 22  
 Gen. Outage: 131 NEBCY1G 18

primal objective = .2931041047D-16  
 dual objective = -.3543313451D-04  
 max. power mismatch = .1349672117D-04  
 max. dual mismatch = .2565564438D-05

|    | Bus#      | Optimal<br>$Q_g$ | Minimum<br>$Q_g$ | Maximum<br>$Q_g$ | Initial<br>$Q_g$ | Difference |
|----|-----------|------------------|------------------|------------------|------------------|------------|
| 1  | 73        | 157.3901         | -72.0000         | 267.0000         | 85.8400          | 71.5501    |
| 2  | 76        | 186.1923         | -170.0000        | 605.0000         | 136.3100         | 49.8823    |
| 3  | 99        | 42.4831          | -60.6000         | 75.6000          | 5.2100           | 37.2731    |
| 4  | 101       | 5.9973           | -24.4000         | 38.6000          | 30.3400          | -24.3427   |
| 5  | 108       | 439.3431         | 9999.0000        | 9999.0000        | 155.8200         | 283.5231   |
| 6  | 114       | 14.0119          | -25.0000         | 33.0000          | 22.2900          | -8.2781    |
| 7  | 118       | 82.3730          | -44.0000         | 100.0000         | 59.7500          | 22.6230    |
| 8  | 121       | 125.9771         | -120.0000        | 250.0000         | 150.8900         | -24.9129   |
| 9  | 125       | -348.4704        | 1099.0000        | 9900.0000        | -22.9400         | -325.5304  |
| 10 | 130       | 130.3286         | -144.0000        | 288.0000         | 123.3700         | 6.9586     |
| f1 | 163 (101) | .0000            | -60.0000         | 60.0000          | 50.0000          | -50.0000   |
| f2 | 164 (114) | .0000            | -80.0000         | 80.0000          | 65.0000          | -65.0000   |
| f3 | 165 (118) | .0000            | -60.0000         | 60.0000          | 45.0000          | -45.0000   |
| f4 | 166 (121) | .0000            | -140.0000        | 140.0000         | 130.0000         | -130.0000  |
| f5 | 167 (130) | .0000            | -90.0000         | 90.0000          | 80.0000          | -80.0000   |



Table 5.4. Reactive Generation Supply by Fictitious Generators for Case# 3.

Case No. 3    Line Outage:    68    HOPE 5    161                      69    HOPET 5    161  
                                          Line Outage:    69    HOPET 5    161                      77    WRIGT 5    161

primal objective                      =        .0000000000D+00  
dual objective                        =        -.1619183098D-06  
max. power mismatch                =        .1704386895D-03  
max. dual mismatch                 =        .4216405042D-07

|    | Bus#      | Optimal<br>$Q_g$ | Minimum<br>$Q_g$ | Maximum<br>$Q_g$ | Initial<br>$Q_g$ | Difference |
|----|-----------|------------------|------------------|------------------|------------------|------------|
| 1  | 6         | 288.7779         | -200.0000        | 400.0000         | 180.8100         | 107.9679   |
| 2  | 73        | 21.5504          | -72.0000         | 267.0000         | 85.8400          | -64.2896   |
| 3  | 76        | 420.8147         | -170.0000        | 605.0000         | 136.3100         | 284.5047   |
| 4  | 99        | -53.7921         | -60.6000         | 75.6000          | 5.2100           | -59.0021   |
| 5  | 101       | 9.4768           | -24.4000         | 38.6000          | 30.3400          | -20.8632   |
| 6  | 108       | 94.9468          | 9999.0000        | 9999.0000        | 155.8200         | -60.8732   |
| 7  | 114       | 10.1152          | -25.0000         | 33.0000          | 22.2900          | -12.1748   |
| 8  | 118       | 86.9789          | -44.0000         | 100.0000         | 59.7500          | 27.2289    |
| 9  | 121       | 97.4573          | -120.0000        | 250.0000         | 150.8900         | -53.4327   |
| 10 | 125       | -453.2626        | 1099.0000        | 9900.0000        | -22.9400         | -430.3226  |
| 11 | 130       | 127.1681         | -144.0000        | 288.0000         | 123.3700         | 3.7981     |
| 12 | 131       | -150.5728        | -265.0000        | 320.0000         | 94.5100          | -245.0828  |
| f1 | 163 (73)  | .0000            | -60.0000         | 60.0000          | 50.0000          | -50.0000   |
| f2 | 164 (76)  | .0000            | -20.0000         | 20.0000          | 10.0000          | -10.0000   |
| f3 | 165 (101) | .0000            | -60.0000         | 60.0000          | 45.0000          | -45.0000   |
| f4 | 166 (118) | .0000            | -60.0000         | 60.0000          | 45.0000          | -45.0000   |
| f5 | 167 (121) | .0000            | -60.0000         | 60.0000          | 45.0000          | -45.0000   |

Table 5.5. Reactive Generation Supply by Fictitious Generators for Case# 4.

Case No. 4 Line Outage: 55 PLYMH 5 161 149 RAUN 5 161  
 Line Outage: 71 MONOA 5 161 85 CARRLL5 161

primal objective = .1858329935D-12  
 dual objective = -.5247823050D-04  
 max. power mismatch = .4368341865D-04  
 max. dual mismatch = .5969542581D-06

|    | Bus#      | Optimal<br>$Q_g$ | Minimum<br>$Q_g$ | Maximum<br>$Q_g$ | Initial<br>$Q_g$ | Difference |
|----|-----------|------------------|------------------|------------------|------------------|------------|
| 1  | 6         | 305.3386         | -200.0000        | 400.0000         | 180.8100         | 124.5286   |
| 2  | 73        | 117.2346         | -72.0000         | 267.0000         | 85.8400          | 31.3946    |
| 3  | 76        | 236.1612         | -170.0000        | 605.0000         | 136.3100         | 99.8512    |
| 4  | 99        | 42.7035          | -60.6000         | 75.6000          | 5.2100           | 37.4935    |
| 5  | 101       | 38.1811          | -24.4000         | 38.6000          | 30.3400          | 7.8411     |
| 6  | 108       | -86.3633         | 9999.0000        | 9999.0000        | 155.8200         | -242.1833  |
| 7  | 114       | -.8450           | -25.0000         | 33.0000          | 22.2900          | -23.1350   |
| 8  | 118       | 97.4257          | -44.0000         | 100.0000         | 59.7500          | 37.6757    |
| 9  | 121       | 129.8089         | -120.0000        | 250.0000         | 150.8900         | -21.0811   |
| 10 | 125       | -406.9398        | 1099.0000        | 9900.0000        | -22.9400         | -383.9998  |
| 11 | 130       | 131.3392         | -144.0000        | 288.0000         | 123.3700         | 7.9692     |
| 12 | 131       | 153.8545         | -265.0000        | 320.0000         | 94.5100          | 59.3445    |
| f1 | 163 (73)  | .0000            | -60.0000         | 60.0000          | 45.0000          | -45.0000   |
| f2 | 164 (101) | .0000            | -40.0000         | 40.0000          | 30.0000          | -30.0000   |
| f3 | 165 (114) | .0000            | -60.0000         | 60.0000          | 45.0000          | -45.0000   |
| f4 | 166 (118) | .0000            | -70.0000         | 70.0000          | 60.0000          | -60.0000   |
| f5 | 167 (121) | .0000            | -60.0000         | 60.0000          | 45.0000          | -45.0000   |

Table 5.6. Voltage Set Point, Shunt Cap., and Transformer Tap Control Changes.

Case No. 1 Gen. Outage: 6 6R1G 22  
 Gen. Outage: 121 C.BL 3G 24

|   | Bus | Optimal<br>$V_g$ | Minimum<br>$V_g$ | Maximum<br>$V_g$ | Initial<br>$V_g$ | Difference |
|---|-----|------------------|------------------|------------------|------------------|------------|
| 1 | 73  | 1.01336          | .95000           | 1.05000          | 1.00000          | .01300     |
| 2 | 108 | 1.02826          | .95000           | 1.05000          | 1.00000          | .02800     |
| 3 | 118 | 1.01112          | .95000           | 1.05000          | 1.00000          | .01100     |
| 4 | 125 | 1.04849          | .95000           | 1.05000          | 1.02000          | .02800     |
| 5 | 130 | .99811           | .95000           | 1.05000          | 1.03000          | -.03100    |

|    | Bus | Optimal<br>$S_i$ | Minimum<br>$S_i$ | Maximum<br>$S_i$ |
|----|-----|------------------|------------------|------------------|
| 1  | 1   | .50              | .00              | 1.00             |
| 2  | 5   | .50              | .00              | 1.00             |
| 3  | 26  | .25              | .00              | 1.00             |
| 4  | 52  | .75              | .00              | 1.00             |
| 5  | 70  | .25              | .00              | 1.00             |
| 6  | 75  | .50              | .00              | 1.00             |
| 7  | 95  | .75              | .00              | 1.00             |
| 8  | 96  | .50              | .00              | 1.00             |
| 9  | 110 | .50              | .00              | 1.00             |
| 10 | 112 | .50              | .00              | 1.00             |

|    | From<br>Bus | To<br>Bus | Optimal<br>$t_{ij}$ | Minimum<br>$t_{ij}$ | Maximum<br>$t_{ij}$ | Initial<br>$t_{ij}$ | Difference |
|----|-------------|-----------|---------------------|---------------------|---------------------|---------------------|------------|
| 1  | 1           | 6         | 1.00993             | .90000              | 1.10000             | 1.05190             | -.04197    |
| 2  | 12          | 2         | .99025              | .90000              | 1.10000             | 1.02520             | -.03495    |
| 3  | 18          | 37        | 1.03599             | .90000              | 1.13000             | 1.11930             | -.08331    |
| 4  | 60          | 61        | .99013              | .90000              | 1.10000             | 1.02520             | -.03507    |
| 5  | 66          | 11        | .96091              | .90000              | 1.10000             | 1.00000             | -.03909    |
| 6  | 93          | 42        | 1.05567             | .90000              | 1.10000             | 1.02480             | .03087     |
| 7  | 95          | 91        | .96902              | .90000              | 1.10000             | 1.02000             | -.05098    |
| 8  | 95          | 99        | .99458              | .90000              | 1.10000             | 1.02960             | -.03502    |
| 9  | 98          | 93        | .98522              | .90000              | 1.10000             | 1.02520             | -.03998    |
| 10 | 110         | 112       | 1.03087             | .90000              | 1.10000             | 1.00000             | .03087     |
| 11 | 112         | 121       | 1.00597             | .90000              | 1.10000             | 1.04990             | -.04393    |
| 12 | 142         | 51        | 1.02225             | .90000              | 1.10000             | 1.07000             | -.04775    |
| 13 | 157         | 55        | 1.03651             | .90000              | 1.10000             | 1.00000             | .03651     |

Table 5.7. Voltage Set Point, and Shunt Cap. Control Changes.

Case No. 2 Gen. Outage: 6 6R1G 22  
 Gen. Outage: 131 NEBCY1G 18

|    | Bus | Optimal<br>$V_g$ | Minimum<br>$V_g$ | Maximum<br>$V_g$ | Initial<br>$V_g$ | Difference |
|----|-----|------------------|------------------|------------------|------------------|------------|
| 1  | 73  | 1.01161          | .95000           | 1.05000          | 1.00000          | .01100     |
| 2  | 76  | .98556           | .95000           | 1.05000          | 1.00000          | -.01400    |
| 3  | 99  | .98973           | .95000           | 1.05000          | 1.00000          | -.01000    |
| 4  | 101 | .98444           | .95000           | 1.05000          | 1.00000          | -.01500    |
| 5  | 108 | .96213           | .95000           | 1.05000          | 1.00000          | -.03700    |
| 6  | 114 | .97757           | .95000           | 1.05000          | 1.00000          | -.02200    |
| 7  | 118 | 1.02792          | .95000           | 1.05000          | 1.00000          | .02700     |
| 8  | 121 | .98792           | .95000           | 1.05000          | 1.00000          | -.01200    |
| 9  | 125 | 1.04683          | .95000           | 1.05000          | 1.02000          | .02600     |
| 10 | 130 | 1.00621          | .95000           | 1.05000          | 1.03000          | -.02300    |

|   | Bus | Optimal<br>$S_i$ | Minimum<br>$S_i$ | Maximum<br>$S_i$ |
|---|-----|------------------|------------------|------------------|
| 1 | 1   | 1.00             | .00              | 1.00             |
| 2 | 5   | .75              | .00              | 1.00             |
| 3 | 52  | 1.00             | .00              | 1.00             |
| 4 | 70  | .75              | .00              | 1.00             |
| 5 | 75  | .50              | .00              | 1.00             |
| 6 | 95  | .75              | .00              | 1.00             |
| 7 | 96  | .75              | .00              | 1.00             |
| 8 | 110 | .75              | .00              | 1.00             |
| 9 | 112 | .50              | .00              | 1.00             |

Table 5.8. Voltage Set Point, Shunt Cap., and Transformer Tap Control Changes.

| Case No. 3 | Line Outage: 68 HOPE 5 161  |                  |                  | 69 HOPET 5 161   |                  |            |
|------------|-----------------------------|------------------|------------------|------------------|------------------|------------|
|            | Line Outage: 69 HOPET 5 161 |                  |                  | 77 WRIGT 5 161   |                  |            |
|            | Bus                         | Optimal<br>$V_g$ | Minimum<br>$V_g$ | Maximum<br>$V_g$ | Initial<br>$V_g$ | Difference |
| 1          | 6                           | 1.02665          | .95000           | 1.05000          | 1.00000          | .02600     |
| 2          | 76                          | 1.01808          | .95000           | 1.05000          | 1.00000          | .01800     |
| 3          | 99                          | .97865           | .95000           | 1.05000          | 1.00000          | -.02100    |
| 5          | 108                         | 1.01670          | .95000           | 1.05000          | 1.00000          | .01600     |
| 7          | 118                         | 1.01919          | .95000           | 1.05000          | 1.00000          | .01900     |
| 9          | 125                         | 1.03406          | .95000           | 1.05000          | 1.02000          | .01400     |

|   | Bus | Optimal<br>$S_i$ | Minimum<br>$S_i$ | Maximum<br>$S_i$ |
|---|-----|------------------|------------------|------------------|
| 1 | 1   | 1.00             | .00              | 1.00             |
| 2 | 5   | .75              | .00              | 1.00             |
| 3 | 26  | 1.00             | .00              | 1.00             |
| 4 | 52  | 1.00             | .00              | 1.00             |
| 5 | 75  | .75              | .00              | 1.00             |
| 6 | 96  | 1.00             | .00              | 1.00             |
| 7 | 110 | .75              | .00              | 1.00             |
| 8 | 112 | .75              | .00              | 1.00             |

|    | From<br>Bus | To<br>Bus | Optimal<br>$t_{ij}$ | Minimum<br>$t_{ij}$ | Maximum<br>$t_{ij}$ | Initial<br>$t_{ij}$ | Difference |
|----|-------------|-----------|---------------------|---------------------|---------------------|---------------------|------------|
| 1  | 12          | 2         | .98037              | .90000              | 1.10000             | 1.02520             | -.04483    |
| 3  | 24          | 25        | 1.09988             | .90000              | 1.10000             | 1.02170             | .07818     |
| 4  | 53          | 11        | 1.06206             | .90000              | 1.10000             | 1.00000             | .06206     |
| 5  | 60          | 61        | 1.08553             | .90000              | 1.10000             | 1.02520             | .06033     |
| 6  | 60          | 61        | 1.08749             | .90000              | 1.10000             | 1.02520             | .06229     |
| 8  | 95          | 91        | 1.09258             | .90000              | 1.10000             | 1.02000             | .07258     |
| 9  | 95          | 99        | .94656              | .90000              | 1.10000             | 1.02960             | -.08304    |
| 10 | 97          | 44        | 1.08048             | .90000              | 1.10000             | 1.02520             | .05528     |
| 11 | 98          | 93        | .90785              | .90000              | 1.10000             | 1.02520             | -.11735    |
| 12 | 104         | 34        | .95335              | .90000              | 1.10000             | 1.00000             | -.04665    |
| 13 | 105         | 38        | 1.06065             | .90000              | 1.10000             | 1.02520             | .03545     |
| 14 | 129         | 132       | 1.05092             | .90000              | 1.10000             | 1.00000             | .05092     |
| 15 | 142         | 51        | .97726              | .90000              | 1.10000             | 1.07000             | -.09274    |
| 16 | 149         | 26        | 1.03573             | .90000              | 1.10000             | 1.00000             | .03573     |
| 17 | 149         | 26        | 1.03573             | .90000              | 1.10000             | 1.00000             | .03573     |

Table 5.9. Active Generation, and Transformer Tap Control Changes.

Case No. 4 Line Outage: 55 PLYMH 5 161 149 RAUN 5 161  
 Line Outage: 71 MONOA 5 161 85 CARRLL5 161

|   | Bus | Optimal<br>$P_g$ | Min<br>$P_g$ | Max<br>$P_g$ | Init.<br>$P_g$ | Difference |
|---|-----|------------------|--------------|--------------|----------------|------------|
| 1 | 73  | 17.8440          | 0.0          | 650.0        | 600.00         | -582.1560  |
| 2 | 76  | 1298.6490        | 0.0          | 1600.0       | 1555.00        | -256.3509  |
| 3 | 99  | 47.8411          | 0.0          | 350.0        | 300.90         | -253.0589  |
| 4 | 108 | 840.0533         | 0.0          | 1400.0       | 1001.12        | -161.0667  |
| 5 | 114 | 176.8265         | 0.0          | 300.0        | 241.00         | -64.1735   |
| 6 | 118 | 271.9135         | 0.0          | 300.0        | 193.00         | 78.9135    |
| 7 | 125 | 2975.2750        | 0.0          | 3000.0       | 2888.00        | 87.2751    |
| 8 | 131 | 748.8563         | 0.0          | 800.0        | 675.00         | 73.8563    |

|    | From<br>Bus | To<br>Bus | Optimal<br>$t_{ij}$ | Min<br>$t_{ij}$ | Max<br>$t_{ij}$ | Init.<br>$t_{ij}$ | Difference |
|----|-------------|-----------|---------------------|-----------------|-----------------|-------------------|------------|
| 1  | 4           | 115       | .94893              | 0.90            | 1.10            | 1.0000            | -.05107    |
| 2  | 12          | 2         | .96137              | 0.90            | 1.10            | 1.0252            | -.06383    |
| 3  | 18          | 37        | 1.02390             | 0.90            | 1.13            | 1.1193            | -.09540    |
| 4  | 20          | 53        | 1.05671             | 0.90            | 1.10            | 1.0000            | .05671     |
| 5  | 22          | 39        | 1.06470             | 0.90            | 1.13            | 1.1081            | -.04340    |
| 6  | 24          | 25        | 1.05889             | 0.90            | 1.10            | 1.0217            | .03719     |
| 7  | 52          | 118       | 1.08064             | 0.90            | 1.10            | 1.0429            | .03774     |
| 8  | 53          | 11        | .92511              | 0.90            | 1.10            | 1.0000            | -.07489    |
| 9  | 60          | 61        | .98270              | 0.90            | 1.10            | 1.0252            | -.04250    |
| 10 | 60          | 61        | .98117              | 0.90            | 1.10            | 1.0252            | -.04403    |
| 11 | 66          | 11        | .91639              | 0.90            | 1.10            | 1.0000            | -.08361    |
| 12 | 79          | 74        | 1.06858             | 0.90            | 1.10            | 1.0248            | .04378     |
| 13 | 93          | 42        | 1.08440             | 0.90            | 1.10            | 1.0248            | .05960     |
| 14 | 93          | 108       | .97521              | 0.90            | 1.10            | 1.0503            | -.07509    |
| 15 | 95          | 91        | 1.08275             | 0.90            | 1.10            | 1.0200            | .06275     |
| 16 | 95          | 99        | 1.07971             | 0.90            | 1.10            | 1.0296            | .05011     |
| 17 | 104         | 34        | 1.07700             | 0.90            | 1.10            | 1.0000            | .07700     |
| 18 | 110         | 112       | 1.06491             | 0.90            | 1.10            | 1.0000            | .06491     |
| 19 | 116         | 119       | 1.06760             | 0.90            | 1.10            | 1.0248            | .04280     |
| 20 | 129         | 132       | 1.04060             | 0.90            | 1.10            | 1.0000            | .04060     |
| 21 | 133         | 134       | .98843              | 0.90            | 1.10            | 1.0249            | -.03647    |
| 22 | 142         | 51        | .97131              | 0.90            | 1.10            | 1.0700            | -.09869    |
| 24 | 153         | 70        | .96150              | 0.90            | 1.10            | 1.0000            | -.03850    |
| 25 | 153         | 70        | .96150              | 0.90            | 1.10            | 1.0000            | -.03850    |
| 26 | 157         | 55        | 1.06089             | 0.90            | 1.10            | 1.0000            | .06089     |

Table 5.10. Active Generation Supply by Fictitious Generators for Case# 5.

Case No. 5 Line Outage: 55 PLYMH 5 161 149 RAUN 5 161  
 Line Outage: 161 KELOG 5 161 162 LEEDS 5 161

primal objective = .3629778538D-05  
 dual objective = -.1145864398D-04  
 max. power mismatch = .1761926754D-04  
 max. dual mismatch = .4434782645D-06

|     | Bus       | Optimal<br>$P_g$ | Min<br>$P_g$ | Max<br>$P_g$ | Init.<br>$P_g$ | Difference | Base<br>$P_g$ |
|-----|-----------|------------------|--------------|--------------|----------------|------------|---------------|
| 1   | 6         | 993.5707         | 0.0          | 1000.0       | 930.00         | 63.5707    | 930.00        |
| 2   | 73        | 8.5427           | 0.0          | 650.0        | 364.41         | -355.8673  | 600.00        |
| 3   | 76        | 1135.0806        | 0.0          | 1600.0       | 1421.02        | -285.9390  | 1555.00       |
| 4   | 99        | 339.7006         | 0.0          | 350.0        | 300.90         | 38.8006    | 300.90        |
| 5   | 101       | 166.3753         | 0.0          | 350.0        | 41.00          | 125.3753   | 122.00        |
| 6   | 108       | 1394.7930        | 0.0          | 1400.0       | 1001.12        | 393.6726   | 1001.12       |
| 7   | 114       | 291.4761         | 0.0          | 300.0        | 241.00         | 50.4761    | 241.00        |
| 8   | 118       | 295.2564         | 0.0          | 300.0        | 112.00         | 183.2564   | 193.00        |
| 9   | 121       | 791.3781         | 0.0          | 800.0        | 484.41         | 306.9681   | 720.00        |
| 10  | 125       | 2994.2120        | 0.0          | 3000.0       | 2888.00        | 106.2119   | 2888.00       |
| 11  | 130       | 790.4654         | 0.0          | 800.0        | 631.41         | 159.0554   | 755.00        |
| 12  | 131       | 791.9603         | 0.0          | 800.0        | 675.00         | 116.9603   | 675.00        |
| f1  | 163 (27)  | .0047            | 0.0          | 350.0        | 324.00         | -323.9953  |               |
| f2  | 164 (45)  | .0058            | 0.0          | 30.0         | 20.00          | -19.9942   |               |
| f3  | 165 (54)  | .0049            | 0.0          | 100.0        | 94.04          | -94.0351   |               |
| f4  | 166 (80)  | .0058            | 0.0          | 30.0         | 15.76          | -15.7542   |               |
| f5  | 167 (151) | .0051            | 0.0          | 30.0         | 24.00          | -23.9949   |               |
| f6  | 168 (161) | .0048            | 0.0          | 50.0         | 42.00          | -41.9952   |               |
| f7  | 169 (162) | .0054            | 0.0          | 40.0         | 30.00          | -29.9946   |               |
| f8  | 170 (15)  | .0045            | 0.0          | 200.0        | 160.00         | -159.9955  |               |
| f9  | 171 (18)  | .0054            | 0.0          | 50.0         | 40.40          | -40.3946   |               |
| f10 | 172 (28)  | .0054            | 0.0          | 50.0         | 38.47          | -38.4646   |               |
| f11 | 173 (29)  | .0057            | 0.0          | 30.0         | 28.31          | -28.3043   |               |
| f12 | 174 (56)  | .0057            | 0.0          | 30.0         | 25.29          | -25.2843   |               |
| f13 | 175 (57)  | .0053            | 0.0          | 60.0         | 48.48          | -48.4747   |               |

Table 5.11. Active Generation Supply by Fictitious Generators for Case# 6.

Case No. 6 (17) Gen. Outage: 76 NEAL34G 24  
 Gen. Outage: 131 NEBCY1G 18

primal objective = .3273372182D-05  
 dual objective = -.1301776166D-04  
 max. power mismatch = .8799596186D-04  
 max. dual mismatch = .1441888771D-06

|     | Bus       | Optimal<br>$P_g$ | Min<br>$P_g$ | Max<br>$P_g$ | Init.<br>$P_g$ | Difference | Base<br>$P_g$ |
|-----|-----------|------------------|--------------|--------------|----------------|------------|---------------|
| 1   | 6         | 987.0786         | 0.0          | 1000.0       | 930.00         | 57.0786    | 930.00        |
| 2   | 73        | 1037.3590        | 0.0          | 1150.0       | 600.00         | 437.3589   | 600.00        |
| 3   | 99        | 300.7892         | 0.0          | 350.0        | 300.90         | -.1108     | 300.90        |
| 4   | 101       | 159.4391         | 0.0          | 350.0        | 122.00         | 37.4391    | 122.00        |
| 5   | 108       | 1344.6420        | 0.0          | 1400.0       | 1001.12        | 343.5216   | 1001.12       |
| 6   | 114       | 284.9729         | 0.0          | 300.0        | 241.00         | 43.9729    | 241.00        |
| 7   | 118       | 289.7166         | 0.0          | 300.0        | 193.00         | 96.7166    | 193.00        |
| 8   | 121       | 785.8536         | 0.0          | 800.0        | 720.00         | 65.8536    | 720.00        |
| 9   | 125       | 2983.3930        | 0.0          | 3000.0       | 2888.00        | 95.3934    | 2888.00       |
| 10  | 130       | 784.9462         | 0.0          | 800.0        | 755.000        | 29.9462    | 755.00        |
| f1  | 163 (20)  | .0045            | 0.0          | 50.0         | 40.90          | -40.8955   |               |
| f2  | 164 (40)  | .0044            | 0.0          | 60.0         | 52.88          | -52.8756   |               |
| f3  | 165 (87)  | .0044            | 0.0          | 20.0         | 16.91          | -16.9056   |               |
| f4  | 166 (103) | .0040            | 0.0          | 340.0        | 322.00         | -321.9960  |               |
| f5  | 167 (111) | .0044            | 0.0          | 70.0         | 65.41          | -65.4056   |               |
| f6  | 168 (113) | .0046            | 0.0          | 40.0         | 32.70          | -32.6954   |               |
| f7  | 169 (139) | .0045            | 0.0          | 20.0         | 10.10          | -10.0955   |               |
| f8  | 170 (142) | .0045            | 0.0          | 30.0         | 27.09          | -27.0855   |               |
| f9  | 171 (157) | .0046            | 0.0          | 40.0         | 32.00          | -31.9954   |               |
| f10 | 172 (160) | .0045            | 0.0          | 20.0         | 14.40          | -14.3955   |               |
| f11 | 173 (30)  | .0041            | 0.0          | 200.0        | 190.20         | -190.1959  |               |
| f12 | 174 (38)  | .0045            | 0.0          | 20.0         | 14.76          | -14.7555   |               |
| f13 | 175 (46)  | .0044            | 0.0          | 70.0         | 65.31          | -65.3056   |               |
| f14 | 176 (59)  | .0042            | 0.0          | 120.0        | 104.43         | -104.4258  |               |
| f15 | 177 (91)  | .0044            | 0.0          | 60.0         | 51.24          | -51.2356   |               |
| f16 | 178 (94)  | .0042            | 0.0          | 180.0        | 164.00         | -163.9958  |               |
| f17 | 179 (105) | .0045            | 0.0          | 30.0         | 24.84          | -24.8355   |               |



Table 5.12. Active Generation Supply by Fictitious Generators for Case# 7.

Case No. 7 Line Outage: 55 PLYMH 5 161 149 RAUN 5 161  
 Line Outage: 55 PLYMH 5 161 162 LEEDS 5 161

primal objective = .1711047953D-04  
 dual objective = -.2210446411D-04  
 max. power mismatch = .3658650046D-04  
 max. dual mismatch = .1025270371D-06

|     | Bus       | Optimal<br>$P_{fg}$ | Min<br>$P_{fg}$ | Max<br>$P_{fg}$ | Init.<br>$P_{fg}$ | Difference | Base<br>$P_g$ |
|-----|-----------|---------------------|-----------------|-----------------|-------------------|------------|---------------|
| 1   | 6         | 985.0694            | 0.0             | 1000.0          | 930.00            | 55.0694    | 930.00        |
| 2   | 73        | 23.0953             | 0.0             | 650.0           | 395.41            | -372.3147  | 600.00        |
| 3   | 76        | 1237.6484           | 0.0             | 1600.0          | 1421.02           | -183.3720  | 1555.00       |
| 4   | 99        | 308.7199            | 0.0             | 350.0           | 300.90            | 7.8199     | 300.90        |
| 5   | 101       | 162.5759            | 0.0             | 350.0           | 41.00             | 121.5759   | 122.00        |
| 6   | 108       | 1372.4860           | 0.0             | 1400.0          | 1001.12           | 371.3665   | 1001.12       |
| 7   | 114       | 276.8409            | 0.0             | 300.0           | 241.00            | 35.8409    | 241.00        |
| 8   | 118       | 288.8139            | 0.0             | 300.0           | 112.00            | 176.8139   | 193.00        |
| 9   | 121       | 775.6407            | 0.0             | 800.0           | 515.41            | 260.2307   | 720.00        |
| 10  | 125       | 2985.2110           | 0.0             | 3000.0          | 2888.00           | 97.2107    | 2888.00       |
| 11  | 130       | 788.5820            | 0.0             | 800.0           | 631.41            | 157.1720   | 755.00        |
| 12  | 131       | 779.0364            | 0.0             | 800.0           | 675.00            | 104.0364   | 675.00        |
| f1  | 163 (27)  | .0108               | 0.0             | 350.0           | 324.00            | -323.9892  |               |
| f2  | 164 (54)  | .0115               | 0.0             | 100.0           | 94.04             | -94.0285   |               |
| f3  | 165 (80)  | .0141               | 0.0             | 20.0            | 15.76             | -15.7459   |               |
| f4  | 166 (151) | .0122               | 0.0             | 30.0            | 24.00             | -23.9878   |               |
| f5  | 167 (162) | .0132               | 0.0             | 40.0            | 30.00             | -29.9868   |               |
| f6  | 168 (15)  | .0106               | 0.0             | 180.0           | 160.00            | -159.9894  |               |
| f7  | 169 (18)  | .0127               | 0.0             | 50.0            | 40.40             | -40.3873   |               |
| f8  | 170 (28)  | .0130               | 0.0             | 50.0            | 38.47             | -38.4570   |               |
| f9  | 171 (29)  | .0132               | 0.0             | 40.0            | 28.31             | -28.2968   |               |
| f10 | 172 (56)  | .0130               | 0.0             | 40.0            | 25.29             | -25.2770   |               |
| f11 | 173 (57)  | .0125               | 0.0             | 60.0            | 48.48             | -48.4675   |               |

Table 5.13. Voltage Set Point, Active Generation, and Transformer Tap Control Changes.

Case No. 5 Line Outage: 55 PLYMH 5 161 149 RAUN 5 161  
 Line Outage: 161 KELOG 5 161 162 LEEDS 5 161

|   | Bus | Optimal<br>$V_g$ | Minimum<br>$V_g$ | Maximum<br>$V_g$ | Initial<br>$V_g$ | Difference |
|---|-----|------------------|------------------|------------------|------------------|------------|
| 1 | 6   | 1.02433          | .95000           | 1.05000          | 1.00000          | .02400     |
| 2 | 73  | 1.01417          | .95000           | 1.05000          | 1.00000          | .01400     |
| 3 | 76  | 1.01798          | .95000           | 1.05000          | 1.00000          | .01700     |
| 4 | 101 | 1.02392          | .95000           | 1.05000          | 1.00000          | .02300     |
| 5 | 108 | 1.02759          | .95000           | 1.05000          | 1.00000          | .02700     |
| 6 | 118 | 1.02001          | .95000           | 1.05000          | 1.00000          | .02000     |
| 7 | 125 | 1.04537          | .95000           | 1.05000          | 1.02000          | .02500     |
| 8 | 130 | 1.01755          | .95000           | 1.05000          | 1.03000          | -.01200    |

|    | From<br>Bus | To<br>Bus | Optimal<br>$t_{ij}$ | Minimum<br>$t_{ij}$ | Maximum<br>$t_{ij}$ | Initial<br>$t_{ij}$ | Difference |
|----|-------------|-----------|---------------------|---------------------|---------------------|---------------------|------------|
| 1  | 12          | 2         | .97619              | .90000              | 1.10000             | 1.02520             | -.04901    |
| 2  | 18          | 37        | 1.03097             | .90000              | 1.13000             | 1.11930             | -.08833    |
| 3  | 20          | 53        | 1.05147             | .90000              | 1.10000             | 1.00000             | .05147     |
| 4  | 24          | 25        | 1.09333             | .90000              | 1.10000             | 1.02170             | .07163     |
| 5  | 60          | 61        | .97692              | .90000              | 1.10000             | 1.02520             | -.04828    |
| 6  | 60          | 61        | .97567              | .90000              | 1.10000             | 1.02520             | -.04953    |
| 7  | 93          | 42        | 1.07476             | .90000              | 1.10000             | 1.02480             | .04996     |
| 8  | 95          | 91        | 1.08180             | .90000              | 1.10000             | 1.02000             | .06180     |
| 9  | 96          | 101       | .99883              | .90000              | 1.10000             | 1.02960             | -.03077    |
| 10 | 104         | 34        | 1.04166             | .90000              | 1.10000             | 1.00000             | .04166     |
| 11 | 105         | 38        | .97957              | .90000              | 1.10000             | 1.02520             | -.04563    |
| 12 | 110         | 112       | 1.04992             | .90000              | 1.10000             | 1.00000             | .04992     |
| 13 | 116         | 119       | 1.05744             | .90000              | 1.10000             | 1.02480             | .03264     |
| 14 | 128         | 72        | 1.05406             | .90000              | 1.10000             | 1.00000             | .05406     |
| 15 | 133         | 134       | .99312              | .90000              | 1.10000             | 1.02490             | -.03178    |
| 16 | 142         | 51        | 1.00114             | .90000              | 1.10000             | 1.07000             | -.06886    |
| 17 | 153         | 70        | .96299              | .90000              | 1.10000             | 1.00000             | -.03701    |
| 18 | 153         | 70        | .96299              | .90000              | 1.10000             | 1.00000             | -.03701    |
| 19 | 157         | 55        | 1.04363             | .90000              | 1.10000             | 1.00000             | .04363     |

Table 5.14. Voltage Set Point, Active Generation, and Transformer Tap Control Changes.

Case No. 6 (17) Gen. Outage: 76 NEAL34G 24  
 Gen. Outage: 131 NEBCY1G 18

|   | Bus | Optimal<br>$V_g$ | Minimum<br>$V_g$ | Maximum<br>$V_g$ | Initial<br>$V_g$ | Difference |
|---|-----|------------------|------------------|------------------|------------------|------------|
| 1 | 6   | 1.02151          | .95000           | 1.05000          | 1.00000          | .02100     |
| 2 | 73  | 1.03132          | .95000           | 1.05000          | 1.00000          | .03100     |
| 3 | 101 | 1.01609          | .95000           | 1.05000          | 1.00000          | .01600     |
| 4 | 108 | 1.02313          | .95000           | 1.05000          | 1.00000          | .02300     |
| 5 | 118 | 1.02018          | .95000           | 1.05000          | 1.00000          | .02000     |
| 6 | 121 | 1.01758          | .95000           | 1.05000          | 1.00000          | .01700     |
| 7 | 125 | 1.04699          | .95000           | 1.05000          | 1.02000          | .02600     |

|    | From<br>Bus | To<br>Bus | Optimal<br>$t_{ij}$ | Minimum<br>$t_{ij}$ | Maximum<br>$t_{ij}$ | Initial<br>$t_{ij}$ | Difference |
|----|-------------|-----------|---------------------|---------------------|---------------------|---------------------|------------|
| 1  | 12          | 2         | .98631              | .90000              | 1.10000             | 1.02520             | -.03889    |
| 2  | 18          | 37        | 1.05058             | .90000              | 1.13000             | 1.11930             | -.06872    |
| 3  | 24          | 25        | 1.05581             | .90000              | 1.10000             | 1.02170             | .03411     |
| 4  | 26          | 76        | .98578              | .90000              | 1.10000             | 1.04000             | -.05422    |
| 5  | 60          | 61        | .98751              | .90000              | 1.10000             | 1.02520             | -.03769    |
| 6  | 60          | 61        | .98735              | .90000              | 1.10000             | 1.02520             | -.03785    |
| 7  | 66          | 11        | .95911              | .90000              | 1.10000             | 1.00000             | -.04089    |
| 8  | 93          | 42        | 1.05821             | .90000              | 1.10000             | 1.02480             | .03341     |
| 9  | 93          | 108       | 1.01035             | .90000              | 1.10000             | 1.05030             | -.03995    |
| 10 | 95          | 91        | 1.05219             | .90000              | 1.10000             | 1.02000             | .03219     |
| 11 | 96          | 101       | 1.00511             | .90000              | 1.10000             | 1.02960             | -.02449    |
| 12 | 104         | 34        | 1.04647             | .90000              | 1.10000             | 1.00000             | .04647     |
| 13 | 110         | 112       | 1.03927             | .90000              | 1.10000             | 1.00000             | .03927     |
| 14 | 110         | 114       | 1.00765             | .90000              | 1.10000             | 1.03980             | -.03215    |
| 15 | 112         | 121       | 1.01622             | .90000              | 1.10000             | 1.04990             | -.03368    |
| 16 | 116         | 119       | 1.06023             | .90000              | 1.10000             | 1.02480             | .03543     |
| 17 | 142         | 51        | 1.02983             | .90000              | 1.10000             | 1.07000             | -.04017    |
| 18 | 149         | 26        | 1.06857             | .90000              | 1.10000             | 1.00000             | .06857     |
| 19 | 149         | 26        | 1.06857             | .90000              | 1.10000             | 1.00000             | .06857     |
| 20 | 157         | 55        | 1.03504             | .90000              | 1.10000             | 1.00000             | .03504     |

Table 5.15. Active Generation and Transformer Tap Control Changes.

Case No. 7 Line Outage: 55 PLYMH 5 161 149 RAUN 5 161  
 Line Outage: 55 PLYMH 5 161 162 LEEDS 5 161

|    | From<br>Bus | To<br>Bus | Optimal<br>$t_{ij}$ | Minimum<br>$t_{ij}$ | Maximum<br>$t_{ij}$ | Initial<br>$t_{ij}$ | Difference |
|----|-------------|-----------|---------------------|---------------------|---------------------|---------------------|------------|
| 1  | 12          | 2         | .97610              | .90000              | 1.10000             | 1.02520             | -.04910    |
| 2  | 18          | 37        | 1.02339             | .90000              | 1.13000             | 1.11930             | -.09591    |
| 3  | 20          | 53        | 1.04819             | .90000              | 1.10000             | 1.00000             | .04819     |
| 4  | 24          | 25        | 1.08474             | .90000              | 1.10000             | 1.02170             | .06304     |
| 5  | 60          | 61        | .97207              | .90000              | 1.10000             | 1.02520             | -.05313    |
| 6  | 60          | 61        | .96579              | .90000              | 1.10000             | 1.02520             | -.05941    |
| 7  | 79          | 74        | 1.05582             | .90000              | 1.10000             | 1.02480             | .03102     |
| 8  | 93          | 42        | 1.07478             | .90000              | 1.10000             | 1.02480             | .04998     |
| 9  | 93          | 108       | 1.01891             | .90000              | 1.10000             | 1.05030             | -.03139    |
| 10 | 95          | 91        | 1.06705             | .90000              | 1.10000             | 1.02000             | .04705     |
| 11 | 104         | 34        | 1.04985             | .90000              | 1.10000             | 1.00000             | .04985     |
| 12 | 110         | 112       | 1.04997             | .90000              | 1.10000             | 1.00000             | .04997     |
| 13 | 116         | 119       | 1.06198             | .90000              | 1.10000             | 1.02480             | .03718     |
| 14 | 133         | 134       | .99454              | .90000              | 1.10000             | 1.02490             | -.03036    |
| 15 | 142         | 51        | 1.01384             | .90000              | 1.10000             | 1.07000             | -.05616    |
| 16 | 157         | 55        | 1.04772             | .90000              | 1.10000             | 1.00000             | .04772     |

Table 5.16. Reactive Generation Before and After Optimization.

| #   | Gen. Bus<br>Name | Case# 5 |         | Case# 6 |         | Case# 7 |         |
|-----|------------------|---------|---------|---------|---------|---------|---------|
|     |                  | Before  | After   | Before  | After   | Before  | After   |
| 6   | 6R1G 22          | 348.01  | 400.00  | 195.58  | 363.54  | 347.78  | 344.13  |
| 73  | NEAL12G 20       | 153.93  | 147.56  | 46.37   | 267.00  | 159.79  | 153.50  |
| 76  | NEAL34G 24       | 402.01  | 369.14  | **      | **      | 403.05  | 253.74  |
| 99  | PRARK4G 18       | 50.62   | 49.55   | 0.40    | 37.64   | 50.28   | 46.52   |
| 101 | MTOW 3G 14       | 38.60   | 38.60   | 21.49   | 38.60   | 38.60   | 38.60   |
| 108 | AROL 1G 22       | 195.54  | 432.63  | 76.94   | 318.65  | 194.01  | 360.50  |
| 114 | C.BL12G 14       | 33.00   | 14.50   | 32.84   | 29.67   | 33.00   | 11.59   |
| 118 | DPS 57G 14       | 100.00  | 100.00  | 30.38   | 97.31   | 100.00  | 95.88   |
| 121 | C.BL 3G 24       | 236.75  | 204.72  | 143.89  | 247.08  | 239.54  | 200.72  |
| 125 | PALM710 345      | -414.82 | -357.05 | -669.83 | -378.88 | -415.99 | -364.27 |
| 130 | FT.CL1G 22       | 235.08  | 232.08  | 144.96  | 250.63  | 233.87  | 223.72  |
| 131 | NEBCY1G 18       | 212.67  | 210.31  | **      | **      | 212.22  | 165.50  |

\*\* means the generator is part of the double contingency.

## A probabilistic improvement in defining operating rules against voltage collapse

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**Abstract** - A risk-based statistical approach has been carried out to assess voltage stability limits in the South Eastern part of France's subsystem and to construct new operating rules to avoid voltage collapse. The possibility of taking a large number of power system states as well as the uncertainties of the models into account enables us to assess accurately and robustly the stability limits of the system. The statistical methods allow one to find simple expressions of these limits and so to forecast when contingencies are very likely to lead to a collapse. After this statistical study, a probabilistic refinement introducing probabilities of power system states has been carried out to validate these rules. Bayesian Belief Networks proved to be helpful for the evaluation of a power system state probability, because of their ability to model the uncertainties and dependencies of variables.

**Keywords** - voltage collapse, operating rules, risk-based statistical approach, probabilistic approach, probability of a power system state, Bayesian Belief Network

### 1. Introduction

As most countries in the world have difficulties in building new transmission lines, the amount of energy transmitted through the existing EHV power systems increases with the load level. This tendency is strongly reinforced by the deregulation and increase of power exchanges. The risk of collapse and especially of voltage collapse becomes higher. In an operating context, the question of the prevention of such collapse is sensitive. This is the reason why a lot of work has been done to find indexes of voltage collapse proximity [1]. In France the operators have to apply rules that give them instructions to follow when these indexes are passed.

In fact, this area is weakly interconnected and is remote from the power plants that produce the cheapest energy. Moreover, environmental constraints have been making the reinforcement of the power system very difficult. Due to this, a single line or generator tripping may, in some conditions, lead this area to a voltage collapse. The operator often has no other alternative but to start up near but expensive generating units as a preventive measure. It is therefore very important to assess the risks of a power system state correctly in order to take the right decision at the right time. This is why French dispatchers use operating rules. Until 1999, these rules consisted of checking the sum of the active power transfers on the west-east lines that feed the area. For a given load level and a number of running plants, charts gave the maximum allowed transfer on these lines. Due to the fact that these rules were a little bit complicated to apply, they have been simplified in practice: the value of the west-east flow was the only signal really checked and expensive power plants were certainly used more frequently than they should have been. For this reason, and also because of these rules being devised about ten years ago, it was necessary to review them.

A risk-based statistical approach has been carried out to assess voltage stability limits in the South Eastern part of France's subsystem and to construct new operating rules to avoid voltage collapse. The possibility of taking a large number of power system states as well as the uncertainties of the models into account enables us to assess accurately and robustly the stability limits of the system. The statistical methods allow one to find simple expressions of these limits and so to forecast when contingencies are very likely to lead to a collapse. After this statistical study, a probabilistic refinement introducing probabilities of power system states has been carried out to validate these rules.

In Section II of this paper, we describe the risk-based methodology using a statistical approach that has been carried out to devise new operating rules. Section III presents the need for a probabilistic approach and the method of evaluation of the probabilities of power system states. The study results and the comparison between the statistical and the probabilistic studies are shown in Section IV. Section V concludes.

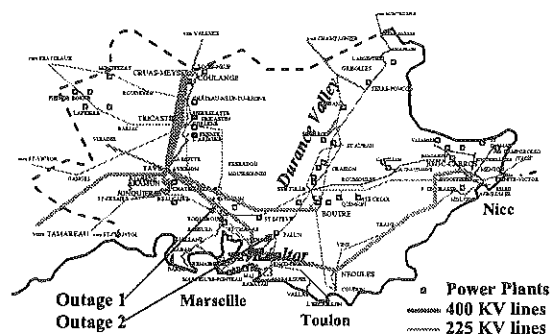


Fig. 1. The South Eastern part of France Power system

The southeastern part of the French power system, near the Riviera, is the part which is the most liable to voltage collapse.

## II. First step: A statistical approach to defining operating rules

### A. Overview of the method

Previous work, achieved with the University of Liege, had already shown the interest of a statistical methodology to assess power system security [2] and especially to construct voltage security criteria [3]. It was so decided to carry out a study with this statistical approach and to focus on the three following goals:

1. to find some criteria based on signals that are measurable before the contingency,
2. to make these criteria as simple as possible,
3. to devise robust criteria and to be ensured of their validity domain.

### B. Method

Three main steps can be distinguished in the statistical method:

1. generation of a set of 10,000 different power system states, randomly defined with various levels of consumption, production plans and power system topologies
2. simulation of contingencies, and assessment of the consequences using power margins
3. statistical analysis of the results and rules construction.

### C. The generation of a set of power system states

This stage is the most sensitive one of such a study, and often the most computationally expensive (papers [4] [10] address this more in depth). Indeed, the confidence you have in the results reflects the confidence you have in the set of system states that is generated. To devise a robust criterion that is valuable all the time, this set must contain all the possible power system states, even those that have little probability of occurring. As evidence, it is also very important that the sample contain both acceptable and unacceptable system states to be able to find the limit between these two domains.

First of all, an original system state must be chosen to be the basis for our model. In this study about the South Eastern part of France area, the whole French EHV system was represented. It includes about 1200 buses, 1400 400 kV, 225kV and 150 kV lines, 430 transformers and 230 power plants. A particular focus was brought on the southeast area. In this region, each load was represented by a quite complex model including shunt compensators and a cascade of two transformers equipped with On-Load-Tap-Changers. Moreover, the Secondary Voltage Control (SVC) was modeled [5].

Secondly, a set of about 10,000 different system states was generated from the original one. This is done by applying randomly defined variations on our model. A power system state is mainly defined by three parameters: the load level, the unit commitment and the power system topology. To make up our set, the variations of each parameter are specified

independently of the others by the means of probability distributions. Afterwards, the set is generated by a random sampling of these parameters.

As for the power plants, production areas were defined to gather generators that play the same role, e.g. hydro plants of the same valley, neighboring nuclear plants... In each of these areas, the number of generators that should have been started and their production level were randomly drawn in respect to the specified distribution law.

As for the topology, the probabilistic distributions were chosen in such a way that all the lines were in service in 50 % of the system states, one line was out of service in 30 % of the cases and two lines in the 20 % remaining.

Moreover, using a statistical approach allows us to take the uncertainties of the system into account. So, unknown parameters are randomized to a certain extent in order to avoid too high a correlation between the results of the study and some arbitrary choices of parameter values. For this study about the South Eastern part of France, we estimated that three power system characteristics might influence the results since they were not very well known: these are the load models, the generator overexcitation limits and the voltage profile in the studied area.

After the random sampling of the system state characteristics, the power system states are built up by computing load flows and simulations without disturbances. The system states that are obtained are then sorted in order to keep only the stable ones, without overflows and with correct voltage profiles.

### D. Outage simulation and consequence assessment

Once the set of system states is generated, the second stage of the risk-based method consists of simulating contingencies and assessing the consequences.

The two most severe N-1 contingencies of the area have been simulated, using the dynamic simulation tools EUROSTAG [6] and ASTRE [7]. The first one is the tripping of one of the 400 kV lines that feed the area (see outage 1 on Fig. 1). The second one is the loss of a 600 MW generating plant near Marseilles (see outage 2 on Fig. 1). When the system remains stable after the contingency, a steady load increase is simulated from the new equilibrium point up to the loss of stability. The system is considered to be unstable when one of the "reactive power dispatch coefficients" changes sign.

We now had to define a way to qualify the consequences of our scenarios. In practice, we decided with the operating center, that a voltage margin [representing the load augmentation until the voltage drops under one of the tap changer blocking thresholds] of 200 MW had to be kept to maintain system security. This value represents about 30 minutes of load increase during the morning load rise. Thus, all the system states whose voltage margin was over 200 MW were considered to be *acceptable* and those that were unstable or whose voltage margin was less than 200 MW were considered to be *unacceptable*.

### E. Result analysis

Once a convenient set of system states has been generated and each of these system states has been qualified, the third stage of the method consists of finding the correlation between the variables that describe the pre-disturbance state and the qualification of the system state that results from the disturbance simulations (acceptable or not).

A method based on decision trees [8] [9] determines for the 600 variables describing the pre-disturbance states (voltages, power flows, load levels, generation characteristics and composite variables) the most efficient variables and the best threshold associated with the selected variable. These principles are developed in paper [10].

When we looked for the variables that were the most efficient for classifying the whole set of system states, it appeared that three groups of variables could be distinguished: the bus voltages along the southern 400 kV line, the rates of reactive generation in the eastern production areas and some reactive transits. The most efficient criteria for determining if a system state is acceptable are those that combine one variable of each group (or at least of two of them). This reflects the two possible causes of a voltage collapse: failure of reactive reserve, or the growth of reactive losses in the lines due to excessive power flows. As a consequence, the decision trees obtained are very simple and contain only 2 or 3 nodes.

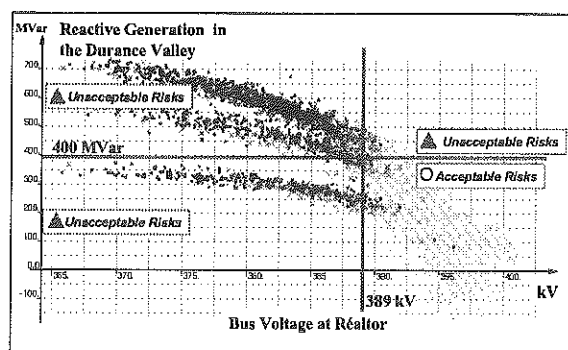


Fig. 2. Visualization of a criterion containing 2 tests

Fig. 2 illustrates one of the criteria obtained. Each system state of the set is located in a two-dimensional space. The y-axis represents the sum of the reactive generations of all the hydro power plants of the Durance Valley, and the x-axis represents the bus voltage at Réalator, near Marseilles. The darker points indicate the system states where the risks are unacceptable. The lighter ones show the acceptable system states. The criterion we want to illustrate says: "If the voltage level at Réalator drops under 389 kV or if all the power plants of the Durance Valley supply more than 400 Mvar together, then the system state is unacceptable". The two tests split the space in 4 quarters: to be acceptable, a system state must be located in the bottom right one, says the rule.

However, one can see that this criterion does not classify all the system states of the set perfectly. Some unacceptable system

states are in the acceptable area: the risk might not be detected. On the other hand, some acceptable system states, which are in the unacceptable area might lead to false alarms. Several criteria were devised, and the rates of the different types of errors were calculated (the criterion construction and its evaluation were carried out on independent subsets of system states). For the example shown in Fig. 2, the non-detection rate was 1.4%, the false alarm rate was 3.6% and the global error rate was 5%.

This evaluation of what we call the residual risk (unacceptable system states in the acceptable area) does not take the weight of the considered system states into account (each system state has the same probability). Consequently, the probabilities of those system states are needed to have a better measure of the risks taken with a specific operating rule. This is the subject of parts III and IV of this paper.

Once checked that measurements of the variables were available, one of the best combinations was selected to construct an operating rule.

### F. Study Results and Operation feedback

Seven statistical operating rules were determined during the study. The actual rule has been deduced from these rules. The rule obtained is very simple: it consists of checking the level of three variables available in the control center: the voltage on the Réalator bus, the reactive generation of the hydro power plants in the Durance valley and the reactive import of the east area (see Fig. 1).

The selected criterion says: "If the bus voltage in Réalator drops under 390 kV, if the reactive generation of the hydro power plants of the Durance valley is over 390 Mvar or if the reactive import of the east area is higher than 260 Mvar, then the system state is considered to be unacceptable".

In a first stage and for practical reasons, it has been decided to use this criterion only in real-time operation. The decision to start up expensive power plants is still taken the day before in operation planning with the previous rules, i.e. when west-east power flow prediction is higher than 2600 MW. However, in real time operation, if the new criterion says that the system state is acceptable, the new rule obliges the dispatcher to decrease the power generated by these plants to the minimum.

During the first 3 months of 1998, the west-east transit went over 2600 MW about one third of the time. With the previous rules, oil-fired plants should have been running the whole time to keep the transit level under this threshold. The new rules have allowed the west-east flow to reach more than 3000 MW without risks. The power generated by the oil-fired plants near Réalator has therefore been reduced. 70 GWh of energy were re-dispatched by cheaper power plants. Thanks to this, the system operator has saved more than \$ 1 M during this period, and \$ 2M in 1998. Since 1999, more than \$ 1M has been saved each year.

### G. Conclusion

The study of the voltage security on the South Eastern part of France's subsystem has shown the great interest of a risk-based methodology using a statistical approach for such problems. The ability to take a large number of different power system states into account allows one to assess very accurately the stability limits of the system. The statistical methods and especially the decision tree method make it very easy to construct algebraic criteria that describe these limits. These methods help to find the signals that are the most efficient to forecast problems and to calculate thresholds that have to be checked. Moreover, the possibility of modeling uncertainties enables one to make the criteria very robust.

In addition the operation feedback has shown the advantages for utilities of carrying out such studies. Not only has the system operator improved power system security thanks to better knowledge of the distance between acceptable and unacceptable system states, it has also saved a great amount of money in authorizing operation nearer to the stability limits. This has been done with a control of the risks that have been taken. After this first study Electricité de France has developed the tool ASSESS [25] which integrates a sampling tool, static and dynamic simulation tools (ASTRE [7], EUROSTAG [6]) and statistical result analysis tools. It will be very helpful to perform such studies in the future.

This statistical methodology is a first step for a full risk-based security assessment on power systems. The next step of the methodology is to associate probabilities of the considered power system states to the statistical approach in order to weigh the acceptable and unacceptable risks. Such an approach was tested on a security study undertaken for the South Eastern part of France to improve its operating rules, and is presented in the next part of this paper.

### III. Second step: A probabilistic approach using probabilities of system states

We have seen that statistical methods, and especially the decision tree method, can be very powerful for describing stability limits, taking a large number of different power system states into account.

However, some of these system states may play a crucial role in the determination of the rule, although they are of very low probability. The next step should be to take the probabilities of the studied system states into account to obtain more accurate rules. It is based on the weighting of the decision tree by the probabilities of the system states, and then requires the evaluation of the probabilities of the system operating states, which is not so easy: the variables that characterize the system state are mutually *dependent*, i.e. the value of each variable influences the value of each of the other variables.

These phenomena of dependencies are well-known and have significant impact on system state probabilities. A power system can reside in an extremely large number of possible states, depending on the state of each transmission line, each generating unit, and the load level at each bus. The state of the

power system may be described by hundreds of mutually-dependent, multi-state variables. Because of bus load uncertainty and the unpredictability of events affecting the system (forced outages of lines, weather effects, etc.), the power system state has to be modeled as a random variable, with a complex probability distribution.

This part of the paper will develop a methodology for calculating these system state probabilities taking these dependencies into account. It is based on a recent mathematical technique: **Bayesian Belief Networks**. The application of the approach to the study of a **simplified model** of the South Eastern part of France's power system is presented here, with the concerned variables and their dependencies, and then the calculation of the probabilities of system states.

#### A. Dependent variables of a power system

*A.1. Previous work on dependent variables for system operating states probability:* Many authors have pointed out the dependencies between the variables of a power system operating state:

- dependencies between the load levels in different areas of a power system, and between the forced line outages due to weather [14] [23] [24],
- weather influences the generation system (e.g. level of dam reservoirs), the transmission system (e.g. forced line outages due to storms), and the load (which is strongly correlated to temperature). Many papers [11, 13, 15, 16, 18, 19, 20, 21, 22] insist on the importance of weather parameters in the analysis of a power system,
- well-known dependencies between contingencies [12].

*A.2. Bayesian belief networks:* Bayesian Belief Networks (BBN) are more and more commonly used nowadays to predict, diagnose, control or simulate the behavior of complex systems. Their fields of applications include civil industry, defense, software design, health care, finance and marketing.

Mathematically, a Bayesian Belief Network is a graph in which the nodes represent random variables and the links represent probabilistic dependencies [17].

BBN models generalize many classical reliability models, such as fault-trees. They are more powerful in terms of modeling abilities than fault-trees, because they can handle multi-state systems and dependencies.

The BBN software NETICA [17] was used in the study. NETICA is very easy to use: the model is keyed in through a Graphical User Interface. The user specifies the values of some of the variables. The software automatically updates the probabilities of the rest of the variables and also calculates the probability of the system states. The stochastic dependencies between the variables are taken into account.



### B. CASE STUDY

This chapter describes the variables that characterize the South Eastern part of France's power system. All the dependencies presented here have been identified and quantified in collaboration with operators of the concerned area.

**B.1. Load:** The load demand at different sites of the area depends on:

- the date (e.g. use of electric heating in winter, use of air conditioners in summer)
- the ambient temperature,
- the time (the load varies on a daily basis, e.g. the load is lower at night)
- the day of the week (the load is significantly lower on Sundays and public holidays)
- the weather conditions (the load is higher by about 200 MW when the weather is cloudy)

**B.2. Topology:** The average power generation in the area is about 2,000 MW. The average load (on a yearly basis) is 3,500 MW. Power importation from other areas is thus necessary. For simplicity's sake, we shall consider that the power is imported through two 400 kV transmission lines, called 'line1' and 'line2'.

In this example of application we shall just consider these two lines, which are the two most important in the area, to simplify the model and the presentation of the method. Other lines (and their dependencies) have to be considered for a complete study. That study has been carried out and its results are presented in part IV.

Planned outages of lines (for maintenance) are preferably carried out during the spring months for line1, and the summer months for line2. The two lines are never maintained simultaneously.

The lines may also be affected by contingencies, leading to unscheduled outages.

**B.3. Generation:** Depending on the states of line1 and line2, a certain amount of power is imported into the area. This amount also depends on the ambient temperature: when the weather is cool, the transmission lines tolerate a higher maximal current.

To simplify matters, let us accept that the local power generation (thermal and hydraulic) is adjusted according to the imported energy so as to satisfy the load.

### C. System Modeling

The state of the power system in the area is characterized by the following variables:

Temperature, Hour, Day, Weather, Season, Load, Line1, Line2, Imported Power, Generated Power

A BBN model of the system (including the probability distribution of the variables and their dependencies – § A.2) has been built using NETICA® (Fig 3) [17]. This software is easy to use, and is not limited by numbers of nodes and links.

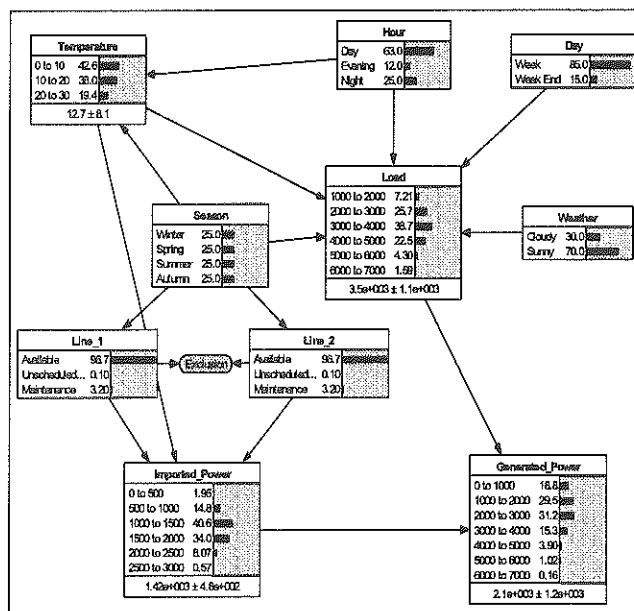


Figure 3: the NETICA interface: BBN model of the power system

### D. Results

**D.1. Probabilities of 4 system states:** This model was used to evaluate the probabilities of each of the 10,000 system states.

Table 1 shows the probabilities of four operating states, characterized by four variables: local load, local generated power, and conditions of line1 and line2.

| System state | Load (MW) | Generation (MW) | line1 | line2       | Probability |
|--------------|-----------|-----------------|-------|-------------|-------------|
| 1            | 4,154     | 1,333           | OK    | maintenance | 0,000713 %  |
| 2            | 5,219     | 2,114           | OK    | OK          | 0,121 %     |
| 3            | 4,462     | 1,534           | OK    | OK          | 0,579 %     |
| 4            | 3,309     | 1,333           | OK    | OK          | 15,2 %      |

Table 1: probabilities of 4 operating states

**D.2. Comments:** The system state probabilities appear to be different by several orders of magnitude.

System state 1 appears to be very unlikely. Line2 is maintained, which happens only 5 days per year. Moreover, maintenance of line2 occurs preferentially in summer months,

and a load greater than 4,000 MW is very unlikely in summer months.

System state 4 is very plausible, because both lines are available, and the load and local generation are close to their average value.

*D.3. Impact of Dependencies:* In order to assess the impact of dependencies, we have computed the probability of system states 1 to 4 assuming that all variables of the power system are independent (Table 2).

| System state | Probability |
|--------------|-------------|
| 1            | 0,048 %     |
| 2            | 1,035 %     |
| 3            | 1,464 %     |
| 4            | 2,547 %     |

Table 2: probabilities of 4 operating states (assuming independence)

The difference is clear, especially for state 1, whose probability is **over-estimated by 70**. Notice that the order of these probabilities remains unchanged, but the differences between the probabilities of two states are less important without taking the dependencies into account.

#### E. Conclusions

Bayesian Belief Networks proved to be helpful for the evaluation of power system state probability, because of their ability to model the uncertainties and dependencies of variables.

It allows the weighting of the decision tree by these probabilities to determine possible probabilistic operating rules.

In the near future, it is envisioned to use the BBN model of the power system in order to generate realistic samples of system operating states for security and adequacy studies.

#### IV. A validation and improvement of operating rules using a probabilistic approach

The method presented in part III was used to evaluate the probabilities of the 10,000 power system states with a **complete model** of the South Eastern part of France's power system (all the HV lines are represented: 110 nodes and 146 links). It has allowed the weighting of the decision tree by these probabilities to determine other possible operating rules that take the uncertainties into account and evaluate the accuracy of the statistical rules.

Table 3 shows the repartition of the probabilities of the 10,000 system states used in the determination of the operating rules, taking all the dependencies between availabilities of HV lines in the studied area into account.

| Range of probability | Number of states |
|----------------------|------------------|
| [1e-10, 1e-9[        | 178              |
| [1e-9, 1e-8[         | 21               |
| [1e-8, 1e-7[         | 369              |
| [1e-7, 1e-6[         | 530              |
| [1e-6, 1e-5[         | 406              |
| [1e-5, 1e-4[         | 2688             |
| [1e-4, 1e-3[         | 251              |
| [1e-3, 1e-2[         | 4993             |
| [1e-2, 1e-1[         | 564              |

Table 3: repartition of the probabilities of the 10,000 system states

The probabilities of the system states range from 1.04.10-10 to 2.08.10-2. The main conclusions of the calculation of probabilities were the following:

1. Taking stochastic dependencies into account is necessary (assuming independence would have yielded erroneous probabilities),
2. The computation of the probabilities using the BBN technique is fast (about 1 second per system state),
3. Some of the system states are very unlikely (probabilities of 10-10 to 10-9), mainly because of maintenance effects.

It is interesting to note that differences between probabilities of system states can be very wide, and that half of these system states have high probabilities. Most of these differences are due to the unavailability of HV lines in the area.

Then six new operating rules were generated using the decision tree method and taking the probabilities of the system states into account. This was the point of the probabilistic approach: in the first step of the study, the operating rules were determined without considering the probabilities of the system states, although some of the system states were obviously very unlikely. It was initially thought that, because of their presence, the probabilistic approach could yield very different operating rules.

As for the first approach, each operating rule is expressed in terms of comparison of bus voltage, reactive power generation and importation with thresholds and can be used in real-time to evaluate if the system state is acceptable or not (from the security point of view). The choice of the most appropriate rule depends on the operating strategy. For each operating rule, three probabilistic indicators were calculated:

- probability of serious failure, i.e. probability of evaluating as acceptable an unacceptable system state
- probability of false alarm, i.e. probability of evaluating as unacceptable an acceptable system state
- total probability of failure, i.e. probability of mis-evaluating a system state.

These indicators were also calculated for the rule determined in the first step of the study.

Depending on the relative costs allocated to false alarms and serious failures, the decision tree algorithm generates different rules. Six new "probabilistic" operating rules were obtained by modifying these costs (and also using different decision tree algorithms).

For example, allocating the same cost to false alarms and serious failures leads to a simple operating rule :

**RI-proba:** "The situation is acceptable whenever the voltage at bus Realtor is greater than 390 kV"

Allocating different costs to false alarms and serious failures can lead to a slightly more complicated operating rules, not only based on the voltage at bus Realtor but also on the reactive generation of the hydro power plants in the Durance valley, or the reactive import of the east area for example.

The figure below represents the probabilities of serious failure and the probabilities of false alarm for the rules of the first step of the study, for the present operating rule, and for the probabilistic rules. The indicators of the probabilistic rules are equivalent in terms of serious failure, and slightly better in terms of false alarms.

The actual rule is not located among the statistical ones (from which it is derived) because it has been decided to modify the thresholds in order to decrease the serious failure rate in its case.

The important point is that, in this figure, the present operating rule is located among the probabilistic rules. The probabilistic approach hence provides a validation of the rules of the first step of the study, and of the present operating rule.

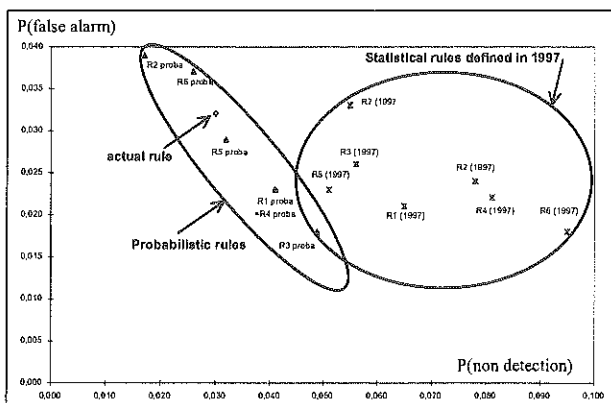


Figure 4: probabilities of serious failure and false alarm of the rules

In this particular study, taking probabilities into account did not lead to modification of the operating rules. A possible explanation of this fact is the following: an operating rule is used to identify the limit between acceptable and unacceptable system states (from the security point of view). It may be assumed that the very unlikely systems states are very far from this limit. Therefore, they do not influence the determination of the limit in this particular study, neither from the statistical approach, nor the probabilistic approach. If this assumption is correct, a smaller sample of systems could have yielded the same operating rules and saved computation time.

It may be observed that the Bayesian Belief Network technique can also be used for random generation of a sample of 'realistic' system states, taking the stochastic dependencies into account. The operating rules can then be determined taking only the operating states of high probability into account and the number of simulations to perform in such a study can be reduced by neglecting the situations of very low probability.

## V. Conclusion

The study of the voltage security of the South Eastern part of France's subsystem has shown the great interest of the statistical and probabilistic approaches to such problems. The ability to take a large number of different power system states and their probabilities into account allows one to assess the stability limits of the system very accurately. Moreover, the possibility of modeling uncertainties makes the criteria very robust. Bayesian Belief Networks proved to be helpful for the evaluation of a power system state probability, because of their ability to model the uncertainties and dependencies of variables. In the near future, use of the BBN model of the power system in order to generate realistic samples of system operating states for security and adequacy studies is planned.

## VI. References

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## Determination of Network Configuration and Generation Distribution under the N-1 Criterion

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**Abstract**—Network configuration and operation planning must be appropriate to maintain power system security. Distribution of generator power outputs is to minimize generation cost and to prevent power interruption under a one circuit contingency of double circuit lines.

For a large-scale network, the short circuit capacities are sometimes above the ratings of the short circuit breakers. The network configuration will be changed to reduce the short circuit capacity. However, determination of a network configuration must consider voltage stability as well as short circuit capacity.

To determine the generation distribution under the N-1 criterion, the conventional calculation method of distribution of generation to minimize generation cost is not practical, because all admittance matrices for the pre-specified line disturbances are necessary.

In this paper, an automatic determination procedure for network configuration and generation distribution under the N-1 criterion is proposed, which includes minimizing the affects of the voltage stability and to satisfy the capacity ratings of circuit breakers.

**Keywords**—Network Configuration, LP, OPF, N-1 Criterion

### I. INTRODUCTION

Regulation of power system utility has been changing widely. Engineers, who are experts of power system network field, must announce the necessary conditions to stably operate a power system to all participants in any competitive situation. Planning of network operations is more difficult and time for planning must be cut back in a deregulated environment. As well known, a power system is very large and complex. Engineers, who have extensive experience but do not have resources to apply information technology (IT) to power system analysis are not able to determine suitable operating conditions. To solve the above problem, new and more powerful computer aided calculation systems should be developed. Also, the keyword "transparency" of power system operation is very important for this kind of system.

This paper proposes one useful logical method to set up a network configuration and dispatch generator output under the N-1 criterion, where no outage will occur for a single contingency in a power system.

For a large-scale network, the short circuit capacities are sometimes above the ratings of the short circuit breakers. A simple logical method of determining a network configuration is not preferable because the performance of a power system depends heavily on the configuration, so that a network configuration candidate, which only considers magnitude of short circuit capacity, has the possibility of deteriorating voltage stability. Also, the formulation of a network configuration problem involves integer programming, because the state of the transmission line is expressed by the integers 0 or 1. An integer programming method is not preferable for a large-scale power system because calculation efforts may be unreliable.

On the other hand, determining the dispatch under the N-1 criterion has the following problem in calculation. A basic for-

mulation of the dispatch output of each generator under the N-1 criterion is necessary for power flow equations at all N-1 situations, so this formulation is not practical because the number of equality constraints of optimal power flow (OPF) is very large.

To solve the above numerical problem, this paper proposes the use of a linear programming (LP) method to screen out the transmission lines, which are able to disconnect to reduce short circuit current with less affect on voltage stability. Furthermore, feasibility verification of a network configuration candidate is discussed.

To reduce the equality constraints of the OPF of dispatch output of each generator under the N-1 criterion, this paper discusses the possibility of having OPF based on a new concept that employs an iteration scheme instead of a large number of equality constraints.

Arrangement of the rest of the paper is as follows. In section II, the outline for deciding on a proposed scheme is explained. In section III, a purpose for applying LP method to decide on a network configuration is proposed. To verifying feasibility of a network configuration is discussed in section IV. In section V, OPF under N-1 without expanding the number of constraints is presented. Conclusions are drawn in section VI.

### II. FLOWCHART OF PROPOSED METHOD

Figure 1 shows the outline of the proposed scheme in this paper.

- A network configuration candidate determines on or off status of the circuit breakers using a linear programming method. The objective function is to minimize loss of reactive power consumption, with line admittance as the variables. The constraints are the capacity ratings of the transmission lines and the quantities of the short circuit capacities. The voltage stability is intermediately considered by minimum reactive power loss.
- To verify whether the created network configuration candidate satisfies the N-1 criterion or not, for all pre-specified disturbances, an optimal power flow (OPF) program is used with weighting coefficients for line admittance as the variables and to minimize the weightings as the objective function. All disturbances satisfying N-1 criterion will be found. If the weighting coefficients can not be one, which means that network configuration is infeasible, then return to first process with reduced rating capacity of transmission line.
- To determine the generation distribution, iterative use of OPF is proposed, which involves applying sensitivity analysis and a DC flow method. Although this proposed procedure requires an iterative process, it is not necessary to prepare all admittance matrices for the pre-specified dis-

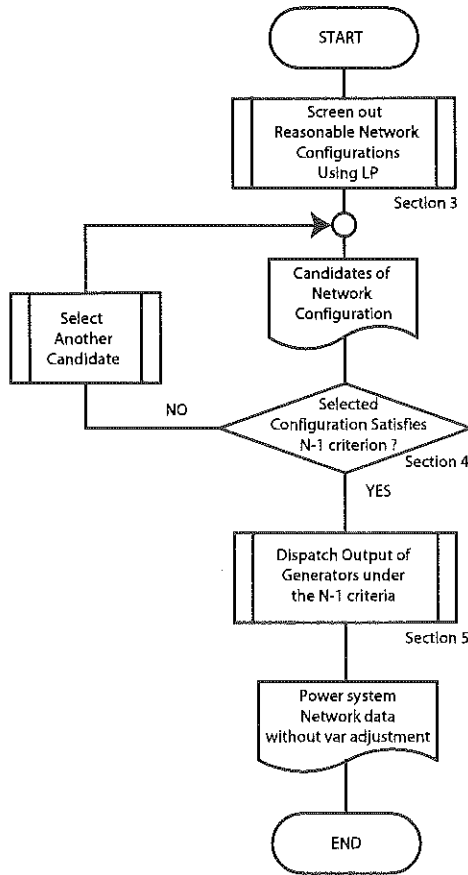


Fig. 1. Outline of Developing the Calculation System

turbances.

A network configuration and output of individual generators for each consideration time is solved as shown in the Figure 1 procedure. However, unit commitment of a power station should be taken into account when deciding the operation planning. The paper [3] discusses one useful scheme for using the AC-OPF results. Also, AC-OPF is necessary to evaluate network performance to achieve a spot price. An AC-OPF solving reactive power balance and transformer tap position will be necessary after this procedure. For this purpose, voltage stability is very important. We clarified the possibility to embed the voltage stability index into the inequality constraints of conventional AC-OPF [4].

### III. SCREEN OUT METHOD OF NETWORK CONFIGURATION USING LP

The performance of a power system network varies with the network configuration. Especially, voltage stability depends heavily on the network configuration. If the rating of circuit breakers cannot be extended from the viewpoint of economy, close attention should be given when determining the network configuration.

Generally, for reducing short circuit current, large transmission line impedance is preferable but affects voltage stability. An important transmission line for voltage stability does not

correspond to the transmission line passing a large fault current. Thus, coordinating the network configuration with respect to co-operating short circuit current and voltage stability is possible.

The paper [5] discusses minimizing short circuit capacity as transmission line impedance is treated by variables, in other words, [5] treat the value of the short circuit current as the objective function. In a practical situation, the short circuit current is preferably treated as constraints. Usually, variables like the operating state of a transmission line are expressed by integers (0 or 1). For the above reason, formulation to solve a network configuration involves integer programming without any heuristics. In the majority of cases, a power system operator and/or planner have needs screening out disconnectable transmission line candidates to instead to concrete network configuration.

This section discusses treating transmission line impedance as a continuous variable to screen out a disconnectable transmission line, for determining a network configuration. Some assumptions are made with the following issues,

- Voltage stability is best when all transmission lines in a network are connecting even though the short circuit current exceeds the rating of the circuit breaker.
- Dispatch of output power is fixed while deciding on a network configuration
- Power flow constraints are based on DC-flow calculations

#### A. Definition of Short Circuit Current Calculation

There are several short circuit current calculation methods. In this paper, a conventional method is used because the proposed method will be applied to operation planning, so that simple calculation is a more important issue than accuracy. In this paper, the below method is applied. The assumption in calculating short circuit current is as follows.

- The back-impedance of the generator is  $x_d'$ . Also,  $x_d''$  of generator is available.
- All loads, and shunt capacitor and reactor are neglected.
- Before the short circuit fault, the voltage of all buses in the network is maintained 1 [p.u]

Stands on the above assumption, short circuit current  $I_s^p$  at node  $p$  is calculated from Thevenin's theorem.

$$I_s^p = \frac{1}{z_{pp}^{<s>}} \quad (1)$$

where,  $z_{pp}^{<s>}$  is the element of the inverse matrix of  $Y_s$ , which is an admittance matrix with generator back-impedance.

#### B. Formulation of Network Configuration Problem for Non-Linear Programming

The objective function of minimizing reactive power loss is reasonable for indirectly considering voltage stability when deciding on a power system configuration. So, to determine suitable network configuration involves following a non-linear program formulation. The note of proposed method where transmission line impedance is treated as a variable regardless of transmission line impedance cannot be ordinary modified. Of course, the purpose of the proposed method is not to change with any transmission line impedance in calculating the results. The purpose of this method is to screen out the transmission

lines, which are preferable to de-energize from the viewpoint of suppressing the short circuit current.

$$\begin{aligned} \min \quad & Q_{loss}(\mathbf{G}, \boldsymbol{\delta}) \\ \text{s.t.} \quad & \end{aligned} \quad (2)$$

$$\mathbf{P} - \mathbf{Y}(\mathbf{G}) \cdot \boldsymbol{\delta} = 0 \quad (3)$$

$$P_{ij}(\mathbf{P}, \mathbf{G}) - R_{ij} \leq 0 \quad (4)$$

$$-P_{ij}(\mathbf{P}, \mathbf{G}) + R_{ij} \leq 0 \quad (5)$$

$$Z_{min} - z_{pp}^{<s>}(\mathbf{G}) \leq 0 \quad (6)$$

$$0 < \mathbf{G} \leq \mathbf{G}_{initial} \quad (7)$$

where,

$Q_{loss}$ : Reactive power losses ( $\sum_{i,j \in Line} (\delta_i - \delta_j)^2 G_{ij}$ )

$\mathbf{Y}$ : Admittance matrix for DC flow calculation

$\mathbf{P}$ : Injection Power vector

$\mathbf{G}$ : Transmission line Conductance vector

$\boldsymbol{\delta}$ : node voltage phase angle vector

$P_{ij}$ : Power Flow between node  $i$  and  $j$

$z_{pp}^{<s>}$ : A  $p, p$  element of inverse matrix  $\mathbf{Y}_s$

$Z_{min}$ : Allowable inverse value of of short circuit current

$R_{ij}$ : Rating of transmission line from node  $i$  to  $j$

This formulation allows calculation of optimal transmission line impedance that satisfies all constraints and minimizes reactive power loss. However, the value of the objective function and the value of the short circuit current as constraints move opposite when impedance of transmission line increases, so that iteration of calculation becomes large. On the other hand, optimal value of transmission line impedance is not necessary in determining the network configuration. Also, there are some factors in deciding on a network configuration besides the short circuit current constraint, for example, phase angle stability problem and/or security constraints, so that the method to screen out some configuration candidates is very useful.

### C. Modified Formulation for Linear Programming

The above characteristics of non-linear programming formulation is not preferable in determining a network configuration. This paper proposes the use of linear programming (LP) to screen out any transmission lines, which should be de-energized to safely reduce short circuit current.

$$\begin{aligned} \min \quad & \Delta Q_{loss} = \sum_{i,j \in Line} ((\delta_{i0} - \delta_{j0})^2 \Delta G_{ij} \\ & + 2(\delta_{i0} - \delta_{j0}) G_{ij0} \Delta \delta_i - 2(\delta_{i0} - \delta_{j0}) G_{ij0} \Delta \delta_j) \end{aligned} \quad (8)$$

s.t.

$$\Delta \mathbf{G} + \mathbf{Y} \Delta \boldsymbol{\delta} = 0 \quad (9)$$

$$P_{ki0} + \Delta P_{ki} < R_{ki} \quad (10)$$

$$P_{ki0} + \Delta P_{ki} > -R_{ki} \quad (11)$$

$$Z_{min} < z_{pp0}^{<s>} + \sum_{i,j \in Line} (z_{pi}^{<s>} - z_{pj}^{<s>})^2 \Delta G_{ij} \quad (12)$$

where,

$$\Delta P_{ki} = \sum_{p,q \in Line} \left\{ \frac{G_{ki0}}{G_{pq0}} (z_{kp}^{<l>} + z_{iq}^{<l>} - z_{kq}^{<l>} - z_{ip}^{<l>}) \right\} \Delta G_{pq} + \frac{P_{ki0}}{Y_{ki0}} \Delta G_{ki} \quad (13)$$

$z_{ij}^{<s>}$  is a  $i, j$  element of inverse matrix of  $\mathbf{Y}_s$

$z_{ij}^{<l>}$  is a  $i, j$  element of inverse matrix of  $\mathbf{Y}$

$Line$ : A set of node numbers at both ends of the transmission lines

subscript 0 means initial value

The variation of impedance value is obtained from the results of the above LP problem. However, the variation of impedance value is not important from before discussion clearly. The system described in figure 1 screens out a few transmission lines having a non-zero variation value. The system should select the most preferable transmission lines from the candidates using feasibility check routine at detail discussing section IV step by step.

A few example cases are applied to the proposed methods. The selected transmission line by the proposed method have common characteristics, for example, the power flow of the selected line is little, but the passing short circuit current is large. This characteristic is reasonable for deciding on a network configuration.

The proposed method requires some pre-processing, for example, the transmission line, which is not a component of the loop circuit, should not be considered with as variable impedance model to neglect wasteful calculation.

## IV. FEASIBILITY CHECK FOR N-1 CONTINGENCY

### A. Parameterized Contingency Constrained Optimal Power Flow (PCCOPF)

When the constraints, which guarantee the existence of power flow solutions for post contingencies, are incorporated into the formulation of OPF, the OPF might make control adjustments to the base or pre-contingency operation to prevent violations in the post contingency conditions. However, in the case of no feasible solutions for post contingencies, it is difficult for the OPF, which does not allow for convergence onto infeasible solutions, to analyze a feasible solutions considering contingencies.

Consequently, we propose a method for Parameterized Contingency Constrained Optimal Power Flow (PCCOPF) whose formulation can discriminate unpreventable contingencies, determine the existence of feasible solutions for post contingencies and analyze the feasible solution for the contingencies in terms of static sense. The proposed formulation is based on parameterized contingency constraints, in which each contingency parameter represents the achievement ratio of each selected contingency.

In the formulation, not only parameterized contingency constraints are given by a set of equality constraints, which is modified power flow equations, but also the objective is maximization of the sum of the achievement ratios of selected contingencies. Since contingency parameters are treated as decision variables

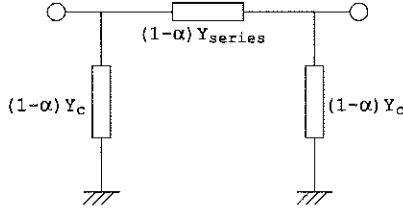


Fig. 2. The definition of contingency parameter for branch.

in the proposed method, information on unsolvability with respect to each contingency can be efficiently obtained.

### B. Parameterized Contingency Constraints

In general, power flow equations can be represented as follows.

$$F(x, u) = z \quad (14)$$

where  $x$  is a set of voltage vectors consisting of voltage magnitudes and angles.  $u$  is a vector of control variables involving the admittance matrix of a power system, such as shunt capacitors/reactors and transformer tap ratios.  $z$  is a vector of variables consisting of active and reactive powers of generators and loads.

In addition to parameterized contingencies, the load variation scenario can be parameterized with a scalar parameter  $\lambda$ , so that each load is treated as a control variable representing load shedding. To be concrete, it is defined that the total load  $P$  in an operating condition increases from the initial total load  $P_0$  according to  $P = (1 + \lambda)P_0$ , given the pattern of load variation at each load bus.

The total load is mathematically represented by a function with respect to the parameter  $\lambda$ , so that  $z$  can be rewritten as follows.

$$z = z(\lambda) \quad (15)$$

Then, (14) can be rewritten as follows.

$$F(x, u) - z(\lambda) = 0 \quad (16)$$

Now, let's discuss parameterized contingency concerning branch disconnection and generator/load drop-out in order to allow for convergence onto infeasible solutions and to analyze the feasible solutions for contingencies.

First of all, a parameterized contingency of branch disconnection is discussed. A vector of contingency parameters  $\alpha$ , which represents the achievement ratios of branch disconnections, is defined. The admittance of each branch can vary continuously according to a corresponding element  $\alpha$  of vector  $\alpha$ . If  $\alpha = 0$ , the branch is connected, and if  $\alpha = 1$ , the branch is completely disconnected (please see Fig. 2).

The power flow equations (16) can be rewritten as a function of the branch disconnection ratios  $\alpha$ .

$$F(x, u) - \alpha G(x, u) - z(\lambda) = 0 \quad (17)$$

where  $F(x, u)$  is a set of functions with respect to the injected powers at busses under a normal operating condition, which is derived from the admittance matrix of the power system, the

set of voltage vectors  $x$  and the vector of control variables  $u$ .  $\alpha G(x, u)$  represents the variation of injected powers at busses, where admittance matrix is varied according to  $\alpha$  representing the state of branch disconnections.

Next, a parameterized contingency of generator/load drop-out is discussed. As well as the case of branch disconnection, a contingency parameter vector  $\alpha$ , which represents the achievement ratios of generator/load drop-outs, is defined. The active and reactive powers at each generator/load bus selected as a contingency can vary continuously according to a corresponding element  $\alpha$  of vector  $\alpha$ . If  $\alpha = 0$ , the generator/load is under a normal condition, and if  $\alpha = 1$ , the generator/load is completely dropped out.

The active and reactive powers at generator busses vary depending on the amount the rated capacities of generators decrease in proportion to the value of  $\alpha$ . The generator drop-out contingency can be parameterized as follows.

$$\left. \begin{aligned} p &= (1 - \alpha)p_n, & p_n^{\min} &\leq p_n \leq p_n^{\max} \\ q &= (1 - \alpha)q_n, & q_n^{\min} &\leq q_n \leq q_n^{\max} \end{aligned} \right\} \quad (18)$$

where  $p$  and  $q$  are active and reactive power vectors at generator busses under consideration, respectively.  $p_n$  and  $q_n$ , which vary within the limits of the rated capacities, are active and reactive power generation vectors at generator busses under a normal operating condition, respectively.

In the case of load busses, active and reactive powers vary depending on the amount the active and reactive power loads under a normal operating condition decrease in proportion to the value of  $\alpha$ . In addition, the parameterized load variation scenario is also considered, so as to treat each load as a control variable representing load shedding. The load drop-out contingency can be parameterized as follows.

$$\left. \begin{aligned} p &= (1 - \alpha)(1 + d_p \lambda)p_s \\ q &= (1 - \alpha)(1 + d_q \lambda)q_s \\ \lambda_{\min} &\leq \lambda \leq 0 \end{aligned} \right\} \quad (19)$$

where  $d_p$  and  $d_q$  are vectors of the patterns of active and reactive load variations, respectively.  $\lambda_{\min}$  represents the acceptable level of load shedding. The limit of load variation parameter  $\lambda$  without load shedding is  $\lambda_{\min} = 0$  i.e.  $\lambda = 0$ .

Using (18) and (19), power flow equations (16) can be rewritten as a function with respect to  $\alpha$ .

$$F(x, u) + \alpha z(\lambda) - z(\lambda) = 0 \quad (20)$$

where  $\alpha$  is a vector representing the achievement ratios of generator/load drop-out.  $\alpha z(\lambda)$  represents the variation of injected active and reactive powers at busses corresponding to the achievement ratios of generator/load drop-out  $\alpha$ .

Using (17) and (20), power flow equations in which contingencies of branch disconnection and generator/load drop-out can be parameterized are rewritten as follows.

$$F(x, u) - \alpha G(x, u) + \alpha z(\lambda) - z(\lambda) = 0 \quad (21)$$

Once modified power flow equations (21) are incorporated into the OPF formulation as equality constraints, and contingency parameter vector  $\alpha$  is treated as control variables, the information on unsolvability with respect to contingencies can be obtained as the result of the OPF.



Since the number of equations (21) is the same as the general power flow equations and the number of constraints in the OPF formulation does not increase, stable convergence of the OPF can be expected.

### C. Formulation of PCCOPF

Using (21), Parameterized Contingency Constrained Optimal Power Flow (PCCOPF) can be formulated as follows.

$$\max_{x,u,\lambda,\alpha} f(x,u,\lambda,\alpha) = \sum_k \alpha \quad (22)$$

subject to

$$g_1(x,u,\lambda,\alpha) = F(x,u) - \alpha G(x,u) + \alpha z(\lambda) - z(\lambda) = 0 \quad (23)$$

$$g_2(x,u,\lambda,\alpha) = 0 \quad (24)$$

$$h(x,u,\lambda,\alpha) \leq 0 \quad (25)$$

where the objective function (22) is the maximization of the sum of the contingency parameter values. In the case of  $(N-1)$  contingency, the number of contingencies is  $k=1$ . In the case of multiple contingencies more than  $(N-2)$ , the number of contingencies is  $k \geq 2$ . (23) is a set of power flow equations modified by contingency parameter vector  $\alpha$ . (24) is a set of equality constraints concerning power equipment/controllers and system stability. (25) is a set of inequality constraints concerning all variables and power flows. The constraint of the load variation scenario  $\lambda$  is set up as (19).

The bound pair of  $\alpha$  is;

$$\begin{aligned} 0 \leq \alpha \leq 1 & \quad \text{if contingency branch/busses} \\ \alpha = 0 & \quad \text{otherwise.} \end{aligned}$$

When PCCOPF determines  $\alpha = 1$  ( $\sum_k \alpha = k$ ) in which contingencies can be realized, there is a feasible solution for post contingencies. On the other hand, when PCCOPF determines  $\alpha < 1$  ( $\sum_k \alpha < k$ ) in which contingencies cannot be realized, there is not feasible solutions for post contingencies under a power system configuration and generator/load capability.

### D. Use of PCCOPF

PCCOPF can be used for a power system security analysis. Applications of PCCOPF to the security analysis study are summarized as follows.

#### D.1 Feasibility check for contingencies

In terms of static sense, PCCOPF can discriminate unpreventable contingencies, and determine the existence of feasible solutions for post contingencies under a power system configuration and generator/load capability. However, it is unrealistic that PCCOPF is applied to all possible contingencies. In general, PCCOPF is applied to appropriate contingencies that are filtered out in terms of system security such as voltage stability and transient stability.

The algorithm for checking for the feasibility on  $(N-1)$  contingency can be summarized as follows.

**Step 1:** Make a  $(N-1)$  contingency list for a power system.

**Step 2:** Select a  $(N-1)$  contingency.

**Step 3:** Check for feasibility on the  $(N-1)$  contingency by PCCOPF. If PCCOPF determines  $\alpha = 1$ , there is a feasible solution for the post contingency. Otherwise, there is not feasible solutions for the post contingency under the power system configuration and generator/load capability.

**Step 4:** If all  $(N-1)$  contingencies are checked out, terminate the algorithm. Otherwise, go to Step 2.

#### D.2 Analysis for obtaining feasible solutions

According to Karush-Kuhn-Tucher conditions, Lagrange multipliers computed by PCCOPF can explain the sensitivity of the objective function with respect to the constraints. In other words, the Lagrange multipliers computed by PCCOPF are efficient information to improve the value of the objective function and obtain a feasible solution for post contingencies by means of the relaxation of constraints concerning some kind of countermeasures.

According to the Lagrange multipliers explanation, each objective function value, when each countermeasure candidate is done, can be estimated by using the following equation.

$$\alpha_e = \sum_k \alpha^* + \pi u_s \quad (26)$$

where  $\alpha^*$  is a vector of the contingency parameters, which is computed by a PCCOPF without the countermeasure candidates.  $\pi$  is a vector of the Lagrange multipliers of constraints concerning the countermeasure candidates.  $u_s$  is a vector of the values of the countermeasure candidates.

Using the information (26), we can efficiently analyze and obtain a feasible solution for post contingencies in terms of static sense.

## V. OPTIMIZING DISTRIBUTION OF GENERATION UNDER N-1 CRITERION

### A. fundamentals of optimization

Optimizing distribution of generation, which satisfies line capacity constraints, is defined as follows. (DC-flow is used in this formulation.)

$$\text{Objective: } \min_{P_G} \sum_k f(P_{Gk}) \quad (27)$$

$$\text{subject to: } g_1 = Z\delta, \quad -R \leq g_1 \leq R \quad (28)$$

(constraint of maximum flow)

$$g_2 = Y\delta - P, \quad g_2 = 0 \quad (29)$$

(flow equation)

$k$  :  $k \in K$ : generators of a system

$P_{Gk}$  : generation at node  $k$

$f(P_{Gk})$  : generation cost for  $k$

$R$  : vector of rating for each line

where  $g_1$  means a vector of flow on transmission lines, and  $Z$  is a sparse matrix derived from DC-flow approximation:

$$P_{k\ell} \approx \frac{\delta_k - \delta_\ell}{X_{k\ell}} \quad (30)$$

Constraints matrix is represented as:

$$\begin{bmatrix} g_1 \\ g_2 \end{bmatrix} = \begin{bmatrix} 0 & Z \\ -I & Y \end{bmatrix} \begin{bmatrix} P \\ \delta \end{bmatrix} \quad (31)$$

The solution is optimal only for one network configuration.

To consider N-1 contingency on a transmission line in optimization, multiple configurations raised from the contingencies must be counted.

In a primitive method to optimize under the N-1 criterion, matrix  $Y$  and  $Z$  are fixed for each network configuration respectively. ( $Y^{<b>}$ ,  $Z^{<b>}$ : for contingency on line  $b$ ) Then  $\delta^{<b>}$  is determined by using  $g_2^{<b>}$ , and line constraints  $g_1^{<b>}$  is checked. Constraint  $g_2^{<b>}$  is used to determine  $\delta^{<b>}$ .

TABLE I  
PARAMETERS FOR PRIMITIVE METHOD

| status               | parameters |           |                | constraints            |
|----------------------|------------|-----------|----------------|------------------------|
| initial condition    | $Y^{<0>}$  | $Z^{<0>}$ | $\delta^{<0>}$ | $g_1^{<0>}, g_2^{<0>}$ |
| contingency line 1   | $Y^{<1>}$  | $Z^{<1>}$ | $\delta^{<1>}$ | $g_1^{<1>}, g_2^{<1>}$ |
| contingency line 2   | $Y^{<2>}$  | $Z^{<2>}$ | $\delta^{<2>}$ | $g_1^{<2>}, g_2^{<2>}$ |
| $\vdots$             | $\vdots$   | $\vdots$  | $\vdots$       | $\vdots$               |
| contingency line $B$ | $Y^{<B>}$  | $Z^{<B>}$ | $\delta^{<B>}$ | $g_1^{<B>}, g_2^{<B>}$ |

( $B$ : number of looped branches)

Constraints matrix is:

$$\begin{bmatrix} g_1^{<1>} \\ g_2^{<1>} \\ g_1^{<2>} \\ g_2^{<2>} \\ \vdots \\ g_1^{<B>} \\ g_2^{<B>} \end{bmatrix} = \begin{bmatrix} 0 & Z^{<1>} & 0 & \dots & 0 \\ -I & Y^{<1>} & 0 & \dots & 0 \\ 0 & 0 & Z^{<2>} & \dots & 0 \\ -I & 0 & Y^{<2>} & \dots & 0 \\ \vdots & \vdots & \vdots & \ddots & \vdots \\ 0 & 0 & 0 & \dots & Z^{<B>} \\ -I & 0 & 0 & \dots & Y^{<B>} \end{bmatrix} \begin{bmatrix} P \\ \delta^{<1>} \\ \delta^{<2>} \\ \vdots \\ \delta^{<B>} \end{bmatrix} \quad (32)$$

In this way, the matrix may grow to huge size as the network becomes complicated. In addition, the number of variables is multiplied by the number of N-1 conditions. These are undesirable attributes for computer calculation.

#### B. iterative method to reduce constraints

At this point, the line flow with a contingency is calculated as a superposition of the initial condition flow and deviation by the outage. And the deviation is a superposition of flow by each injection.

Power flow in  $b$  th contingency can be written:

$$\begin{aligned} P_{kl}^{<b>} &= P_{kl}^{<0>} + \Delta P_{kl}^{<b>} \\ &= P_{kl}^{<0>} + \sum_{n \in N} C_{kl}^{<b>,n} P_n \end{aligned} \quad (33)$$

$N$ : number of injection nodes

Where  $C_{kl}^{<b>,n}$  is line  $kl$  flow sensitivity to injection  $n$  in  $b$  th line contingency, which is derived from a compensation theorem.

(33) yields a vector of constraints without using  $\delta^{<b>}$  ( $b \neq 0$ ):

$$\begin{aligned} g_1^{<b>} &= (Z^{<b>} \delta^{<b>}) = \begin{bmatrix} \vdots \\ P_{kl}^{<b>} \\ \vdots \end{bmatrix} \\ &= g_1^{<0>} + \begin{bmatrix} \vdots \\ C_{kl}^{<b>,1} & C_{kl}^{<b>,2} & \dots & C_{kl}^{<b>,N} \\ \vdots \end{bmatrix} \begin{bmatrix} P_1 \\ P_2 \\ \vdots \\ P_N \end{bmatrix} \\ &= Z^{<0>} \delta^{<0>} + C^{<b>} P \\ &= \begin{bmatrix} C^{<b>} & Z^{<0>} \end{bmatrix} \begin{bmatrix} P \\ \delta^{<0>} \end{bmatrix} \end{aligned} \quad (34)$$

By excluding  $\delta^{<b>}$ ,  $g_2^{<b>}$  ( $b \neq 0$ ) becomes unnecessary.

Consequently, constraints for all N-1 contingencies are:

$$\begin{bmatrix} g_1^{<1>} \\ g_1^{<2>} \\ \vdots \\ g_1^{<B>} \\ g_2^{<0>} \end{bmatrix} = \begin{bmatrix} C^{<1>} & Z^{<0>} \\ C^{<2>} & Z^{<0>} \\ \vdots & \vdots \\ C^{<B>} & Z^{<0>} \\ -I & Y^{<0>} \end{bmatrix} \begin{bmatrix} P \\ \delta^{<0>} \end{bmatrix} \quad (35)$$

In this formulation, the number of variables is not increased regardless of any N-1 condition, and recalculation for  $Y, Z$  is not needed, even though the matrix size is still rather large. Applying matrix  $C$ , we can reduce the number of variables in the programming problem.

Previously,  $C^{<b>}$  is defined as a sensitivity of line flow to the outage of line  $b$ . In practical terms, each line has some specific lines extremely affecting its flow. In this paper, we call them sensitive lines. In general, there are many lines which have little sensitivity to some lines, so that we can ignore them when optimizing.

On the assumption that we can prefigure the power flow distribution, and that power flow of each line can be over its limit only by the outage of the maximum sensitive line, it is sufficient to consider sensitivity to the maximum sensitive line for each constrained line. Constraints matrix come to:

$$\begin{bmatrix} g_1^{<max>} \\ g_2^{<0>} \end{bmatrix} = \begin{bmatrix} C^{<max>} & Z^{<0>} \\ -I & Y^{<0>} \end{bmatrix} \begin{bmatrix} P \\ \delta^{<0>} \end{bmatrix} \quad (36)$$

It seems extremely simpler than the forenamed formulas. But note that the above assumption may not be true in some cases (for instance the system is heavy loading). On such an occasion, the constraint matrix must be expanded because the sensitivities to multiple lines should be considered simultaneously in optimization. As such the matrix is:

$$\begin{bmatrix} g_1^{<1>} \\ g_1^{<2>} \\ \vdots \\ g_1^{<B'>} \\ g_2^{<0>} \end{bmatrix} = \begin{bmatrix} C^{<1>} & Z^{<0>} \\ C^{<2>} & Z^{<0>} \\ \vdots & \vdots \\ C^{<B'>} & Z^{<0>} \\ -I & Y^{<0>} \end{bmatrix} \begin{bmatrix} P \\ \delta^{<0>} \end{bmatrix} \quad (37)$$

$B'$ : number of sensitive branches ( $B' \ll B$ )

In this term, the matrix includes sensitivities to multiple sensitive lines. To build it, we should check sensitivities to all lines, and make a list of the sensitive lines for each constrained line. Then, fill in the matrix. In a large looped system, the sensitive lines for each constrained line are minor. In our study, it is less than 10% of all lines. More specifically, a large number of insignificant constraints are screened out with ease by applying sensitivity. The constraint matrix can be efficiently contracted by this means.

As described above, to solve problem (27) subject to (37), the optimal distribution of generation is obtained. In this solution, a few iteration is needed, because the list of sensitive lines can change according to the variation of the initial flow distribution (Fig. 3). However, the contracted matrix and small number of variables make total calculation time very brief.

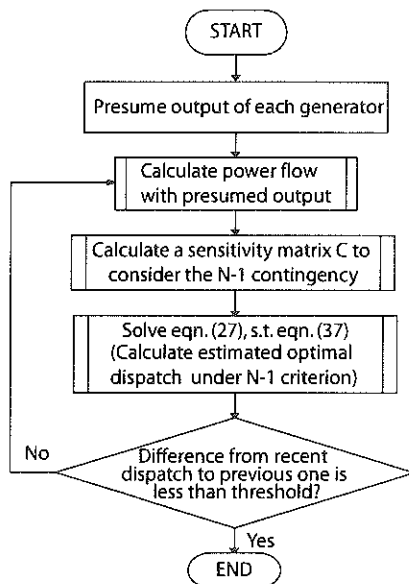


Fig. 3. N-1 optimization process

## VI. CONCLUSIONS

In this paper, useful calculation methods for a network configuration and dispatch under the N-1 condition are discussed.

The basic idea of the proposed method combines several OPFs having various effective objective function instead of one multi-function OPF. The proposed method has a disadvantage that the possibility of finding the global optimal state is less than in a single multi-function OPF. However, the proposed method is useful and flexible.

The future task of this project is follows,

- Evaluation of the numerical example using a large-scale power system
- Apply the function of calculating nodal price and/or wheeling rates [2] based on AC-OPF
- Combine the evaluation of the power system security routine and the proposed scheme

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## Discussions on Session V: OPERATIONS PLANNING

### Part 1

**Chairman** (S. Iwamoto): It's now 10 o'clock so we have plenty of time for discussion. We'll start the discussion.

**V. Ajjarapu** (Iowa State University): This is for EDF. How do you measure the risk with respect to voltage collapse? Are they measuring dollars if something happens? It's not clear.

**J. Pompee**: For each system state, we simulate some contingencies, the loss of the lines or generating units. After that, we simulate the load increase. There is a risk of voltage collapse when this margin is under 200 megawatts. We can imagine that there is a voltage collapse when this margin is 0 or negative.

**S. Corsi** (CESI): What I understood is the use of the contingency selection model and security constrained optimization model operated in a preventive way, kind of the most secure operating condition. What is not clear to me is the dynamics of your work. Do you understand which way your solution operated during voltage transients, operate in real time, or wait till this stable operating condition and then optimize the new operating condition?

**R. Schluether**: Our method could work either in the preventive method, where like in the other papers here, we would try to prevent all equipment simultaneously. It should be noted that each of the critical agents has reactive reserve constraints, and therefore, if you violate any one of them, you don't have a feasible starting solution. That is an important thing. So we have to get the step to find out if we do have a feasible solution. If you're going to implement in a corrected manner, you got to pre-compute this control off line. Start them, and look, and monitor your relay setting, or your state estimator, or whichever you're looking at operating condition changes, or equivalent outages. When it happens, you have 2 to 5 minutes to look at when you correct the problems. The second part of your question was transient voltage stability. Our technique would not typically look at transient voltage stability in the system-wide collapse. I would think about what you've seen this week, the wide area protection schemes. That would be more suitable for that.

**J. K. Park** (Seoul National University) I have a question to TEPCO's people. In the real operation of your TEPCO system, do you really disconnect to reduce the fault current?

**T. Takazawa**: Yes, we do. The TEPCO power system is

a very large looped system. The short circuit current is nearly 63 kA, near the rating of circuit breakers.

**J. K. Park**: Don't you have another measure to reduce the fault current at the operation plants, like bus separation?

**T. Takazawa**: Maybe bus separation is an option.

**J. K. Park**: Then, do you have any counter measures at the scheduled planning, like adopting some FACTS devices to reduce the fault current at the stage of planning, I mean, the transmission planning?

**Chairman**: Probably you can consider FACTS devices also for your planning, in addition to your proposed method.

**J. K. Park**: And another counter measure, at the stage of planning, not operation planning.

**T. Takazawa**: To the best of my knowledge, we didn't consider that.

**T. Van Cutsem** (University of Liege): I have a question for Mr. Pompee. In the second method, where you use the BBN technique and NETICA software, what is your input data? Do you collect on line data statistically?

**J. Pompee**: We have worked a lot with the European people, like in the Riviera area, and it could be very simple, when it's one degree or colder, or there is 250 megawatt more load. We have used operation feedback but generally there are very few data that is available. The problem of data is the most important problem here. We try to organize with the French ISO, some working groups, and some organization to collect a great amount of data.

**C. Canizares** (University of Waterloo): This question is for Mr. Pompee. I'm just curious if you could shed some light on this number you mentioned of the 250 megawatts, which is the one you use for determining acceptable or unacceptable? What is the condition of your system?

**J. Pompee**: This 250 megawatts corresponds to an increase of, I think, 15 minutes in the area in the peak conditions in the peak morning of the day. The operator decided that this threshold limit is acceptable or unacceptable state. They consider that if the margin is under this 250 megawatts, they will not have the possibility to take a remedial action. They consider that

if they have a less 250 margin, they could have a big problem. So that's why we have this 250 megawatts threshold in our study.

**Chairman** (S. Iwamoto): Thank you. Any other comments or questions? I have myself some questions. The first one is for Dr. Pompee. My question is how you take into account the configuration change?

**J. Pompee:** In fact, the configuration change could occur everyday in operation. These are represented with very huge numbers of system states. We consider ten thousand system states with random network topology or load. But I can say that this advantage of such a strategy is that when, for example, a new line is built or new generator unit is built, we have to perform again the entire study. So that's why I said that we will do this kind of strategy maybe every two years or three. That's why we have developed a number of tools.

**Chairman:** I see. Thank you. Any other questions or comments? I have another question about Professor Schlueter's approach. I just want to raise the issue that in this deregulated environment, you mention the preventive control, and also mention the tripping the generators and loads. Probably in the real situation, the system operator would not trip load when the system is stable for the preventive scenario. Are there measures for the system operators to not be sued by the generator companies or customers? I don't know the actual scenario in the deregulated society. How are you prepared against being sued, because you're going to trip generation or loads?

**R. Schlueter:** Our technique can be done preventively, which means you take action ahead of time, or correctly. In a corrective action, you're postponing any shedding or generation shedding until the very last minute. All you've got is 2 to 5 minutes to do whatever you pre-computed. In thermal and voltage problems, it prevents quite significant numbers of constraints, constraints of feasible region, increasing the cost to the company and the users. We don't believe that's the way to implement the strategy. Yes, you could wait until the last minute in a preventive action, and take all the actions that, you know you can still detect the problems. You could still take actions. We accomplish most of some of the objectives and maybe more of them preventing more than what you look at, or just preventing what you've got. But our view is corrective action, where you tailor controls exactly to the equipment outage, it gives you an incredible power for correcting that.

**Chairman:** Ok, any other information? I heard in some countries, there is a regulation that the power company has to keep the N-1 criteria.

**R. Schlueter:** One additional comment here. If you're looking at the correct control or preventive control,

when you're actually looking and facing down at both coming actions, you're absolutely at the point of collapse, then corrective action or preventive action is an absolutely warrant, you do that by your protective relay. So in fact if we take in a corrective actions in that case, this is no different than what you would do in a preventive, relaying action.

**J. K. Park:** In Korea, after the deregulation this year in April, there are many disputes from the customers and among the generators. But the most important is to record, recording of everything. After that, we hear everything just by experts finally. But rules can not solve everything, after recording and hearing. It's very important.

## An Inclusion of Security Constraints with Distributed Optimal Power Flow

|                                                                                                                                                                                                                     |                         |                                                                                                                                                                                  |                                                                                                                                                                                                            |                          |
|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|-------------------------|----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|--------------------------|
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### Introduction

Today's utility executive must be confronted by a spectrum of technical issues, ranging from wheeling and transmission line access to loop flow. There are other challenges to face. The traditional utility corporate structure is being reorganized, with utility staffs shrinking in size. Furthermore, public scrutiny has become more intense as public bodies question the technical and environmental impact, as well as the financial and legal prudence of a utility's activities.

Utilities are successfully meeting these challenges and becoming more productive, due, in part, to their use of innovative computer programs and tools. One of these tools is an optimal power flow (OPF). The following describes a new dimension in the optimal power flow technology known as the security constrained optimal power flow (SCOPF) [1], [2].

A key requirement of any modern society is the economic secure operation of its electric power system. Such an important objective naturally requires the use of advanced large system analysis, optimization, and control technology. Recently, this technology is being incorporated into the economy-security functions of the utility-company Energy Management System (EMS). The relevant security analysis and optimization is the subject of this paper.

The security constrained optimal control of an electric power system generation-transmission network is an extremely difficult task. This difficulty tends to increase with growth in system size [3], interconnection, and other operating problems. The same is true regarding other planning and operation problems that require the solution of security constrained optimal power flows as a pre-requisite [4].

During the last few years the requirement for faster and more frequent solutions has encouraged an exponential growth in networked computing resources. The old paradigm of a single computer serving a whole organization is being replaced by a large number of separate, but interconnected autonomous computers. The growth of computer networks has been accompanied by an increase of individual computational power.

As the use of networks close to their ultimate ratings led to a fear of line overloading, the incorporation of several security constraints into the context of optimal power flow is becoming an important tool to determine the system state under considerations of load and operating constraints. The objective of security constrained optimal power flow is to determine a minimum cost operating point where the system is kept in a normal state after a major disturbance such as transmission line and/or generator outage [5].

In SCOPF, the system operating constraints under various configurations are added to the normal OPF problem to impose additional limits on line flows and bus voltages for the post-disturbance configurations resulting from a given set of contingencies. That is, for each contingency considered, the post-contingency variables, power flow, and operating constraints are appended to the basic pre-contingency OPF formulation to represent the contingency condition. In general, the appended constraints depend on both the pre- and post-contingency variables; however, an approach based on the linearization of a pre-contingency base-case can simplify the representation of the constraints.

To incorporate contingency constraints, we will use a linear programming approach that iterates between solution of a base-case and calculation of post-contingency states [2], [3], [6], [7], [8]. In each iteration, a pre-contingency base-case OPF is first solved. For each contingency, the post-contingency state is determined based on the solution to base-case. The post-contingency constraints are then linearized in terms of the solution to the base-case. The linearized contingency constraints are appended to the base-case OPF. In each subsequent iteration, the base-case OPF incorporates the linearized contingency constraints from the previous iteration.

In the distributed OPF scheme [9], [10], contingency constraints are not easily expressed in terms of the core and border variables for each region, and because of regional decomposition and  $\lambda$  updates at the border, the conventional linear programming approach may not be applied directly.

This paper is organized in five sections. In Section II, we first specify the attributes of optimal power flow, and then set forth a mathematical formulation of SCOPF. In Section III, details on the problem formulation and practical implementation of the distributed security constrained optimal power flow algorithm will be given, followed by a short description on the inclusion of security constraints into our distributed OPF scheme. In the fourth Section, Korea Electric Power System is used to investigate ways to represent security constraints and to solve the SCOPF efficiently and reliably in a distributed manner. Finally, in Section V, a discussion on the distributed security constrained optimal power flow issues is given first. Then a future research direction pertinent to the presented work is given.

### Overview of SCOPF

The OPF problem was defined in the early 1960's as an extension of conventional economic dispatch to determine the optimal settings for control variables in a power network respecting various constraints. OPF is a static constrained nonlinear optimization problem, whose development has followed closely advances in numerical optimization techniques and computer technology.

OPF requires solving a set of nonlinear equations, describing optimal and/or secure operation of a power system, expressed as [11]:

$$\min_Z f(Z) \quad (1)$$

$$\begin{aligned} \text{s.t. } G(Z) &= 0 \\ H(Z) &\leq 0 \end{aligned} \quad (2)$$

where,

- $Z \in \mathcal{R}^{m+n}$  is the vector of decision variables that include both control and state variables. That is,  $Z = [U \ X]^T$  where,  $U \in \mathcal{R}^m$  is the vector of control (independent) variables, and  $X \in \mathcal{R}^n$  is the vector of state (dependent) variables. Examples of control variables are the real power output of generators, voltage magnitudes at generator buses, and transformer taps. The state variables include the voltage magnitudes and voltage angles at the load buses in the system.
- $f: \mathcal{R}^{m+n} \rightarrow \mathcal{R}^1$  is the objective function representing operating costs (e.g., the generator fuel costs).
- $G: \mathcal{R}^{m+n} \rightarrow \mathcal{R}^a$  is the vector function representing the load flow constraints (i.e., the power balance constraints).
- $H: \mathcal{R}^{m+n} \rightarrow \mathcal{R}^b$  is the vector function representing operating constraints such as limits on line flows or bus voltages.

In this paper, we extend the formulation (1)-(2) by adding, in turn, security constraints to obtain a security constrained optimal power flow. The optimal power flow with security constraints is aimed at determining a feasible, minimum cost (or minimum deviation) operating point, such that in the event

of a contingency out of a given list, the post-contingency state will remain safe (feasible). The SCOPF (preventive mode) was originally suggested in [1] and extensions for dealing with post-contingency rescheduling capabilities (corrective mode) were suggested in [7] and studied in [3]. The traditional notion of security has relied almost exclusively on preventive control. That is, the requirement has been that the current operating point be feasible in the event of the occurrence of a given subset of the set of all possible contingencies. In other words, the base-case control variables are adjusted to satisfy post-contingency constraints which are added to (1)-(2). For simplicity only preventive mode SCOPF will be described in the following:

$$\min_{U_0, X_i} f(Z_0) \quad (3)$$

$$\begin{aligned} \text{s.t. } G_i(U_0, X_i) &= 0, \quad i = 0, 1, 2, \dots, N \\ H_i(U_0, X_i) &\leq 0, \quad i = 0, 1, 2, \dots, N \end{aligned} \quad (4)$$

where,

- $i = 0$  is the base case, and  $i > 0$  represents the  $i^{\text{th}}$  post-contingency configuration.
- $N$  is the number of contingencies considered.
- $U_i \in \mathcal{R}^m$  is the vector of control variables for configuration  $i$ .
- $X_i \in \mathcal{R}^n$  is the vector of state variables for configuration  $i$ .
- $Z_i = [U_i \ X_i]^T \in \mathcal{R}^{m+n}$  is the decision vector for the  $i^{\text{th}}$  configuration.
- $f: \mathcal{R}^{m+n} \rightarrow \mathcal{R}^1$  is the base-case objective function representing operating costs.
- $G_i: \mathcal{R}^{m+n} \rightarrow \mathcal{R}^a$  is the vector function representing the load flow constraints for the  $i^{\text{th}}$  configuration.
- $H_i: \mathcal{R}^{m+n} \rightarrow \mathcal{R}^b$  is the vector function representing operating constraints for the  $i^{\text{th}}$  configuration.

### Implementation of SCOPF

In our distributed scheme for SCOPF, we use the regional decomposition technique as in [12], where the regions buy and sell electricity from adjacent regions at prices that are coordinated by negotiations between adjacent regions. All the variables and constraints are the same as defined in [9]. In order to decompose a system by regions, the key point is to find proper coupling constraints between regions. To obtain such coupling constraints, a dummy bus is defined at the border for each interconnected line and then duplicated into two dummy generators in [9] while two hypothetical buses are added to each tie-line and the model of interconnected line is modified in [13]. The objectives of the dummy generators represent the interactions of a region with the rest of the system. For this reason, each region can utilize modified versions of existing OPF software to implement the system-wide distributed OPF.

The secure operation of tie-lines is of prime importance in a large interconnected system. Our approach mainly

concentrates on tie-line security. We propose to solve an SCOPF problem in a sequential manner as follows. We first solve the distributed OPF problem to determine the maximum secure simultaneous transfer capability of each tie-line between adjacent regions by taking only the security constraints imposed on the tie-lines into account. In this case, a tie-line outage is regarded as a generator outage, and the line outage distribution factors (LODF) calculated at the current state are used to formulate the appended constraints. By definition, the line outage distribution factor has the following meaning [5]:

$$d_{l,k} = \frac{\Delta f_l}{f_k^0} \quad (5)$$

where,

- $d_{l,k}$  = line outage distribution factor when monitoring line  $l$  after an outage on line  $k$
- $\Delta f_{l,k}$  = change in flow on line  $l$
- $f_k^0$  = original flow on line  $k$  before it was out of service (opened)

If one knows the power on line  $l$  and line  $k$ , the flow on line  $l$  with line  $k$  out can be determined using the line outage distribution factor.

$$\hat{f}_l = f_l^0 + d_{l,k} \cdot f_k^0 \quad (6)$$

where,

- $f_l^0, f_k^0$  = pre-outage flows on lines  $l$  and  $k$ , respectively
- $\hat{f}_l$  = flow on line  $l$  with line  $k$  out

Once the secure transfer capability of each tie-line, consequently the transfer capability between adjacent regions, is determined, the regional SCOPF is performed using the conventional linear programming (LP) approach described earlier. When performing LP, all the generations from the dummy generators are held fixed.

Fig. 1 summarizes the procedure in implementing the distributed SCOPF. In the procedure, it is assumed that each regional SCOPF can be solved, that is, each region has enough generation units to correct any overloads on transmission lines. However, the infeasible case is not considered in this paper [14], [15]. In the following Section IV, we present a case study to determine the maximum secure transfer capability of tie-lines in Korea Electric Power System using the proposed method.

#### Case Study

The primal purpose of solving the SCOPF is to maintain the system in the steady state after a contingency involving the transmission lines or generators has occurred. In this study, we primarily focus on determining the maximum secure tie-line flows for the tie-lines joining the regions.

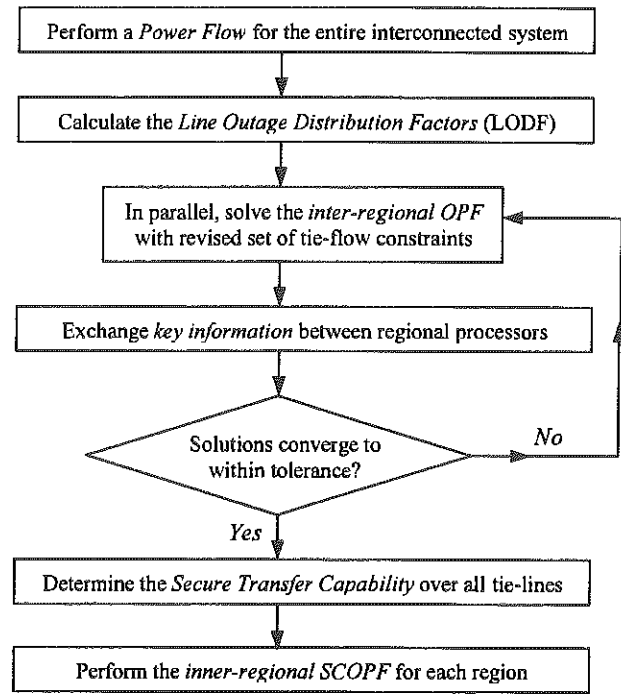


Fig. 1. Distributed implementation of parallel SCOPF

#### Case study system and Test run

We used GAMS 2.25 to simulate the parallel computations involved in the Repeat loop of the algorithm in Fig. 1. Several solvers have been incorporated into GAMS, such as MINOS5, DICOPT, CONOPT, CPLEX, OSL, and XA [16]. In our case studies, MINOS5 and CONOPT were employed. The objective to be minimized is the production cost for active and reactive power. The cost of reactive power is assumed to be  $10^{-6}$  of the active power cost for each generator. We chose the maximum mismatch between the border variables as the stopping criterion:  $10^{-3}$  per unit mismatch for the real and reactive power, and  $10^{-2}$  per unit for the phase angle and voltage magnitude.

Table 1 summarizes the test system. The first column shows the total number of buses in Korea Electric Power System, while the second and third columns show the total number of generators and lines in complete system. The fourth column shows the total MW loads in the system. For the case study, we adopted Korea Electric Power System that was divided into two regions, KyongIn and Non-KyongIn, respectively. Each region is connected directly by the eight major 345kV transmission lines and seventeen 154kV transmission lines. The 345kV and 154kV transmission lines in Korea Electric Power System are treated as the tie-lines that interconnect the two regions, and a single contingency on tie-line is assumed to all 345kV transmission lines. This situation is illustrated in Fig. 2. The most significant features of the 345kV and 154kV transmission lines are given in Table 2 and 3, respectively.



TABLE 1  
CASE STUDY SYSTEM DATA

| Buses | Generators | Lines | Load [MW] |
|-------|------------|-------|-----------|
| 771   | 209        | 1507  | 34459     |

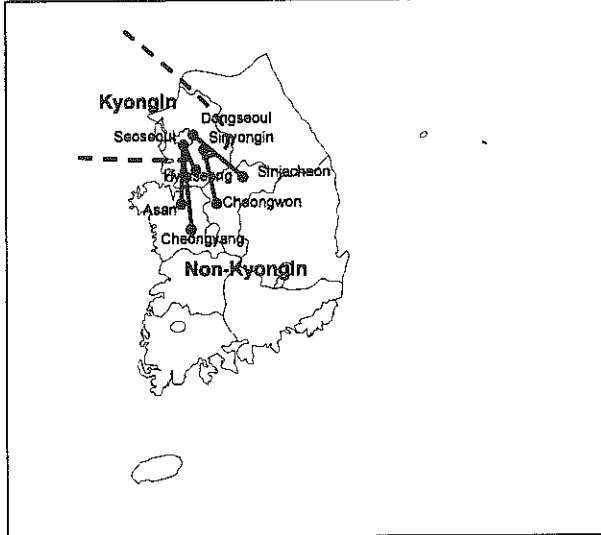


Fig. 2. Decomposition of Korea Electric Power System into two regions

### Case study results

#### STEP 1 : POWER FLOW

We perform power flow for the entire interconnected system to calculate the line outage distribution factors of 345kV transmission lines.

#### STEP 2 : LINE OUTAGE DISTRIBUTION FACTOR

We calculate the line outage distribution factor of each 345kV tie-line as defined in (5). Table 4 and 5 summarize the line outage distribution factors of real and reactive power.

#### STEP 3 : MAXIMUM SECURE TRANSFER CAPABILITY

We determine the maximum secure transfer capability of tie-lines by solving the inter-regional OPF with revised set of tie-flow constraints in parallel. Table 6 shows the maximum capacity, power flow, and maximum secure transfer capability of all the tie-lines in Korea Electric Power System. It is interesting that the availability rate of transmission line that is defined by the ratio of real power flow (PF) to maximum capacity (MC) is less than 40%. In Table 6, we can also see that the SCOPF yields smaller the tie-line flows in overall than does the ordinary load flow. This is mainly due to the post-contingency system security constraints imposed on the SCOPF problems as described in [5, §11]. The key results are shown in Fig. 3.

#### STEP 4 : REGIONAL SCOPF

We derive the secure maximum transfer capability of the selected 345kV transmission lines of each area by performing the inner-regional SCOPFs. To set up a numerical measure for the severity of each transmission line, direct ranking of all the transmission lines in order is necessary.

TABLE 2  
345kV TIE – LINE DATA

| No. | Northward Transmission Line | Circuits | Capacity [MW] |
|-----|-----------------------------|----------|---------------|
| 1   | Sinjecheon →                | 1        | 2192          |
| 2   | Dongseoul                   | 2        | 2192          |
| 3   | Asan → Seoseoul             | 1        | 2192          |
| 4   | Hwaseong → Seoseoul         | 1        | 2192          |
| 5   | Cheongyang →                | 1        | 2192          |
| 6   | Seoseoul                    | 2        | 2192          |
| 7   | Cheongwon →                 | 1        | 1096          |
| 8   | Sinyongin                   | 2        | 1096          |

TABLE 3  
154kV TIE – LINE DATA

| No. | Northward Transmission Line | Circuits | Capacity [MW] |
|-----|-----------------------------|----------|---------------|
| 9   | Cheongpyong HP → Deokso     | 1        | 192           |
| 10  |                             | 2        | 192           |
| 11  |                             | 3        | 192           |
| 12  | Cheongpyong PG → Dongseoul  | 1        | 445           |
| 13  |                             | 2        | 445           |
| 14  | Anseong → Songtan           | 1        | 445           |
| 15  |                             | 2        | 445           |
| 16  | Seocheonan → Pyongtaek      | 1        | 192           |
| 17  |                             | 2        | 192           |
| 18  | Anseong → Yongin            | 1        | 445           |
| 19  |                             | 2        | 445           |
| 20  | Jecheon → Ichon             | 1        | 159           |
| 21  |                             | 2        | 159           |
| 22  | Moonmak → Yaju              | 1        | 445           |
| 23  |                             | 2        | 445           |
| 24  | Umseong → Gangok            | 1        | 445           |
| 25  |                             | 2        | 445           |

TABLE 4  
LINE OUTAGE DISTRIBUTION FACTORS OF REAL POWER

| $k \backslash l$ | 1/2      | 3       | 4        | 5/6     | 7/8      |
|------------------|----------|---------|----------|---------|----------|
| 1                | 0.00000  | 0.01818 | 0.00079  | 0.09168 | 0.22610  |
| 2                | 0.00000  | 0.01818 | 0.00079  | 0.09168 | 0.22610  |
| 3                | 0.12961  | 0.00000 | 0.24477  | 0.61881 | 0.13766  |
| 4                | -0.01569 | 0.45158 | 0.00000  | 0.75480 | -0.02748 |
| 5                | 0.18354  | 0.16283 | 0.10558  | 0.00000 | 0.20406  |
| 6                | 0.18354  | 0.16283 | 0.10558  | 0.00000 | 0.20406  |
| 7                | 0.32058  | 0.02721 | -0.00111 | 0.14965 | 0.00000  |
| 8                | 0.32058  | 0.02721 | -0.00111 | 0.14965 | 0.00000  |

TABLE 5  
LINE OUTAGE DISTRIBUTION FACTORS OF REACTIVE POWER

| $k \backslash l$ | 1/2     | 3        | 4       | 5/6     | 7/8      |
|------------------|---------|----------|---------|---------|----------|
| 1                | 0.00000 | 0.11544  | 0.02576 | 0.78926 | -0.67908 |
| 2                | 0.00000 | 0.11544  | 0.02576 | 0.78926 | -0.67908 |
| 3                | 2.28249 | 0.00000  | 0.65286 | 2.52479 | -0.42980 |
| 4                | 1.98870 | 0.08996  | 0.00000 | 1.08264 | -0.26074 |
| 5                | 1.48588 | 0.41679  | 0.29675 | 0.00000 | -0.55301 |
| 6                | 1.48588 | 0.41679  | 0.29675 | 0.00000 | -0.55301 |
| 7                | 0.02825 | -0.01799 | 0.00560 | 0.04959 | 0.00000  |
| 8                | 0.02825 | -0.01799 | 0.00560 | 0.04959 | 0.00000  |

TABLE 6  
MAXIMUM SECURE TRANSFER CAPABILITY OF ALL TIE-LINES

| No.   | MC    | PF     | MSTP   | MC    | QF    | MSTQ  |
|-------|-------|--------|--------|-------|-------|-------|
| 1     | 2192  | 726.8  | 642.1  | 2192  | 17.7  | 39.5  |
| 2     | 2192  | 726.8  | 642.1  | 2192  | 17.7  | 39.5  |
| 3     | 2192  | 907.7  | 720.5  | 2192  | 66.7  | 114.8 |
| 4     | 2192  | 630.8  | 445.3  | 2192  | 89.3  | 179.5 |
| 5     | 2192  | 593.4  | 532.3  | 2192  | 24.2  | 28.4  |
| 6     | 2192  | 593.4  | 532.3  | 2192  | 24.2  | 28.4  |
| 7     | 1096  | 349.4  | 154.1  | 1096  | -34.9 | -71.1 |
| 8     | 1096  | 349.4  | 154.1  | 1096  | -34.9 | -71.1 |
| 9     | 192   | 74.0   | 96.0   | 192   | 4.0   | 15.0  |
| 10    | 192   | 74.0   | 96.0   | 192   | 4.0   | 15.0  |
| 11    | 192   | 74.0   | 97.7   | 192   | 4.0   | 15.0  |
| 12    | 445   | 130.0  | 200.0  | 445   | 38.1  | 62.7  |
| 13    | 445   | 130.0  | 200.0  | 445   | 38.1  | 62.7  |
| 14    | 445   | -108.9 | -35.2  | 445   | -33.4 | -8.8  |
| 15    | 445   | -108.9 | -35.2  | 445   | -33.4 | -8.8  |
| 16    | 192   | 7.2    | -28.5  | 192   | -41.3 | -40.2 |
| 17    | 192   | 7.2    | -28.5  | 192   | -41.3 | -40.2 |
| 18    | 445   | 75.8   | -20.5  | 445   | -33.3 | -46.7 |
| 19    | 445   | 75.8   | -20.5  | 445   | -33.3 | -46.7 |
| 20    | 159   | 74.4   | 93.2   | 159   | 7.2   | 26.2  |
| 21    | 159   | 74.4   | 93.2   | 159   | 7.2   | 26.2  |
| 22    | 445   | -19.0  | -19.0  | 445   | -3.7  | -6.6  |
| 23    | 445   | -19.0  | -19.0  | 445   | -3.7  | -6.6  |
| 24    | 445   | 51.1   | 51.1   | 445   | -1.4  | 19.6  |
| 25    | 445   | 51.1   | 51.1   | 445   | -1.4  | 19.6  |
| Total | 21072 | 5520.9 | 4594.7 | 21072 | 46.4  | 345.3 |

MC : Maximum Capacity (MW)

PF : Real power Flow by non-security constrained load flow (MW)

MSTP : Maximum Secure Transfer capability of Real power (MW)

QF : Reactive power Flow by non-security constrained load flow (Mvar)

MSTQ : Maximum Secure Transfer capability of Reactive power (Mvar)

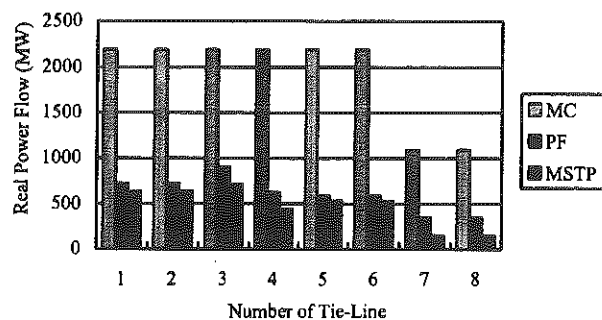


Fig. 3. Comparison of real power flow on 345 kV tie-lines

There is a wide choice of heuristic definitions for the Severity Index. A popular one is

$$SI_i = \left( \frac{T_i}{T_i^{\max}} \right) \quad (7)$$

which is defined for each network branch  $i$ , and where  $T_i$  is the base-case real power flow, and  $T_i^{\max}$  is the branch transmission capacity.

TABLE 7  
TRANSMISSION LINE DATA AND FLOWS OF KYONGIN REGION

| No. | Transmission Line        | Circuits | MC   | PF    | MSTP  |
|-----|--------------------------|----------|------|-------|-------|
| 26  | Yangju →                 | 1        | 2192 | 341.0 | 349.0 |
| 27  | Uijeongbu                | 2        | 2192 | 341.0 | 349.0 |
| 28  | Migeum →                 | 1        | 916  | 365.5 | 266.1 |
| 29  | Seongdong                | 2        | 916  | 365.5 | 266.1 |
| 30  | Seoseoul →               | 1        | 1096 | 698.5 | 523.2 |
| 31  | Yongseo                  | 2        | 1096 | 698.5 | 523.2 |
| 32  | Sinsiheung → Sinincheon  | 1        | 1096 | 150.8 | 29.0  |
| 33  | Sinsiheung → Sinseongnam | 1        | 2192 | 601.1 | 250.9 |

TABLE 8  
TRANSMISSION LINE DATA AND FLOWS OF NON-KYONGIN REGION

| No. | Transmission Line | Circuits | MC   | PF    | MSTP  |
|-----|-------------------|----------|------|-------|-------|
| 34  | Sinyongju →       | 1        | 2192 | 520.4 | 488.9 |
| 35  | Sinjecheon        | 2        | 2192 | 520.4 | 488.9 |
| 36  | Sinnamwon →       | 1        | 1096 | 247.8 | 26.0  |
| 37  | Kwangyang         | 2        | 1096 | 247.8 | 26.0  |
| 38  | Sinpoheung →      | 1        | 2192 | 677.6 | 525.5 |
| 39  | Seodaegu          | 2        | 2192 | 677.6 | 525.5 |
| 40  | Bukbusan →        | 1        | 1096 | 363.9 | 292.2 |
| 41  | Sinulsan          | 2        | 1096 | 363.9 | 292.2 |

MC : Maximum Capacity (MW)

PF : Real power Flow by non-security constrained load flow (MW)

MSTP : Maximum Secure Transfer capability of Real power (MW)

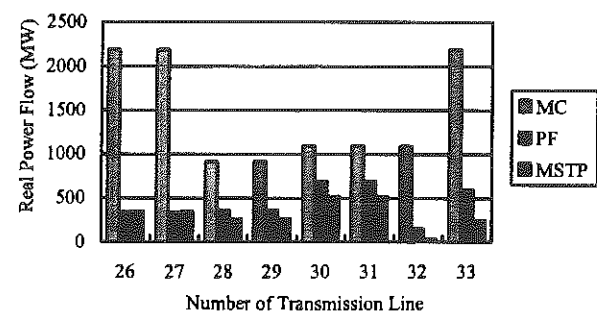


Fig. 4. Real power flow on transmission lines of KyongIn region

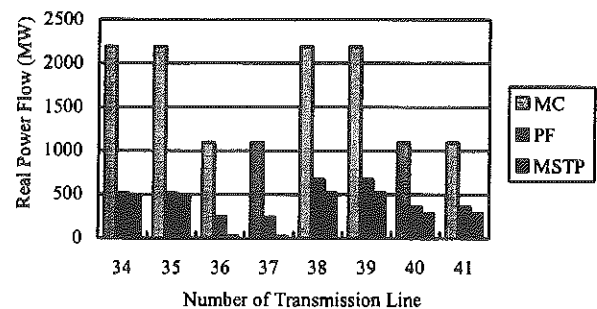


Fig. 5. Real power flow on transmission lines of Non-KyongIn region

Then the inner-regional SCOPFs are performed with the determined power flows of tie-lines that are joining each pair of adjacent regions as fixed power exports or imports. Table 7 and 8 show the maximum secure transfer capability of the selected transmission lines in KyongIn and Non-KyongIn, respectively. The key results are presented in Fig. 4 and 5.

## Conclusion

In this paper, we are focusing on determining the secure tie-line flows for the tie-lines joining the regions. That is, we first determine the secure tie-line flows by performing the inter-regional SCOPF in parallel. Then the inner-regional SCOPFs are performed based on the determined tie-line flows along with the line outage distribution factors of the selected transmission lines.

The case study results are likely to be practical for the northward flow problem that is one of the important power system operation problems in Korea Electric Power System. Our case study is the demonstration of the viability of large-scale distributed SCOPF.

Finally, the incorporation of contingency constraints will also be further studied. The proposed SCOPF approach may not be amenable to the infeasible cases in solving regional SCOPF. We will investigate ways to better represent security constraints and to solve the SCOPF more efficiently and reliably.

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## An operational methodology to assess static and dynamic security of Power Systems facing a large variety of uncertainties

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**Abstract** – This paper deals with a methodology and an advanced practical tool for assessing both the static and dynamic security of a network facing a large number of uncertainties. The motivation for such a development is described, i.e. a background of increasing uncertainty in all time horizons of power system planning and operation. The steps of a study methodology are outlined and the incorporation of advanced security-constrained optimal power flow, dynamic simulation, statistical analysis tools and a specially developed set of sampling functions into a unique user environment is presented. The possible hardware set-ups are described and, finally, some examples of the tool's application are given.

**Keywords** – power system security, dynamic simulation, optimal power flow, uncertainty

### I. Introduction

This paper deals with a methodology and an advanced practical tool for assessing both the static and dynamic security of a network facing a large number of uncertainties.

The non-linear nature of physical phenomena and the size of real power systems make security assessment a complex problem, especially when its dynamic characteristics are examined. In order to articulate definite results applicable to a wide variety of system conditions, it is necessary to simulate a large number of scenarios. This makes it possible to take into account uncertainties on the system state and data, predict security with confidence and devise robust security rules.

The general trend in Europe, due to both economic and environmental pressures, is to operate transmission systems closer and closer to their limits. Liberalisation of markets also increases uncertainty regarding the location and level of generation, thus making the need for and cost of transmission system reinforcement more uncertain. Further, in the context of a market structure, system security limits are seen as constraints preventing the system from being operated purely according to economic rules. Any market actor, facing such constraints, asks for justification. Thus, the comprehensiveness and transparency of the decisions of both the system owner and its operator become important features.

In response to these issues, and thanks to the experience gained by Electricité de France (EDF) in the use and application of data mining methods and by National Grid Company (NGC) in the impact of electricity supply liberalisation, EDF and NGC have decided to join their resources. Together, they are building a practical methodology and the associated software environment, known as 'ASSESS', aimed at executing a large number of simulations on different situations and easily analysing a very large amount of produced results, so as to extract the critical information about system limits and behaviour. This article describes the design and development and its background. The detailed method is presented, together

with information regarding the practical implementation. This latter aspect is especially important as such methods are notably heavy and their practical application can raise many serious difficulties in the absence of a careful application technique.

### II. The growth of uncertainty

#### A. Uncertainty in the planning horizon

The transmission planner needs to consider the long term capital investments required to maintain and develop the network, in order to meet statutory and customer requirements for quality and security of supply. The planner must evolve a strategy which minimizes cost but manages risk [1].

Historically, with generation and transmission centrally planned, a strategy would have involved considerations such as whether to develop generation capacity based on particular fuels, whether to invest in transmission at a higher voltage level or whether to develop interconnections with neighbouring systems. The choice of strategy would have been made by consideration of a relatively limited number of different scenarios concerning economic growth, fuel prices and technological progress. However, within a growing number of industries worldwide, there is no longer any central co-ordination of generation and transmission planning. This leads to considerable uncertainty in required future levels of transmission capacity and hence uncertainty in the need for capital investment. A great many scenarios must be created in order to appreciate fully the scope of the uncertainty and its impact on the delivery and cost of transmission system services. This can only be done practically by means of Monte Carlo simulation of economic and market conditions leading to generation openings and closures and demand growth [2].

The historical convention when faced with a number of 'background' scenarios has been to perform detailed security assessment of the system under a limited number of despatches of the plant assumed to be available. However, in a market environment, generation prices and hence despatches of generation are seen by the transmission planner as stochastic. Thus, a further large set of variants must be analysed in order that an optimal and robust balance of transmission investment and the purchase of 'out-of-merit' generation to secure the system can be found.

#### B. Uncertainty in the operational horizon

Power system operators have always been accustomed to managing uncertainty. Primary among the uncertainties have been the unplanned outage events – contingencies – which

might afflict the system [3]. Deterministic rules have been developed to express simply the contingencies which should be secured against to promote continuity of service without excessive cost. As regards transient events, pessimistic assumptions have usually been made regarding the nature of a fault and the response of automatic equipment. However, in changing economic and social contexts, the idea of 'excessive cost' is not fixed [4], thus the question of appropriate security must be re-addressed and may be refined to provide guidance under different circumstances.

System operators around the world are increasingly responsible for the operation of energy 'spot markets' while retaining a responsibility for security. The behaviour of such markets, and hence the measures which must be taken to ensure system security, are extremely uncertain.

Changing market environments are also leading to increasing cross-border trading, the implications of which system operators are required to manage. This, too, adds to uncertainty in system operation [5].

### C. Reconciling power system complexity with market needs

Due to the non-linear nature of physical phenomena and the size of power systems, it has long been the case that the precise location of a system's limits is extremely difficult to ascertain. However, the growing need for accountability in competitive markets has increased pressure to reduce the operating margin from such limits. Further, it may be argued that environmental pressures which make the construction of new transmission lines and generation extremely difficult, and strict controls on investment by regulators, are making the limits tighter. In the light of the increasing uncertainties noted above, it is thus both more difficult to know the locations and nature of system limits, and more important to do so than has ever been the case before.

Many of the binding system limits are subject to dynamic phenomena, and measures to manage them frequently exploit automatic controls whose interaction is extremely complex. Such measures include Mvar resource coordination, under-load tap-changer blocking, under-frequency load shedding and under-voltage load shedding [6][7]. The design and monitoring of such measures requires computationally exhaustive analysis.

A further issue which becomes ever more important with operation closer to system limits is the accuracy of data which arguably becomes more difficult to guarantee in a deregulated environment. It therefore becomes imperative to study the sensitivity of operational measures to variations in data.

In control room timescales, operators must have confidence that system defence measures are reliable and must have robust operational rules which are straightforward to apply. Since, in the context of deregulation, system security limits are seen as obstacles to the 'natural' operation of the market, the system operator must be capable of justifying fully any operational rules applied.

All of the above phenomena – the uncertainty of future generation capacity, generation despatches, unplanned events,

data and dynamic interactions, and increasing environmental and economic pressures – make it essential that a great many scenarios can be studied. In order to avoid a multiplicity of tools, an extremely flexible, integrated computing facility needs to be provided which

- allows the user to define and easily manage the variations he or she wants to study;
- allows the accurate computation of system responses;
- efficiently manages the large quantity of data created;
- provides ready access to powerful tools which aid the interpretation and understanding of the data.

Such a facility is described in the following sections.

## III. The Methodology

A practical methodology and the associated software environment, known as 'ASSESS', are being developed to address the challenges outlined above. This methodology will :

- execute a large number of simulations on different situations,
- permit the easy analysis of a very large amount of produced results, so as to extract the useful information:
  - how to discriminate between dangerous and secure situations;
  - what are the weak points or boundaries of the system;
  - what is the effect of a given equipment on security improvement.

Conceptually, the objective is as shown in figure 1.

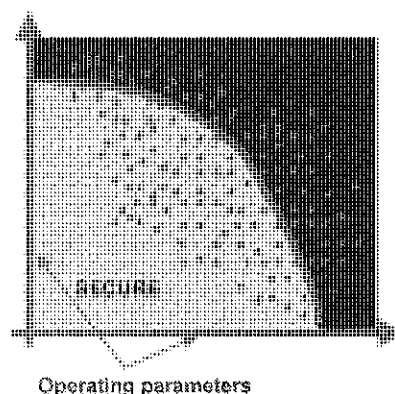


Figure 1: the objective of an 'ASSESS' study

The aim is to build numerous variants, determine whether they are secure or insecure with respect to a given criterion, and to find the operating parameters which best characterise the boundary between secure and insecure states. The operating parameters should be normally expressed only in terms of physical data, e.g. values of flows, inter-area transfers, voltages, internal angles, limits, impedances, costs, etc.. Further there should be sufficient examples of both secure and insecure variants that there can be confidence in the characterisation.

In view of the amount of computation to be done, the design of the software permits the use of a chosen number of computers on a local area network in order to reduce the time taken to generate scenario results.

The main steps of the methodology are

1. definition of the variables prone to statistical sampling and choice of the randomisation laws;
2. definition of a realistic working point for every variant and the assessment of its static security level;
3. study of the dynamic security level of every variant;
4. access to data mining statistical functions and exploration of the results, in order to study the correlation between the variant samplings and the results;
5. refinement of the study by means of further random sampling and simulation.

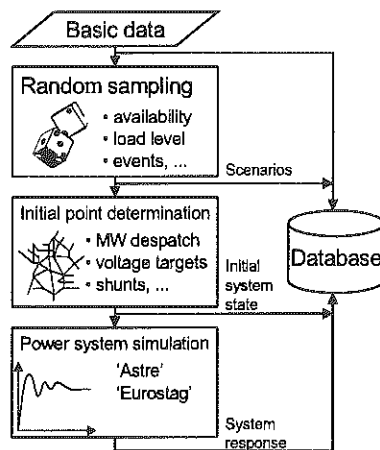


Figure 2: random sampling, initial state determination and power system simulation

The steps are described more fully below.

#### IV. Definition of the random sampling

##### A. Choice of variables

The initial and fundamental work is to choose the main variables that will be able to vary from the base case.

The variables which can be sampled are treated in three domains: static, dynamic and events. Variants created in each of the three domains can be chosen by the user to be combined randomly or systematically. The resulting combination of variants is referred to as a scenario. A scenario must include at least a static variant, though the dynamic and event variants may be 'null', in which case dynamic simulation is not needed.

It would be definitively impossible to sample all or a large majority of the variables. To do so would lead to an unrealistic computational burden, and even if the computations were possible, the statistical analysis would be infeasible in terms of the amount of computation needed and the user's ability to

interpret the results for so many variables. Thus, a careful choice of the number of variables to sample and of the actual devices that will be concerned is essential. To this end, some general guidelines can be presented.

Firstly, as in any classical study, the precise objectives of the study, the relevant tools and the "open" questions around the study must be defined. For example:

- Which strategic equipment options will be compared (if any)?
- Which main types of unavailabilities will be considered, and where? e.g. systematic simultaneous unavailability of  $k$  devices (whether generators, branches, etc.) in the area  $X...$
- Which uncertainty effects of non well-known parameters will be examined, e.g. protection deficiency, regulator gains, constant time, or also operator topology choices ...
- Which security rule should be applied for the definition of the working point of every variant?
- Which criterion will be used to label each computed variant (secure versus insecure)?

On the basis of this preliminary analysis, the choice of variables to sample is dependent on the engineer's judgement. He or she is required to have some ready appreciation of the most relevant variables that are likely to affect the results of the study.

All the technical and economic data which characterise the static state of the system, and all the technical data which characterise the system's dynamic behaviour can potentially be sampled (figure 1). The choice depends on the study aims. For instance, modelling of uncertainty regarding the following static and dynamic variables can be achieved:

- generation capacity, localisation and prices;
- depth and localisation of unavailabilities;
- the impedance of an active fault;
- parameter values of automata (such as shunt connection/disconnection, tap changers, tap changer blocking, load-shedding systems, centralised voltage or frequency regulation...) local regulation devices (voltage or speed regulations...), protections (branches or busbar defaults, voltage and speed protection...).

Events can also be sampled, e.g. the onset and clearance time of transient faults, the timing of switching actions, the loss of particular items of plant and the ramping of load or generation.

A complementary question that must be addressed is the number of variants/scenarios that should be produced: typical values, defined from experience so as to obtain good sample statistical properties are of the order of some thousands (5000 to 15000)...

##### B. Choice of laws

Experience shows that the needed "laws" of sampling are quite complex to deal with the real needs of quite complex phenomena representation.

The sampling laws to which the user has access in 'ASSESS' include standard discrete and continuous probability

distributions, but also have particular rules oriented towards power system analysis. They are listed in table 1 and are described in outline below.

TABLE 1: SUMMARY OF SAMPLING LAW TYPES

| Type | Description                                                                                                                    |
|------|--------------------------------------------------------------------------------------------------------------------------------|
| 1    | Sampling of the value of one variable or one list                                                                              |
| 2    | Sampling of sets of values; some members of a sampled set may be made dependent on other members of the same set               |
| 3    | As for type 2, but sampling of time values.                                                                                    |
| 4    | Sampling for dynamic simulation - sampling of presence/absence of events, items of protection or automata.                     |
| 5    | Sampling of load (active and/or reactive) or of active power generation (used as fixed inputs to initial state determination). |
| 6    | Sampling of network branch and generator in-service/out-of-service states, i.e. availabilities.                                |
| 7    | A 'deterministic' mode allowing the user to impose a chosen value.                                                             |

#### Simple laws

Sampling from Gaussian, exponential or uniform distributions is possible on any one variable. They are typically used to represent general uncertainties.

Another quite simple but useful law permits the random selection of a value from a discrete list of values, each of which has a given probability.

#### Coupled laws

More complex laws, which are frequently necessary, are the "coupling laws". These concern two related variables, the first being sampled and the second being given by some simple function of the first, e.g. a linear equation or a conditional relationship.

A typical example of this law is to model the uncertainty of the type of a new generation unit :  $P_{max}$  cost and other variables of the generator are closely linked and can't be sampled independently.

#### Load/Generation laws

The variation of load is a key determinant of system response. Thus some specific sampling laws have been made available relating directly to load and allowing the user to choose how to sample the total system load, how to distribute it among the individual nodes and how the load power factor should vary.

In a same way, similar laws concerning generation are very useful to represent for example the amount of generation of a given independent producer.

#### Unavailability laws

The definition of the initially out-of-service devices (branches, generators, SVCs, etc.) obviously is also of great importance. These devices can be unavailable due to planned maintenance or previous faults with long return-to-service times. They can also represent the uncertainty on the building of new equipment.

In the same way as for loads, some powerful specific laws have been defined which include the possibility of limiting the number of ('planned') unavailabilities to some maximum, and of making unavailabilities dependent on the in-service states of other devices so as to ensure that a modelled planned outage pattern is realistic.

#### V. Initial state determination

Each sampled variant can be quite different from the base case. Its initial working point must be determined so as to represent a feasible situation such as might be prepared by the operational planners and implemented by operators. This means that the generation start-up and dispatch, the voltage set-points, the switch statuses of shunt compensation, the taps on manually-tapped transformers and phase shifters and the Mvar generation must be realistic. Further,

- the MW dispatch must realistically reflect the likely or sampled market positions of individual generators;
- the determined initial states should respect the chosen security rules whenever possible, e.g. 'N-1', 'N-k', etc.;
- if thermal and voltage security cannot be achieved, adequacy must at least be ensured, i.e. voltage and thermal limits should be respected for the pre-contingency 'planned' system state, i.e. the 'N' state;
- control limits should be respected: maximum and minimum active and reactive power, maximum and minimum taps, etc.;
- the discrete nature of controls such as taps and capacitor banks should be observed wherever possible.

A security-constrained optimal power flow (SC-OPF) is used to achieve this. The particular SC-OPF used – called 'Tropic' [8] – has two parts (see figure 3).

- *Tropic-OPF*: this performs a fully coupled 'AC' single state optimisation of the 'planned' pre-contingency system with additional 'DC' thermal contingency constraints. All controls may be varied to find optimal 'preventive' settings, and generator 'start-up' (simplified Unit Commitment) can be performed.
- *Tropic-Quasar*: this has an AC model of both the 'planned' system and post-contingency systems. Preventive settings of 'reactive' controls are derived to achieve voltage security.

Further, Tropic-OPF has two modes of operation.

- 'external start-up': generators are scheduled first on a purely economic basis, regardless of system constraints, to meet demand plus reserve requirements. This mode could be used, for example, to represent the initial self-despatching of generators in a market such as that of England and Wales or Scandinavia. When the system constraints come to be considered, the costs of deviation from the initial despatch are minimised.
- 'internal start-up': generator 'start-up' and system constraints are considered simultaneously and the MW production cost is minimised.

Quadratic penalty costs for the deviation of reactive power, voltages and taps from nominal values may optionally be added. Quasar minimises the cost of active power losses plus penalty costs. Both parts use non-linear interior point methods, and Quasar makes further use of Benders decomposition to handle security constraints.

Tropic-OPF can manage a full list of  $N-1$  and/or  $N-k$  contingencies (including outages of generation) while Quasar has a practical limitation of around 20-30 contingencies. Thus, some form of contingency ranking is required. This is performed using a tool called 'Astre' [9][10] (figure 2) and is based on a weighted sum of system loadability in terms of voltage and the sum of MVA overloads.

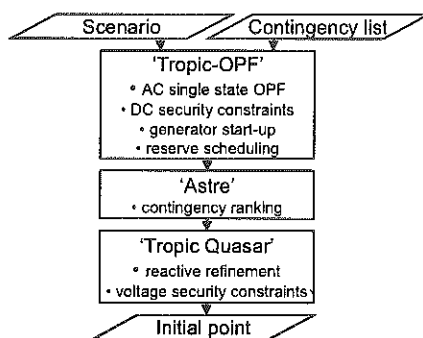


Figure 3 : initial state determination

Since a significant subset of sampled scenarios will impose high stresses on the transmission system, it is important that the SC-OPF is robust. If all the constraints of the SC-OPF cannot be achieved, the criteria are relaxed in a consistent manner so that the initial state remains, to some degree, feasible. In this way, subsequent more detailed analysis of system dynamics can still be meaningful, or useful information may be extracted for inclusion in the database to give an indication of the location and nature of system problems without the need for dynamic simulation. For example, load shedding is scheduled optimally by Tropic-OPF and fixed Mvar injections are added by Quasar. If security constraints cannot be observed, then a single state optimisation is performed. Finally, if stepped devices such as capacitor banks and taps cannot be held at valid discrete values, continuous values are used.

The outcome of the initial point determination stage is a set of a few thousand scenarios with self-consistent initial conditions suitable for dynamic simulation where chosen.

## VI. Power system simulation and result extraction

If the outcome of a security-constrained optimisation and its implicit analysis of static security is not by itself sufficient for the purposes of a study, 'ASSESS' offers a choice of two dynamic tools (figure 2). The user decides which to use depending on the chosen balance between the precision of results, available computation resources and the elementary

computation time. The two tools are 'Astre' [9][10] and 'Eurostag' [11].

'Astre' is a quasi-steady state simulator and is orientated towards the calculation of security margins, i.e. the degree to which the modelled system can be stressed without exceeding thresholds regarding power transfers, voltages, tap-changers hitting limits and a voltage collapse indicator (based on the sensitivity of reactive power generation to reactive load). In the interests of faster simulation, short-term, i.e. transient, dynamics of machines and static devices are assumed to be in equilibrium. Saturation, AVR and governor effects are modelled simply but directly. Long-term controls and protection devices are also modelled, e.g. under-load tap-changing transformers and secondary voltage and frequency controllers. Finally, long-term differential equations corresponding to generic models of load recovery are included.

Eurostag is a time domain simulation tool which models fast electro-mechanical dynamics as well as slow response system controls. Among its characteristics, the following may be emphasised: its versatility for modelling any kind of regulator (regulation blocks are simply defined by the user through a GUI), and its efficiency, due to the use of a variable computation step size. A very large variety of automata models is also available that help to model any centralised or local regulation.

Storage of *all* the possible states calculated by the two simulation engines for a large number of scenarios is infeasible. Thus, only the results requested by the user at the study definition stage (step 1) are extracted and stored in the main database. This is performed automatically by the 'ASSESS' software. However, if more detail is required, the user has the chance to request repeat simulations of chosen variants with additional results extracted (see section V).

## VII. Data mining and statistical analysis

The ultimate aim of this step is generally to separate as well as possible the admissible and the non-admissible situations (figure 1) and to identify the variables which best explain this separation. As described below, this is done in two main stages with further study refinement if necessary.

Once the results have been acquired, ASSESS gives access to a data mining engine. This tool allows the user to study the potentially very large amount of results, filter them and explain them by applying the available methods (figure 4).

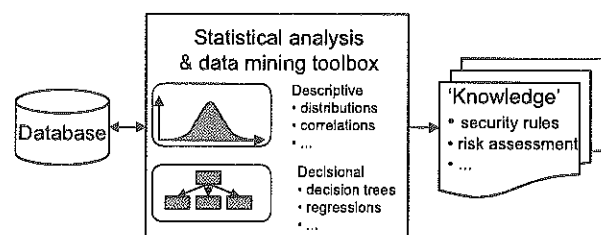


Figure 4: data mining and statistical analysis



### A. Initial characterisation

In this first characterisation, the user is focused on getting a general vision of the results in order to distinguish the main tendencies and identify some raw correlations between some sampled variables and the results. The task is done by applying different requests on the data. Two main approaches are used in parallel:

1. Data-base searching, by means of filters, restrictions, conjunctions, etc. This part deals in fact with classical SQL requests which are easy to carry out because of the power and simplicity of the available GUI for definition of user requests;
2. First level statistical analysis of the sampling. This concerns common methods such as histograms, repartition functions, validity tests, means, variances and correlations.

At the end of this characterisation, the engineer has got a better comprehension of the main parameters. Then, he or she can come back to new sampling and/or computation in order to refine the database, or can go to the second step.

### B. Detailed analysis

The ultimate objective of this phase is to give the definite results of the study. That is, to characterise as well as possible the boundary between secure and insecure states and express it with the most relevant parameters in order to give clear and comprehensible conclusions. In some studies, this second part ends with the definition of a dimensioning or operational rule. Often, it is also very useful to be able to classify the scenarios in different clusters and identify a good example of each one.

Different powerful statistical algorithms are used which can be broadly classified as 'descriptive' or 'decisional' and are outlined below.

#### Descriptive statistics

- "Principal Component analysis" examines relationships within a single set of variables to derive a small number of independent linear combinations of a set of variables that retain as much of the information in the original variables as possible. The purpose of principal component analysis is to simplify the comparison of observations with a great number of observed variables.
- "Canonical Correlation analysis" examines relationships between two sets of variables.
- "Cluster analysis" finds hierarchical clusters of the observations in a data set. This method could be either applied to the scenarios or to the variables.

#### Decisional statistics (models)

- "Regression techniques" (linear, non-linear or logistic) allow the investigation of the relationship between a dependent variable and one or more explanatory variables; they are useful to get understanding, but are not recommended for the production of final characterisation of

the boundary, since their result is a (non-)linear combination of variables, which is generally difficult to interpret in physical terms.

- "Analysis of Variance" is a technique for exploring the variation of a continuous response variable. This analysis allows, for instance, comparison of the means of a response variable over groups defined by one or more classification variables; this is, for example, useful to strengthen the validity of a clustering.
- "Decision Trees" give the complete set of rules used to split the data into a hierarchy of successive segments. A tree consists of branches and leaves, in which each set of leaves represents an optimal segmentation of the branches above them according to a statistical measure. This last tool is frequently used and very much appreciated by the power system engineer, not only because it generally gives a powerful separation, but also because it is a meaningful one, expressed in terms of the unique physical variables that the user has selected as candidates.

### C. Know-how requirements

The use of techniques such as those outlined above needs the user to be well-acquainted with them. On the basis of our present experience, we can give the following information on this topic.

In general, the power system engineer can use these techniques after a specific training of about one or two weeks. The easy-to-use characteristics of the available statistical software, and their ability to give a good information about the statistical validity of the produced results make their use quite easy. (The main difficulty is rather the need for a powerful computer to deal with a large volume of data).

Frequently, the information obtained from the first step analysis is already very significant and is based on the common knowledge of every graduate student.

The use of the more complex second step tools can be more difficult, especially on certain samples. In that case, if possible, the help of an engineer with specialist statistical knowledge for a couple of days, after the first step study, is very efficient, and is strongly advised for an engineer using the tools for the first time.

### D. Study refinement

If needed, chosen parts of the problem space may be further refined for more detailed analysis. This can be done by running another 'set' of simulations as part of the same overall study in two ways.

1. To choose particular scenarios with the same initial conditions and modelled events but for which more detailed results are to be extracted.
2. To choose particular scenarios with the original sampled values but to perform additional sampling on other variables.

With this facility, it is possible to perform a progressively more detailed analysis. For example, at a first stage, the aim may be simply to distinguish between those scenarios which are statically secure and those which are insecure. Then, the scenarios which are statically secure may be examined dynamically, and those scenarios which exhibit instability may be subject to a third set of results in which the nature of the sensitivity of instability to different variables may be explored in more detail.

In the first instance, depending on the nature of the sampling undertaken, the described approach gives statistical results in which the probability of each scenario is not taken into account. However, it is also possible, when necessary for certain studies, to weight the different situations with respect to their relative probability of occurrence in order for the data mining analysis to give a characterisation of risk. The IREP 2001 paper [12] explains how this can be done.

### VIII. The computing environment

Security-constrained optimal power flow and dynamic simulation are both extremely computationally intensive tasks. When many hundreds or thousands of scenarios are to be subject to these kinds of computation, the time needed to achieve results can be very long.

'Coarse grain' parallelism in, for example, dynamic security assessment began to be widely recognized and exploited in the early 1990s (see, for example, [13]). Similar parallelism exists in 'ASSESS' in which each scenario within one 'set' of results in a study is independent of each other scenario in the same 'set'. The increasing availability of local area networks (LAN) and of efficient and easy-to-use network scheduling software means that a large number of cheap and relatively powerful PCs can be exploited to perform the large amount of SC-OPF and dynamic simulation 'number crunching' needed for a study. Indeed, the total solution time is linearly scaleable with the number of PCs.

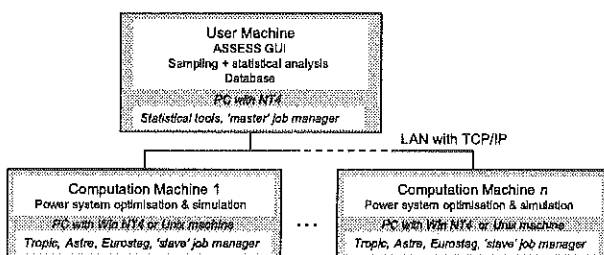


Figure 5: the computing environment

Figure 5 shows the hardware and software environment in which ASSESS exists. There is one unique PC with which the user interacts directly in order to define the parameters of a particular study and perform the statistical analysis. The same PC acts as host for the database. Then, the same PC can be used for the power system simulation, or can be used along with a number of other PCs or Unix servers/workstations on a LAN.

The job scheduling software can be configured to exploit only certain machines at certain times or dependent on the load of particular machines.

## IX. Applications

### A. Domains of application

This method is mainly designed to be used in the following contexts:

- In the context of **system planning** (i.e., investment and expansion planning), alternative system configurations can be screened for many generation and load patterns and a large number of contingencies in order that investments can be well targeted and risks quantified.
- In the context of **operation planning** (i.e. maintenance scheduling, design of operating strategies, protection settings, etc.) security assessment is needed to make better use of available resources, to reduce system operational costs without compromising the security of supply and the integrity of equipment.

Further, ASSESS, could also be used in the context of day-to-day and on-line operation, specifically by performing pattern recognition between the computed scenarios in the database and some actual operational states.

### B. Examples of studies

With such a tool, it is possible to address different types of studies with a greater confidence that all the possible cases have been examined. Some particular examples are:

- needs for new or modified investment on the network;
- comparison of security level resulting of differentiated scenarios of generation growth in terms of localisation and fuels;
- operational rules for primary reserve level and its geographic allocation;
- probabilistic evaluation of the correlation between ATCs on different borders;
- estimation of reactive power generation added value, in order to build a pricing rate;
- secure rules for Under Load Tap Changer blocking, and other actions for voltage collapse mastering;
- identification of the most dangerous contingencies and characterisation of sequence of events leading to major collapses,
- identification of the best detection criteria for loss of stability, choice of load shedding and islanding criteria for system preservation,
- ...

### X. Conclusion

This paper has presented a methodology and a practical software environment for assessing the static and dynamic security of a network facing a large set of uncertainties. The method and the tool are the fruits of a collaboration between Electricité de France and National Grid Company, taking advantage of EDF experience in the use and application of data mining methods and NGC experience in the operation of a deregulated market and the associated planning model. They have been designed to be especially relevant to the present and emerging structures of electricity markets and utilities worldwide.

The methodology described builds a comprehensive approach, based on state-of-the art information technology techniques and power system computation software. It allows the analysis of a very large set of situations, in order to enable many types of studies, from the classical planning questions (asset values, the security rules to respect...) to very technical questions (protection or regulation device performance and settings), through dynamic security assessment. All these studies are managed with a relevant model of the power system market environment.

The method and the tools are very flexible and will be able to evolve in different directions. In particular, the following evolutions could be explored in the near future: integration of probabilities of the scenarios, use of complementary power system software, addition of further, refined sampling laws, interfaces with different statistical software, etc.

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EUROSTAG is a software co-developed by EDF and TRACTEBEL.

ASTRE is a software developed by the Université de Liège (Belgium).

## A Solution of Unit Commitment with Transmission and Voltage Constraints by Heuristic Method and Optimal Power Flow

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**Abstract** In this paper, a heuristic algorithm combined with OPF is proposed for short-term unit commitment problem with transmission and voltage constraints. Being a very complicated combinatorial optimization problem, unit commitment is very difficult to solve, especially, for large-scale power system with network constraints. In recent years, we have proposed a heuristic algorithm based on the average full load cost without network constraints. In this study, we will propose a solution of unit commitment problem with network constraints using combination of heuristic algorithm and OPF. The proposed algorithm has been applied to IEEE 118 test system with 36 generator over 24-period. The result shows that the proposed algorithm is capable to obtain satisfactory schedules without any constraint violation.

### 1. Introduction

Unit commitment problem is an optimization problem to determine the start-up and shut-down schedule of thermal units while satisfying various constraints, for example, generation-demand balance, unit minimum-up/down time, system reserve and so on. Since this problem involves a large number of 0-1 type variables that represent up / down status of the unit and continuous variables expressing generation output, it is one of the difficult combinatorial optimization problems to solve. Essentially, global optimum solution of such a combinatorial optimization problem can be obtained by examining all combinations. However, it is impossible to examine all combinations because the number of combinations is very vast for large systems. Therefore, the study at present is groping the method for requiring the sub-optimum solution efficiently. Several solution technique have been applied to this problem, such as the dynamic programming (DP) approach, the Lagrangian relaxation (LR) method, the branch-and-bound method and the genetic algorithm (GA).

Recently, we have proposed a heuristic method for unit commitment problem, in which unit status will be changed according to the average operating cost of the generator. First, the initial solution is generated randomly by using random numbers. If this solution is infeasible,

the initial solution is generated repeatedly until the feasible solution is found. Next, based on the heuristic rules, units with higher operating cost are decommitted and units with lower cost are committed. If it is impossible to improve the solution with those rules, the result is saved as the solution candidate. The process is repeated for specified iteration number and the best candidate is selected as the solution. In our simulation, we found that the solution obtained by the heuristic method is better than that of the LR and the GA. Also, the solution time is quite faster than those methods.

Unit commitment method widely used solves the problem without consideration of voltage, reactive power and transmission constraints. Several methods have been proposed to consider these constraints. J. J. Shaw proposed a solution of unit commitment based on the Lagrangian relaxation method [4], in which transmission constraints are incorporated into Lagrangian function directly. H. Ma et al. exploit Benders decomposition technique, where the master problem minimize the generation cost for unit status (up/down) and the slave problem solves constraint satisfaction problem for voltage, reactive power and transmission constraints [5].

In this paper, we will propose a solution of unit commitment with voltage and transmission constraints, based on the heuristic method and optimal power flow (OPF). In this method, initial unit status will be determined from random numbers and the feasibility will be checked for minimum start-up/shut-down time and demand-generation balance. If the solution is infeasible, the initial solution will be regenerated until a feasible solution can be found. Next, OPF is applied for each time period with the temporary unit status. Then, the units that have less contribution to the cost are detected and will be shutdown based on the heuristic rule. In the same time, if there are constraint violations, appropriate units will be start-up to dissolve these violations. This process will be repeated until sub-optimal solution is obtained.

The proposed method has been applied to the IEEE 118 bus test system with 36 generating units with successful result.

## 2. Formulation of Unit Commitment Problem

### 2.1 Nomenclature

In this section, a general formulation of UC is presented. First of all, the following terms are defined:

- $i$  : index for units
- $t$  : index for periods
- $k, m$  : index for bus ( $k, m = 1, \dots, NB$ )
- $U_i^t$  : operating status of unit (0: off 1: on)
- $P_i^t$  : output of each unit at period  $t$  [MW]
- $P_i^{\max}$  : maximum output of unit  $i$  [MW]
- $P_i^{\min}$  : minimum output of unit  $i$  [MW]
- $FC_i$  : generating cost of each unit [YEN]
- $ST_i$  : start up cost of each unit [YEN]
- $D^t$  : power demand at each period [MW]
- $R^t$  : spinning reserve of unit  $i$  at  $t$  period [MW]
- $FC_i$  : fuel constraint for unit  $k$  (Yen)
- $\tau_i$  : cooling constant for unit  $i$
- $P_{km}^t$  : line flow between node  $k$  and  $m$
- $P_{km}^{\max}$  : line flow limit between node  $k$  and  $b$
- $V_k^t$  : voltage magnitude at node  $k$
- $V_k^{\max}$  : maximum voltage limit at node  $k$
- $V_k^{\min}$  : minimum voltage limit at node  $k$

### 2.2 Objective Function

The objective of UC is the minimization of the total production costs over the scheduling horizon while observing to all system operation constraints. This objective has a great advantage to be quantitatively formulated easily and can be expressed as the following:

$$\begin{aligned} & \min_{P_i^t, U_i^t} C(P_i^t, U_i^t) \\ & = \min_{P_i^t, U_i^t} \left[ \sum_{t=1}^T \sum_{i=1}^N \left\{ FC_i(P_i^t) \cdot U_i^t + ST_i \cdot U_i^t \cdot (1 - U_i^{t-1}) \right\} \right] \end{aligned} \quad (1)$$

The first term corresponds to the total fuel cost of thermal unit that can be expressed as the function of the generator output. This can be calculated using unit heat rate and fuel price information. The exact expression of the power-cost curve is very complicated. In practice, the following quadratic expression is acceptable for this problem.

$$FC_i(P_i^t) = a_{i0} + a_{i1} \cdot P_i^t + a_{i2} \cdot (P_i^t)^2 \quad (2)$$

The second term indicates start-up cost relating to the features of the thermal system and depending on the length of time that the unit has been stopped. Because the boiler must maintain a certain temperature and pressure to work, it will take more fuel to reach the working state if the unit has been stopped longer and cool. A unit can be disconnected from the system and does not take off fire; this state is refereed as “banking”. If the unit is stopped in banking state, the startup cost-time curve is nearly a line. Otherwise it likes an exponential curve. Costs of labor and maintenance are the other major costs associated with starting a unit. Generally, the startup cost can be expressed by the following equation:

$$ST_i(\tau) = \alpha_{i0} + \alpha_{i1} \cdot \left( 1 - e^{-\frac{\tau}{\tau_i}} \right) \quad (3)$$

where,

- $\alpha_{i0}, \alpha_{i1}$  : startup cost constants for unit  $i$
- $\tau$  : the time that the unit has been stopped
- $\tau_i$  : the cooling time constant of unit  $i$

The shut-down cost is normally independent of the length of time the unit has been operating and is composed primarily of labor and maintenance costs. Thus the shutdown cost of a unit can be defined as a fixed amount of money for each unit per shutdown.

### 2.3 Constraints

There are two types of constraints that must be satisfied by a UC schedule. Those affect units as a group is called “system” or “coupling” constraints while those constrain the operation of each unit individually are termed “horizontal” constraints. Among the constraints, the basic system constraint is that the power supplies the demand reliably. Since the demand is not know in advance and since units and systems can fail, the constraint is usually divided into the following two constraints.

#### (a) Demand-production constraints

The first constraint is that the sum of the nominal power outputs of the units must supply the expected average demand in each time period. This requirement can be given by the following equation:

$$\sum_{i=1}^N P_i^t = D^t \quad (t = 1, \dots, T) \quad (5)$$

#### (b) Spinning reserve constraints

The second system constraint is known as the spinning reserve constraint. The reserve at time  $t$  associated with unit  $i$ , which we denote, is the additional power over what it is scheduled to generate that a unit can provide within a specified, short interval of time (e.g., 10 minutes). This can be expressed as:

$$\sum_{i=1}^N P_i^{\max} \cdot U_i^t \geq D^t + R^t \quad (t = 1, \dots, T) \quad (6)$$

where  $R^t$  is chosen to ensure that, with high probability, the demand can be met even if some units or transmission lines fail or the actual demand varies from the expected demand.

#### (c) Line flow constraints

For an operation schedule, it requires that power flow should not exceed each transmission limits to prevent line overload.

$$-P_{km}^{\max} \leq P_{km}^t \leq P_{km}^{\max} \quad (t = 1, \dots, T) \quad (7)$$

#### (d) bus voltage constraints

The voltage magnitude at each node should be restricted within physical constraints.

$$V_k^{\min} \leq V_k^t \leq V_k^{\max} \quad (t = 1, \dots, T) \quad (8)$$

#### (e) Generator output constraints

The output power of each unit should not exceed its limits. This constraint can be expressed as the following:

$$P_i^{\min} \cdot U_i^t \leq P_i^t \leq P_i^{\max} \cdot U_i^t \quad (i = 1, \dots, N) \quad (9)$$

### (f) Minimum up time and minimum down time

The former stem from physical considerations associated with thermal stress on the unit and are designed to limit equipment fatigue; the latter are based on economic considerations intended to prevent excessive maintenance and repair costs due to frequent unit cycling.

The “state” of a thermal unit can be refereed as the number of hours the unit has been on or off at the beginning of time period  $t$ . The evolution of the state of a unit is expressed as follows:

$$(X_i^{on}(t-1) - T_i^{on}) \cdot (U_i^{t-1} - U_i^t) \geq 0 \quad (10)$$

$$(X_i^{off}(t-1) - T_i^{off}) \cdot (U_i^{t-1} - U_i^t) \geq 0 \quad (11)$$

where,

$X_i^{on}(t)$  : up time for unit  $i$  at period  $t$

$X_i^{off}(t)$  : down time for unit  $i$  at period  $t$

$T_i^{on}$  : minimum start-up time

$T_i^{off}$  : minimum shut-down time.

### 3. Formulation of Optimal Power Flow

As an OPF algorithm, we used a Prime-Dual Interior Point OPF (PDIPM OPF), which was proposed in ref [11]. The general OPF problem can be formulated as:

$$\begin{aligned} & \text{minimize } f(x) \\ & \text{subject to } h(x) = 0 \\ & \quad g(x) - l - \underline{g} = 0, g(x) + u - \bar{g} = 0 \quad (12) \\ & \quad (l, u) \geq 0 \end{aligned}$$

where,

$x$  : state and control variables

$f(x)$  : objective function

$h(x)$  : equality constraints

$g(x)$  : inequality constraints

$\bar{g}, \underline{g}$  : upper and lower limits

$l, u$  : slack variables for inequality constraints

Since the objective of UC problem is to minimize generation and operation cost for thermal units, we choose the objective function  $f(x)$  as the total generation cost which is a cumulus of equation (2) for up state units only. Equality constraints  $h(x)$  correspond to power flow equations and inequality constraints  $g(x)$  contains line flow limits, voltage magnitude limits and generation output limits.

### 4. The outline of proposed algorithm

Fig. 1 shows the flow chart of proposed algorithm. First, an initial solution is generated with random numbers. If the solution is not feasible, the initial solution will be re-generated with different random number series. The initialization stage will continue until a horizontally feasible solution can be found.

Next, the obtained solution will be passed to OPF routine to check the OPF inequality constraints and to identify possible status change units.

Then, a set of heuristic rules is applied to decide status

change units.

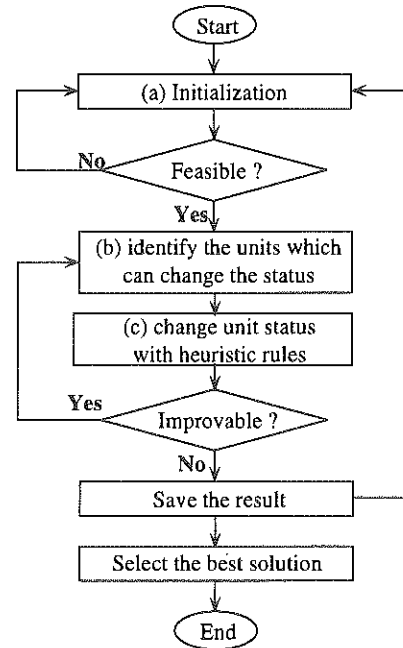


Fig. 1 Flow chart for the proposed algorithm

#### (a) Initialization

The initialization is guided such that units with lower cost are likely to generate more in heavier demand periods. The initial solution is generated randomly where the following rules are applied to obtain feasible solution.

The Average Full Loading Cost (AFLC) is defined as:

$$AFLC_i = \frac{FC_i(P_i^{\max})}{P_i^{\max}} \quad (13)$$

The power generation of a particular unit  $i$  at period  $t$  can be determined by:

$$P_i^t = \beta \cdot \text{RAN} \cdot \frac{\overline{AFLC} \cdot D^t}{\overline{D} \cdot AFLC_i} \cdot P_i^{\max} \quad (14)$$

where,

$$\overline{AFLC} = \frac{1}{N} \sum_{i=1}^N AFLC_i \quad : \text{average of AFLC for all unit}$$

$$\overline{D} = \frac{1}{T} \sum_{t=1}^T D^t \quad : \text{average demand for all time period}$$

RAN is a positive random variable and  $\beta$  is a scaling constant. It is obvious that if the  $\beta$  is large enough, units are likely to be on-line for most of periods. In other words, it is likely to generate a feasible schedule by choosing a large  $\beta$ .

$$P_i^t|_{init} = \begin{cases} 0 & P_i^t < P_i^{\min} \\ P_i^t & P_i^{\min} \leq P_i^t \leq P_i^{\max} \\ P_i^{\max} & P_i^{\max} < P_i^t \end{cases} \quad (15)$$

Equation (15) defines the initial generator output. The zero initial output corresponds to the unit is off-line. On the other hand, if the output was more than zero, then the unit is specified as on-line.

**(b) identify the units which can change the status from OPF information**

Initial solution  $P_i^f$  is passed to OPF routine to identify the redundant up-state units and check the feasibility for OPF constraints  $h(x)$  and  $g(x)$ . In order to express down-state unit, we specified higher cost for the down-state unit as:

$$FC_i(P_i^f) = \delta_i \cdot a_{i1} \cdot P_i^f \quad (16)$$

where  $\delta_i$  is a large number.

Since the fictitious fuel cost for down-state unit (16) are very high, these output will be zero as far as there is a feasible OPF solution with up-state units only. However, if there is no feasible solution, several down-state units have to change its status to up with additional costs to restore feasibility.

The units, that output is stacked to lower limit, will be selected as candidates of decommit units. Among those units, the units with higher *ALFC* will have higher decommitment priority.

**(c) change unit status with heuristic rules**

We will apply heuristic rules to decide which unit should change the status, from the OPF information described above. If the selected unit status change cause the horizontal constraint violation, the strategy will be scraped and we will move to the next priority candidate.

Table 1. System Demand

| hour | $D'$ | $R'$ | % of Peak | hour | $D'$ | $R'$ | % of Peak |
|------|------|------|-----------|------|------|------|-----------|
| 1    | 4242 | 211  | 78%       | 13   | 4895 | 245  | 90%       |
| 2    | 3916 | 196  | 72%       | 14   | 4786 | 239  | 88%       |
| 3    | 3698 | 185  | 68%       | 15   | 4732 | 237  | 87%       |
| 4    | 3589 | 179  | 66%       | 16   | 4732 | 237  | 87%       |
| 5    | 3481 | 174  | 64%       | 17   | 4950 | 247  | 91%       |
| 6    | 3484 | 174  | 64%       | 18   | 5438 | 272  | 100%      |
| 7    | 3589 | 179  | 66%       | 19   | 5385 | 269  | 99%       |
| 8    | 3807 | 190  | 70%       | 20   | 5276 | 264  | 97%       |
| 9    | 4351 | 218  | 80%       | 21   | 5112 | 256  | 94%       |
| 10   | 4786 | 239  | 88%       | 22   | 5003 | 250  | 92%       |
| 11   | 4895 | 245  | 90%       | 23   | 4732 | 237  | 87%       |
| 12   | 4950 | 247  | 91%       | 24   | 4406 | 220  | 81%       |

Table 2. Generating Unit Data 1

| No. | $a_{i0}$ | $a_{i1}$ | $a_{i2}$ | $\alpha_{i0}$ | $\alpha_{i1}$ |
|-----|----------|----------|----------|---------------|---------------|
| 1   | 0.02533  | 25.5472  | 24.3891  | 0.            | 0.            |
| 2   | 0.01561  | 37.9637  | 118.9083 | 30.           | 0.            |
| 3   | 0.01359  | 37.7770  | 118.4576 | 30.           | 0.            |
| 4   | 0.01161  | 37.9637  | 118.9083 | 30.           | 0.            |
| 5   | 0.01059  | 38.7770  | 119.4576 | 30.           | 0.            |
| 6   | 0.01199  | 37.5510  | 117.7551 | 30.           | 0.            |
| 7   | 0.01261  | 37.6637  | 118.1083 | 30.           | 0.            |
| 8   | 0.00962  | 13.5073  | 81.8259  | 80.           | 0.            |
| 9   | 0.00876  | 13.3272  | 81.1364  | 80.           | 0.            |
| 10  | 0.00895  | 13.3538  | 81.2980  | 80.           | 0.            |
| 11  | 0.00932  | 13.4073  | 81.6259  | 80.           | 0.            |
| 12  | 0.00623  | 18.0000  | 217.8952 | 100.          | 0.            |
| 13  | 0.00599  | 18.6000  | 219.7752 | 100.          | 0.            |
| 14  | 0.00612  | 18.1000  | 218.3350 | 100.          | 0.            |

|    |         |         |          |      |    |
|----|---------|---------|----------|------|----|
| 15 | 0.00588 | 18.2800 | 216.7752 | 100. | 0. |
| 16 | 0.00598 | 18.2000 | 218.7752 | 100. | 0. |
| 17 | 0.00578 | 17.2800 | 216.7752 | 100. | 0. |
| 18 | 0.00698 | 19.2000 | 218.7752 | 100. | 0. |
| 19 | 0.00473 | 10.7154 | 143.0288 | 200. | 0. |
| 20 | 0.00481 | 10.7367 | 143.3179 | 200. | 0. |
| 21 | 0.00487 | 10.7583 | 143.5972 | 200. | 0. |
| 22 | 0.00259 | 23.0000 | 259.1310 | 300. | 0. |
| 23 | 0.00260 | 23.1000 | 259.6490 | 300. | 0. |
| 24 | 0.00263 | 23.2000 | 260.1760 | 300. | 0. |
| 25 | 0.00264 | 23.4000 | 260.5760 | 300. | 0. |
| 26 | 0.00267 | 23.5000 | 261.1760 | 300. | 0. |
| 27 | 0.00261 | 23.0400 | 260.0760 | 300. | 0. |
| 28 | 0.00150 | 10.8416 | 176.0575 | 500. | 0. |
| 29 | 0.00153 | 10.8616 | 177.0575 | 500. | 0. |
| 30 | 0.00143 | 10.6616 | 176.0575 | 500. | 0. |
| 31 | 0.00163 | 10.9616 | 177.9575 | 500. | 0. |
| 32 | 0.00194 | 7.4921  | 310.0021 | 800. | 0. |
| 33 | 0.00195 | 7.5031  | 311.9102 | 800. | 0. |
| 34 | 0.00196 | 7.5121  | 312.9102 | 800. | 0. |
| 35 | 0.00197 | 7.5321  | 314.9102 | 800. | 0. |
| 36 | 0.00199 | 7.6121  | 313.9102 | 800. | 0. |

Table 3. Generating Unit Data 2

| No. | $P_i^{\max}$ | $P_i^{\min}$ | MUT | MDT | Initial | Bus |
|-----|--------------|--------------|-----|-----|---------|-----|
| 1   | 12.          | 2.40         | 1   | -1  | -1      | 31  |
| 2   | 20.          | 4.00         | 1   | -1  | -1      | 46  |
| 3   | 20.          | 4.00         | 1   | -1  | -1      | 46  |
| 4   | 20.          | 4.00         | 1   | -1  | -1      | 103 |
| 5   | 20.          | 4.00         | 1   | -1  | -1      | 87  |
| 6   | 20.          | 4.00         | 1   | -1  | -1      | 31  |
| 7   | 20.          | 4.00         | 1   | -1  | -1      | 111 |
| 8   | 76.          | 15.20        | 3   | -2  | 3       | 12  |
| 9   | 76.          | 15.20        | 3   | -2  | 3       | 12  |
| 10  | 76.          | 15.20        | 3   | -2  | 3       | 69  |
| 11  | 76.          | 15.20        | 3   | -2  | 3       | 54  |
| 12  | 100.         | 25.00        | 4   | -2  | 5       | 25  |
| 13  | 100.         | 25.00        | 4   | -2  | 5       | 26  |
| 14  | 100.         | 25.00        | 4   | -2  | 5       | 65  |
| 15  | 100.         | 25.00        | 4   | -2  | -3      | 66  |
| 16  | 100.         | 25.00        | 4   | -2  | -3      | 100 |
| 17  | 100.         | 25.00        | 4   | -2  | -3      | 111 |
| 18  | 100.         | 25.00        | 4   | -2  | -3      | 103 |
| 19  | 155.         | 54.25        | 5   | -3  | 5       | 10  |
| 20  | 155.         | 54.25        | 5   | -3  | 5       | 49  |
| 21  | 155.         | 54.25        | 5   | -3  | 5       | 49  |
| 22  | 197.         | 68.95        | 5   | -4  | -4      | 25  |
| 23  | 197.         | 68.95        | 5   | -4  | -4      | 59  |
| 24  | 197.         | 68.95        | 5   | -4  | -4      | 61  |
| 25  | 197.         | 68.95        | 5   | -4  | -4      | 80  |
| 26  | 197.         | 68.95        | 5   | -4  | -4      | 89  |
| 27  | 197.         | 68.95        | 5   | -4  | -4      | 69  |
| 28  | 350.         | 140.00       | 8   | -5  | 10      | 11  |
| 29  | 350.         | 140.00       | 8   | -5  | 10      | 49  |
| 30  | 350.         | 140.00       | 8   | -5  | 10      | 49  |
| 31  | 350.         | 140.00       | 8   | -5  | 10      | 89  |
| 32  | 400.         | 100.00       | 8   | -5  | 10      | 65  |
| 33  | 400.         | 100.00       | 8   | -5  | 10      | 66  |
| 34  | 400.         | 100.00       | 8   | -5  | 10      | 69  |
| 35  | 400.         | 100.00       | 8   | -5  | 10      | 80  |
| 36  | 400.         | 100.00       | 8   | -5  | 10      | 89  |

MUT : Minimum Up Time

MDT : Minimum Down Time

Table 5 shows the unit up/down status for the obtained best solution, where 0 and 1 correspond to up and down status at each unit, respectively. Unit 28-36 were up at all the time because these generators have very lower AFLC, on the other hand, unit 1-7 were down for most of the time because of higher AFLC. Unit 26, which has lower AFLC and larger capacity, is down for all the time because of the transmission constraints, while the unit is up in the poor solutions.



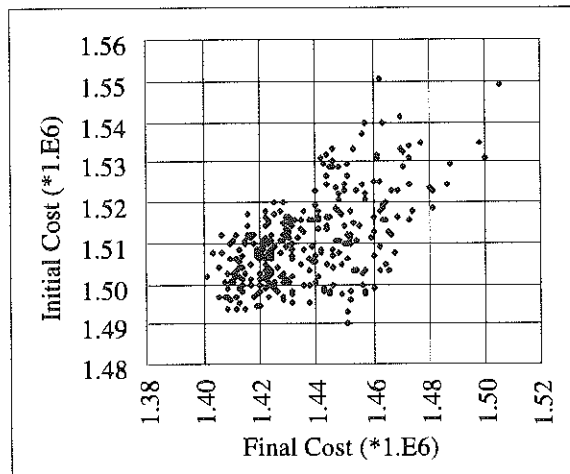


Fig.2 Relationship between initial and final solutions

### 6. Conclusion

In this paper, we have proposed a solution algorithm based on the combination of heuristic algorithm and Optimal Power Flow. The proposed algorithm can handle network constraints such as line flow, voltage magnitude and reactive power limits, easily. The proposed algorithm has been coded and applied to IEEE 118 test system with 36 generators with successful results.

The proper cost coefficients for down state units  $\delta_i$  and more sophisticated rules may improve the quality of solution. This can be a further research topic.

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## Discussions on Session V: OPERATIONS PLANNING Part 2

**Chairman** (S. Iwamoto): Ok, we'll start the discussion.

**C. Canizares** (University of Waterloo): This question is for Professor D. Hur. I would like to have your opinion on this. The first one is, I'm not quite clear how you can obtain this global optimal solution when you're doing this local OPF. I guess you refer to a paper in your reference paper 12. I would like you're a little bit of description how this is done, especially with regard to reactive power. I guess I can understand it, you fix the transmission power flows, the active power flows, because you're trying to secure a given amount of power transmitted. I guess that's what the dummy generator is about, the way I understood it. My concern was the reactive power flow. What happens then? How do you set this to guarantee the local, sub-global, or they are nearby? That is my first question, regarding the methodology for decoupling the network.

**D. Hur**: I use the methodology based on the augmented Lagrangian method, especially auxiliary problem principle, which is the mathematical coordination method.

**C. Canizares**: The next one was more a comment that I would like your opinion on, which is regarding the issue of security constraint of OPF. I have an issue with that because the way security is represented in all these OPF is basically through transmission lines, transmission line power flows. When you're optimizing your system, you're rescheduling generation, loads, etc., also adjusting control variables you have, therefore it redistributes the power flow in your system. Those power flow line limits that you use might not apply any more, they might change to guarantee the security of your system. So I guess I disagree with the security constraint label. I would like your opinion on that.

**J. K. Park**: Thank you for your comments. In my opinion, in our case for South Korea, the northward power flow is very important. It is the operational case. The southern part has the main nuclear plant and the major load in the Seoul area so we want to give some importance to the main transmission line in the middle area. So we want to distribute based on the inner regions, in this case, two regions. We can re-dispatch based on the results. In our case, we will re-dispatch the reduced OPF result into the inner regions, I mean the regions in the southern region.

**C. Canizares**: One quick question about this power flow transmission limits, they were heuristically set?

**J. K. Park**: Yes. At the first stage heuristically, we determine the capacity of all tie lines from the south. We now are investigating everything.

**Chairman**: I would like to come back to Claudio's first question. At the boundary, do you fix the value or not for the optimization? In follow that dummy generator, at that boundary you know the value of P and Q, right? You're putting generator instead of conserving the whole area. How were you doing that? Fixing the value? Or fixing the P and V, or P and Q? I'm not really following.

**D. Hur**: First we calculate the transfer power flow based on the inter-regional OPF first. Then we did the flow, we calculate the next inner OPF.

**Chairman**: So you're doing some relaxation?

**J. K. Park**: It is an iterative process. At the first stage, for example, P and V of this dummy load are specified. From one side, the region one determines this value, and that is given to the region. It's an iterative process.

**C. Vournas** (NTUA): I have two questions. One is to Professor Kubokawa. This question was raised in previous sessions we had. With deregulation in the industry, I think the unit commitment has to be revisited. I have some problems. One problem is how the generating company will make an offer taking into account the cost of starting. The second problem is from the side of the system operator: when committing units from the market, does this decision take into account the minimum time up or minimum time down of the units? So actually the problem exists, but in the new environment. I would like to know if you're considering this. I know that in Japan you're not yet in this stage of market. But just for the sake of solving a difficult problem, have you some solutions to the problem in this new deregulated environment.

**J. Kubokawa**: Yes. We're now expanding our formulation by introducing the agent technology. In that formulation we use the mobile-agent. For example, generator agent, we communicate with generator agents. We have developed some programs and we will present it in the future, hopefully next summer meeting.

**C. Vournas**: In the previous presentation, we saw the decision tree methods were used in southern France to find the critical parameter. Have you used any other method for assessing the critical parameter, like fuzzy sets, or neural networks, or whatever? Can you compare

methods?

**J. P. Paul:** In terms of the method we have used to explore the database, we have made use of different rules, such as principles. It appears that the decision trees are generic methods. Until today, it appears to be a good tool to explore a good explanation of the boundary so we generally rely on this one. Also it is very clear and important to use meaningful variables in your explanation of boundary. We use also principal component analysis, which is a descriptive method than an explanative method. If it does not find the model, you use it to understand the region. It is a projection on the best plan that I mentioned of all the data and all the variables. In fact, you find the true first main direction with the best eigenvalue of all the data set. Generally on this presentation you can understand which variations of data are important, and which variables are important, and which are not, in different situations.

**Chairman:** I think Professor Canizares raised a very good issue. Anybody wants to comment on that? This could be an egg and chicken relationship. For example, any company is really having the optimal power flow program, I mean the AC. Then actually in the AC, your optimal power flow program, I think you have to put some security constraints, right? According to your opinion, the state is different after the optimal calculation, so that security constraint would be also changed. That is what you said?

**C. Canizares:** Yes. You just have to be conservative with those limits and you are fine. But if there is a cost associated with it, people are using this to determine the location for market price. To give you an example in New England, they notice that, through the few months in the process, congestion became a problem. Now, part of the reasons why they want to move over to a different market structure is because of that. Those transmission lines they find congested are creating problems for them, trying to reschedule generation. Once you include them in the process, there is a price to be paid now. So my concern was, I think the OPF process has to be improved. Security has to be better represented. I guess there has been discussion on computing ATC, etc. But my comment was addressed on that direction. I guess we're having the case of the Korean system, they have a very good idea what these limits are, but in some system that's unavailable.

**R. Schlueter:** I understand Claudio's point. I put my hand down because it's such a difficult thing to comment. It really requires a sort of fundamental understanding of what those limits should be - a precise and analytical understanding of what those limits should be. That's a very difficult process. I think that why I raised my hand is because I think that our techniques have a possibility of looking ahead in terms of voltage stability. But on the other hand, you're talking about

thermal constraints. In the process of doing voltage stability, you're going to have it go over line, which has nothing to do with the security, perhaps the thermal security of that system. You're building in thermal problem by doing voltage stability possibly. So in fact, you have to understand what your fundamental limitations are. It becomes very difficult.

**J. K. Park:** I want to mention our situation. That is the reason why we started this research. Before deregulation, there is a very severe limit to the tie line between the North and South because we do not have a sense of economy we only want to keep the security. For example, to increase the tie line flows to get some economy benefits. That's why we started this research.

**Chairman:** I would like to close this session.

**Session VI:**  
**VOLTAGE SECURITY ASSESSMENT &  
STATIC SECURITY ASSESSMENT**

Wednesday, August 29, 16:30–20:00

Chair: Daniel H. Karlsson

## Evaluation of reactive power reserves with respect to contingencies

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### 1. Introduction

Following a disturbance, most generators, synchronous condensers and static var compensators of a power system react to maintain their voltages at (almost) constant values, by producing more reactive power. This is possible as long as no physical limit prevents this additional reactive power from being produced. When such limits are encountered, transmission voltages fall down more or less progressively, until instability occurs either in the form of a loss of synchronism (insufficient voltage support to transfer active power over long distances) or a voltage instability at the load ends (inability of the transmission and generation system to meet the load demand) [1, 2].

Reactive reserves are thus necessary for both angle and voltage stability. Although this paper focuses on the second aspect, the proposed method can be used in a more general context.

It is rather easy to compute or measure the individual reactive reserve available on the above components. However, it is well-known that reactive power cannot be transmitted over long distances. For instance, remote generators cannot provide a significant voltage support. Even if a generator has a large reserve with respect to its physical limit, its effective ability to help containing remote incidents may be limited. In other words, in large systems, reactive reserves cannot be obtained by merely summing up individual reserves.

Although the above facts are well known, there is no clear method to evaluate reactive power reserves with respect to a contingency.

Reference [3] proposed to monitor reactive margins on voltage zones in order to assess the voltage profile quality. A voltage zone is defined as a group of “tightly coupled” generator buses, together with the union of the sets of load buses that they mutually support. The voltage zone margin is the difference between: (i) the zone reserve, obtained by adding the individual reserves of generators within the zone, and (ii) the additional reactive generation needed to maintain acceptable voltage levels after any given contingency. The partition of the system into zones relies on load flow sensitivity information.

References [4, 5] rely on the notion of voltage control area, defined as the set of load and generator buses whose voltages respond “coherently” to outside changes in reactive load and generation. The “reactive reserve basin” of the area is then defined as the sum of the reactive reserves exhausted at the minimum of the VQ curve [1, 2] relative to any bus of the area. The percentage of basin reactive reserve remaining after a disturbance is used as a measure of proximity to voltage instability.

As long as the above voltage (control) areas are identified from sensitivity analysis of a pre-contingency configuration, their validity may be questioned when seeking reserves with respect to instability (not just voltage profile quality) and severe contingencies.

Two methods for determining the “effective” reactive reserve of a specific voltage area are outlined in [6]. The first method relies on VQ curves determined at one bus or for one area. The reserve is taken as the sum of individual reserves of the generators under limit at the minimum of the curve. It is thus an image, on the generation side, of a particular load power margin. The second method computes an effective power reserve as the weighted sum of individual reserves; the weights are based on sensitivities of generator reactive outputs to reactive loads.

The evaluation of reactive power reserves has gained attention within the context of unbundling of generation and transmission. Provision of reactive power reserve is an ancillary service that has to be valued and paid accordingly. The value of this service must be assessed with respect to the capability of helping the system to face incidents.

To value individual reactive reserves, Ref. [7] proposes an “equivalent reactive compensation” method. The latter consists of adding fictitious synchronous condensers at all or selected load buses, and switching all reactive sources under constant power. The synchronous condenser outputs are monitored while the production of each source is varied from base case to maximum capability. This provides a basis for comparing the relative efficiencies of the various sources. Note, however, that transferring voltage control from the generation to the load side results in a fundamental change of system behaviour: load flow divergence, overvoltage and unusual sensitivities problems can be experienced. The proper location of the synchronous condensers is

\* Research Director FNRS (National Funds for Scientific Research, Belgium)

a key step in this method, to avoid abnormal operating conditions and obtain meaningful results.

This paper is organized as follows. Section 2 proposes definitions of respectively the effective capability of a generator, the minimal reactive reserve to face a contingency and the corresponding current value. A simple computational procedure is described in Section 3. Section 4 deals with examples, obtained on a simple test and a real-life system, respectively. Conclusion is offered in Section 5.

## 2. Towards a definition of reactive reserves

### 2.1. Effective capability of generators

Consider the simple 3-bus system of Fig. 1. In this system, the load at bus L is fed by generator 1, electrically close to bus L, and generator 2, located farther away (the lines in Fig. 1 represent both step-up transformers and transmission lines).

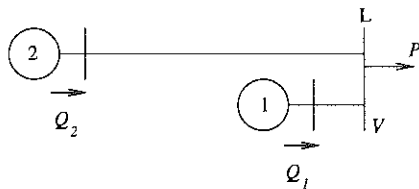


Figure 1: Simple 3-bus system

We denote the generator reactive power capabilities by  $Q_1^{lim}$  and  $Q_2^{lim}$ , respectively. As is well-known, these limits are mainly dictated by the thermal overload capability of the field or armature winding, as depicted by the machine capability curves [1, 2].

Figure 2.a shows the PV curve relating the load voltage  $V$  to the load active power  $P$ . The load is assumed to increase under constant power factor and the two generators respond to the active demand increase according to some participation factors. The breakpoint B corresponds to the loss of voltage control by generator 1, under the action of an overexcitation (or, possibly, a stator current) limiter.  $P^{max}$  is the maximum power that can be delivered to the load by the combined generation/transmission system.

The reactive power response of each generator is considered in Fig. 2.b. Under the effect of reactive power losses, both productions increase more than linearly. As long as it controls its voltage, generator 1, located closer to the load, is more responsive, as indicated by the higher slope of the  $Q_1$  vs.  $P$  curve. For simplicity, we assume that, once under limit, generator 1 has a constant reactive power output  $Q_1^{lim}$  (this simplifying assumption is not needed by the method described in Section 3). When the system operates above  $P = P_B$ , the whole reactive power has to come from the farther generator 2. Hence, the slope of the  $Q_2$  vs.  $P$  curve increases suddenly when passing through point B. At the loadability limit  $P = P^{max}$ , this curve has an infinite

slope, a well-known characteristic of saddle-node bifurcations [2].

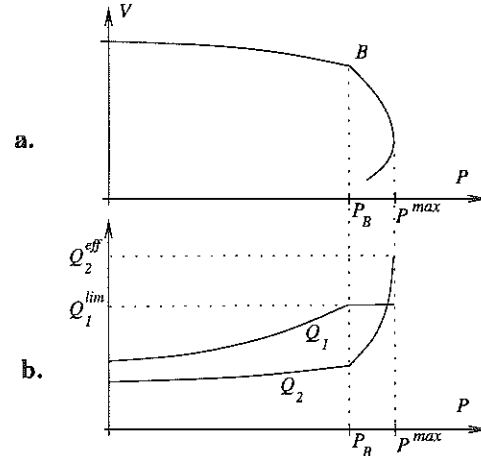


Figure 2: PV and PQ curves of the 3-bus system

Let  $Q_2^{eff}$  be the reactive production of generator 2 at the loadability limit. We call this value the *effective reactive limit* of generator 2, as opposed to the *technical limit*  $Q_2^{lim}$ . For generator 1, which produces  $Q_1^{lim}$  at the bifurcation point, both limits coincide. For generator 2, on the other hand, transmission system constraints prevent from taking advantage of  $Q_2^{lim} - Q_2^{eff}$  Mvars, at least when load is increased at bus L.

The total reactive reserve with respect to the effective capabilities is given by:

$$R = (Q_1^{eff} - Q_1) + (Q_2^{eff} - Q_2)$$

Clearly, this reserve decreases as the load increases and vanishes at the loadability limit point, i.e.

$$R \rightarrow 0 \quad \text{when} \quad P \rightarrow P^{max} \quad (1)$$

What has been said applies to all reactive power sources. We will continue speaking of generators but the proposed definition and method apply to synchronous condensers and static var compensators as well.

### 2.2. Reactive reserves with respect to a contingency

Consider a power system with  $n$  generators in service. We denote by  $Q_i$  the reactive production of the  $i$ -th generator ( $i = 1, \dots, n$ ) at the current operating point and by  $Q_i^{lim}$  its reactive capability.

Following a contingency, most controlled reactive power sources react by increasing their production in order to keep their controlled voltages (almost) constant. In other words, the contingency will “consume” some of the reactive power reserve available on generators. We know that the farther the generator, the lower its support. Hence, the question: *out of the total reserve*

$\sum_i Q_i^{lim} - Q_i$ , how much is needed and on which generators, in order the system to respond to the contingency in an acceptable way?

Whether the system response to a contingency is acceptable must be defined with respect to appropriate criteria. At least, voltage stability is required, but in addition to being stable, the system might be requested to meet some operating constraints.

The approach followed in this paper consists in stressing the system in its pre-contingency configuration, until reaching an unacceptable post-contingency response. A simple analysis of the last acceptable situation will provide us with the sought information, as explained hereafter.

The system stress considered here consists of changes in bus power injections which make the system weaker by increasing power transfer over relatively long distances and/or drawing on reactive power reserves. Namely, at the  $i$ -th bus, the load active power  $P_{li}$ , the load reactive power  $Q_{li}$  or the generator active power  $P_{gi}$  vary according to:

$$P_{li} = P_{li}^o + \lambda_{li} S \quad (2)$$

$$Q_{li} = Q_{li}^o + \mu_{li} S \quad (3)$$

$$P_{gi} = P_{gi}^o + \lambda_{gi} S \quad (4)$$

where  $P_{li}^o$ ,  $Q_{li}^o$  and  $P_{gi}^o$  are the corresponding base case values,  $S$  is a scaling factor, and  $(\lambda_{li}, \mu_{li}, \lambda_{gi})$  are participation factors. Typical stresses consist of increasing load in an area A and generation in a remote area B ( $\lambda_{li}, \mu_{li} > 0, i \in A; \lambda_{gj} > 0, j \in B$ ) or decreasing generation in an area A and increasing generation in a remote area B ( $\lambda_{gi} < 0, i \in A; \lambda_{gj} > 0, j \in B$ ).

Let  $S^*$  be the maximum stress such that the system responds in an acceptable way to the contingency. We denote by:

- $Q_{pre,i}^*$  the reactive power production of the  $i$ -th generator in the pre-contingency configuration, after the system has been stressed at the critical level  $S^*$
- $Q_{post,i}^*$  the reactive power production of the same generator in the post-contingency situation, for the same level of stress.

Since  $S^*$  is such that the system response is marginally acceptable after the contingency has occurred, we consider  $Q_{post,i}^*$  as the effective capability of the  $i$ -th generator. Similarly to what was said in Section 2.1 for a load increase :

- any additional Mvar available on this machine cannot be used to face the contingency in an acceptable way;
- in this particular post-contingency state, some generators may be at their limits while others may still have some reserve. For the latter the effective capability is smaller than the technical one, while for the former both limits coincide.

Thus, the minimal reactive reserve needed to face the contingency with an acceptable response is given by:

$$R^{min} = \sum_{i=1}^n Q_{post,i}^* - Q_{pre,i}^* \quad (5)$$

Now, those generators not involved in (e.g. located far away from) the contingency are characterized by:

$$Q_{post,i}^* \simeq Q_{pre,i}^* \quad (6)$$

and hence, will not significantly contribute to the above sum. In practice, we identify the set of generators involved in the contingency as:

$$\mathcal{E} = \{i : Q_{post,i}^* - Q_{pre,i}^* > \epsilon\} \quad (7)$$

where  $\epsilon$  is a tolerance. Thus, for a small enough  $\epsilon$ , we have:

$$R^{min} \simeq \sum_{i \in \mathcal{E}} Q_{post,i}^* - Q_{pre,i}^* \quad (8)$$

This formulation conveys a bit more information in the sense that it focuses on generators playing a significant role.

The corresponding reserve at an operating point characterized by productions  $Q_i$  is given by:

$$R = \sum_{i \in \mathcal{E}} Q_{post,i}^* - Q_i \quad (9)$$

Note that generators not involved in the contingency may respond to the stress and hence be characterized by:

$$Q_{pre,i}^* > Q_i$$

or, taking (6) into account:

$$Q_{post,i}^* > Q_i$$

Hence, extending the sum in (9) over all generators would include in reserve  $R$  a significant contribution from generators that do not respond to the contingency. Therefore, it is essential to restrict the summation in (9) to the set  $\mathcal{E}$  only. Unless otherwise specified, we will use the corresponding formula (8) for the minimal reserve, for the sake of symmetry.

Finally, note that there is a risk of not including a significant generator in the  $\mathcal{E}$  set, if: (i) it approaches its (technical) limit by less than  $\epsilon$  in the stressed pre-contingency situation, and (ii) hits its limit after the contingency. In this case, one can re-simulate the contingency, at the stress level  $S^*$ , with the limit removed. If the “freed” generator responds by more than  $\epsilon$  to the contingency, it is included in  $\mathcal{E}$ .

### 2.3. A security index

It follows from the above derivation that:

$$R \rightarrow R^{min} \quad \text{when} \quad S \rightarrow S^* \quad (10)$$

which is an extension of (1) including the contingency effect. In fact, (1) can be seen as a particular case of (10) for an infinitely mild disturbance that can be faced without reactive reserve, i.e.  $R^{min} = 0$ .

Clearly, the system is secure with respect to the contingency as long as:

$$R > R^{\min}$$

or in dimensionless form:

$$I = \frac{R - R^{\min}}{R^{\min}} > 0 \quad (11)$$

The larger the index  $I$ , the higher the system robustness with respect to the contingency of concern.

The above indices depend to some extent on the stress chosen to push the system towards its limits. This aspect is further discussed in Section 4.2.

### 3. Computational procedure

The determination of  $R^{\min}$  and  $R$  relies on  $Q_{pre,i}^*$  and  $Q_{post,i}^*$ , which in turn require to determine  $S^*$ , the maximum pre-contingency stress such that the system responds in an acceptable way to the contingency.

This can be done using the simple and robust binary search algorithm. The latter consists of building a smaller and smaller interval  $[S_\ell, S_u]$ , where  $S_\ell$  corresponds to a stable post-contingency evolution and  $S_u$  to an unstable one, until  $S_u - S_\ell$  becomes lower than a tolerance  $\Delta$ . The search starts with  $S_\ell = 0$  and  $S_u = S_{max}$ , a maximum stress of interest. At each step, the interval is divided in two equal parts; if the midpoint is found stable (resp. unstable) it is taken as the new lower (resp. upper) bound. The final value of  $S_\ell$  is the sought stress  $S^*$ . The procedure is sketched in Fig. 3, where the dashed arrows show the sequence of tested stress levels.

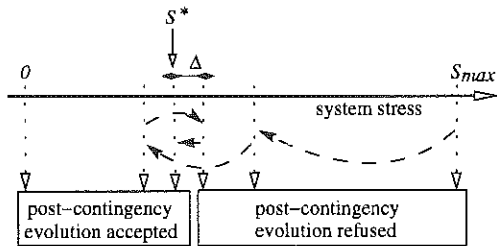


Figure 3: Binary search of  $S^*$

Different tools can be thought of to evaluate the system response, ranging from post-contingency load flows to full time-scale simulations. In this work we have used the fast time-domain Quasi Steady-State (QSS) approach which offers a good compromise between accuracy and efficiency [8, 2, 9].

Note that binary searches are also used to compute secure operation limits with respect to contingencies [9]. In this context, the reactive reserves are obtained at no cost as a by-product of the limit search. In some sense, the index  $I$  is an alternative way of presenting results, looking from the generator side. In addition,

it brings complementary information on the generators responsible for unacceptable voltage profiles.

### 4. Illustrative examples

#### 4.1. Examples from the Nordic 32 test system

We consider the 80-bus, 23-generator system shown in Fig. 4, a variant of the “Nordic 32” system used e.g. by CIGRE Task Force 32.02.08 on Long-Term Dynamics (1995). A rather heavy power transfer takes place from the “North” to the “South” area.

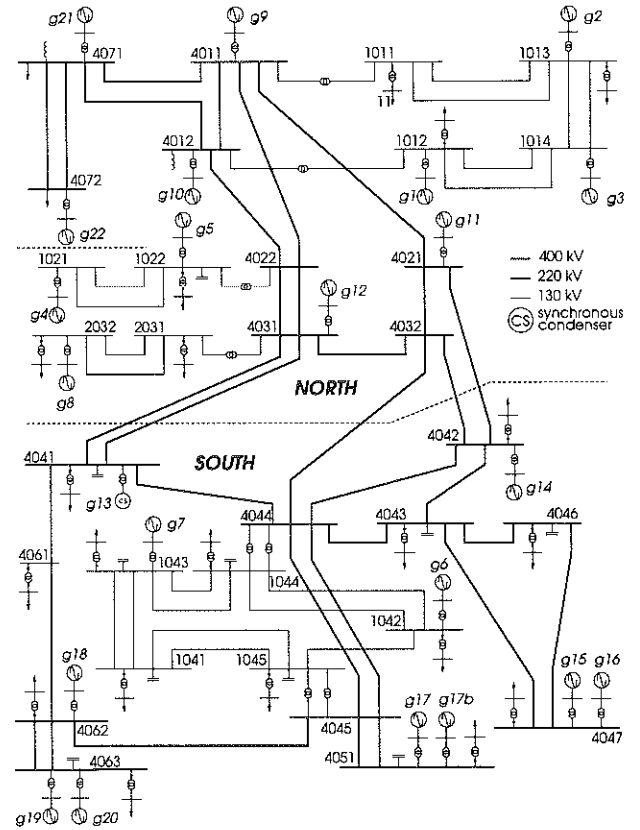


Figure 4: The “Nordic 32” test system

The QSS long-term simulation reproduces the dynamics of Load Tap Changers (LTCs) and OverExcitation Limiters (OELs). Note that there is no slack-bus in the QSS model; instead, generators respond to a disturbance according to governor effects [2]. Moreover, it is assumed that generators of the North area only are under governor control (i.e. the others have infinite speed droops).

The stress of concern is a load increase in the whole system (6 loads in the North, 14 in the South area, with  $S_{max} = 1000$  MW/300 Mvar) covered by a generation increase in the North area (10 generators,  $S_{max} = 1050$  MW, accounting for losses), each according to participation factors.



Figure 5 illustrates the binary search of a limit. It shows the time evolution of a 400-kV bus voltage, under the effect of a contingency applied at  $t = 10$  s. The curves relate to four pre-contingency stress levels: 0 (base case),  $S_i$  (marginally stable),  $S_u$  (marginally unstable) and  $S_{max}$ .

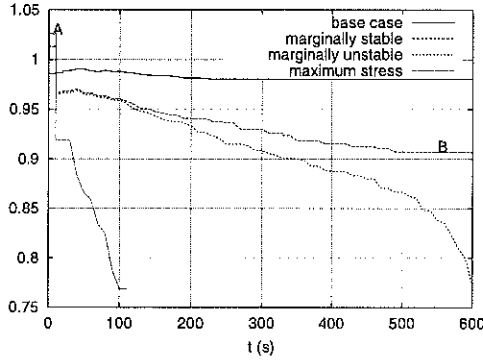


Figure 5: Evolution of a voltage (pu) at 4 steps of a binary search

In this example, the reactive reserves are computed with respect to the risk of voltage instability. Namely, the system response to a contingency is considered acceptable if it is stable; no other operating constraint is added. The  $Q_{post,i}^*$  generations are thus computed at point B of Fig. 5. The base case generations  $Q_i$  are obviously obtained at point A of the same figure.

We present results relative to five contingencies with different impacts on the system. Table 1 gives the corresponding margins  $S^*$ , numbers of generators in  $\mathcal{E}$ , reserves (5, 9) and security indices (11).

Table 1: Nordic 32 system : margins and reserves

| contingency:<br>loss of | $S^*$<br>(MW) | nb of<br>gen.<br>in $\mathcal{E}$ | $R^{min}$<br>(Mvar) | $R$<br>(Mvar) | $\frac{R - R^{min}}{R^{min}}$ |
|-------------------------|---------------|-----------------------------------|---------------------|---------------|-------------------------------|
| g17                     | 440           | 22                                | 2792                | 3943          | 0.41                          |
| 4011-4021               | 497           | 22                                | 2229                | 3575          | 0.60                          |
| 4031-4041               | 668           | 16                                | 1092                | 2865          | 1.62                          |
| g13                     | 893           | 6                                 | 193                 | 1638          | 7.4                           |
| g2                      | 901           | 5                                 | 188                 | 1398          | 6.4                           |

A deeper look into the system behaviour is offered by Fig. 6 which shows for the 23 generators the values of: the base case production  $Q_i^b$  (in black),  $Q_{pre,i}^*$  (in dark grey),  $Q_{post,i}^*$  (in light grey) and  $Q_i^{lim}$  (in white). We take for the latter the reactive power that the generator produces once under field current limit, its voltage and active production being at their base case values. For legibility purposes, the 802 Mvar limit of (the large) generator g9 is not shown. Similarly, g22 is an equivalent generator with a very large capability, not shown either.

Since we use an accurate QSS simulation instead of a standard load flow with constant reactive limits, it is possible for a generator to have:

- $Q_{post,i}^* > Q_i^{lim}$  (see e.g. g5 and g7 in Fig. 6). This corre-

sponds to a generator reaching its field current limit in the post-contingency simulation. Once the limit is enforced, the (uncontrolled) terminal voltage decreases, and the reactive production slightly increases above the base case value taken as  $Q_i^{lim}$ ;

- $Q_{post,i}^* < Q_i^{lim}$  while the generator is field current limited in the post-contingency situation (see e.g. g11 and g12 in Fig. 6). This results from an increase in active power production, due to either the stress or the contingency, causing the reactive power capability to decrease below the base case value.

The results of Fig. 6 illustrate that the effective capability  $Q_{post,i}^*$  is often significantly lower than the technical limit  $Q_i^{lim}$ , due to the network inability to transmit reactive power.

The following observations relate to each particular contingency:

- *loss of generator g17*: almost all generators react to the contingency. For instance, setting the  $\epsilon$  threshold to 20 Mvar leads to having all generators in  $\mathcal{E}$ . While the loss of g17 reactive production (55 Mvar) is compensated by the nearest generators (mainly g17b), the loss of its active production (500 MW) has to be balanced by the generators of the North area, the only ones participating to frequency control. The resulting additional power transfer induces high reactive losses which solicit almost all generators;
- *loss of line 4011-4021*: the 636-MW pre-contingency line power flow is redirected into the 4011-4022 and 4011-4012 lines mainly. Expectedly, the corresponding increase in reactive power losses solicit the Northern generators (g9, g10, etc.), as well as the centrally located g13 and g14. The Southern generators react to a much smaller extent;
- *loss of line 4031-4041*: the generator reaction is somewhat less extended with 16 generators in  $\mathcal{E}$  instead of 22 in the previous two cases;
- *loss of generator g13*: the loss of this synchronous condenser impacts the reactive power balance only. With 6 generators in  $\mathcal{E}$  the disturbance can be considered local. Note that  $\mathcal{E}$  is identified at the  $S^*$  stress, where the compensator produces 133 Mvar. A similar analysis carried out in the base case, where it absorbs power, would not yield such significant results;
- *loss of generator g2*: although both active and reactive powers are lost, almost no effect is felt by the Southern generators.

Coming back to Table 1, a very good agreement is found between the margin  $S^*$  and the security indicator  $I$ . This can be justified as follows. Consider for instance the last two contingencies, which have a large margin  $S^*$ . It is thus required to increase the load by a large amount to make these contingencies harmful. The  $Q_{post,i}^*$  values are thus high and so is the reserve  $R$ . On the other hand, the individual responses  $Q_{post,i}^* - Q_{pre,i}^*$  to the disturbance are small and so is  $R^{min}$ .

#### 4.2. Examples from the EDF system

With a peak load of about 75,000 MW, EDF operates a large system from 7 regional and one national control centers. This system is rather dense and meshed. Much attention is paid to

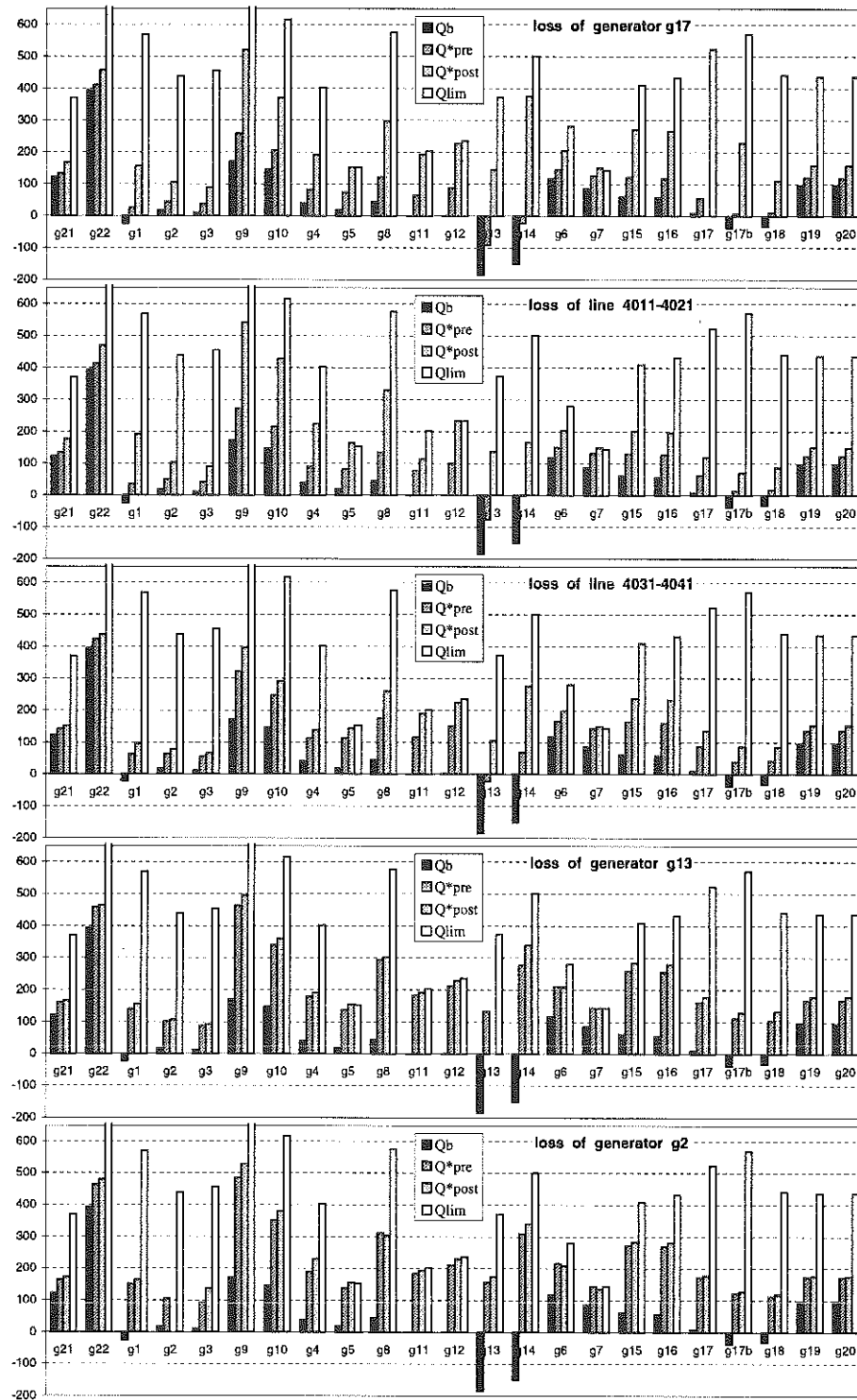


Figure 6: Nordic 32 system : values of  $Q^b_i$ ,  $Q^*_{pre,i}$ ,  $Q^*_{post,i}$  and  $Q^{lim}_i$  of all generators

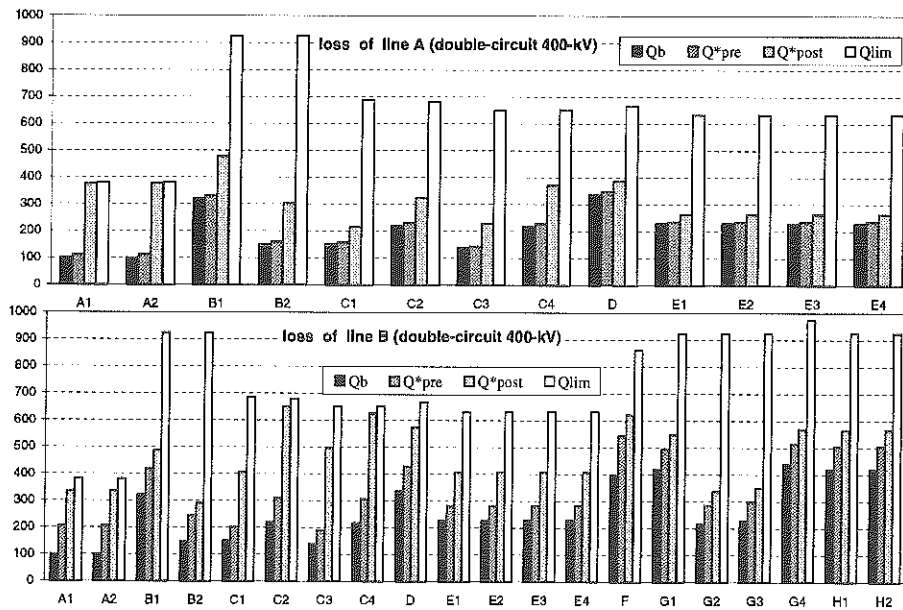


Figure 7: EDF system : values of  $Q_b$ ,  $Q_{pre}$ ,  $Q_{post}$  and  $Q_{lim}$  of generators in  $\mathcal{E}$

voltage security in the Western and South-East regions.

The QSS simulation model includes 1203 buses at the 400 and 225-kV levels together with 512 intermediate buses in the load equivalents, 1024 LTCs, 176 OELs and 15 secondary voltage controllers in the Western and South-East regions. Each of them controls the voltage of some generators so as to keep the voltage of a pilot bus almost constant and the reactive power production of each generator proportional to its capability. Further information on the system modelling can be found in [9, 10].

We present results relative to two  $N - 2$  contingencies, namely the tripping, in the Western part of the system, of two double-circuit 400-kV lines, referred to as A and B, respectively.

We first take as system stress a national load increase covered by French generators. Table 2 gives the corresponding margins  $S^*$ , numbers of generators in  $\mathcal{E}$ , reserves (5, 9) and security indices (11). The loss of line A is a contingency with local effects, the system becoming voltage unstable in its very Western extremity. The margin is small and so is the index  $I$ . The loss of line B has a wider impact but the load must be increased by a much larger amount before this contingency becomes harmful. Expectedly, unlike the small Nordic 32 system, this system has only a small subset of generators involved in each contingency. The more local the contingency, the smaller this subset.

Figure 7, analogous to Fig. 6, relates to generators in  $\mathcal{E}$  only ( $\epsilon = 20$  Mvar). It confirms that the loss of line A has a more local impact. For both contingencies, generators A1 and A2 are the closest to the tripped lines and are field current limited in

Table 2: EDF system : margins and reserves

| contingency: | $S^*$ | nb of | $R^{min}$ | $R$    | $\frac{R - R^{min}}{R^{min}}$ |
|--------------|-------|-------|-----------|--------|-------------------------------|
| loss of      | (MW)  | gen.  | (Mvar)    | (Mvar) |                               |
| line A       | 490   | 13    | 1350      | 1461   | 0.08                          |
| line B       | 4142  | 30    | 2897      | 5165   | 0.78                          |

the marginally accepted post-contingency situation. Generator B1 (resp. B2) has a large reactive capability but the effective reserve is only one half (resp. one third) of it.

Figures 8 to 10 show how the value of  $R$  and  $R^{min}$  relative to a given (base case) operating point changes with the direction of stress used to compute them. To this purpose, loads have been increased homothetically in 12 “concentric” areas, all including the area most affected by the contingency. The abscissa in Figs. 8

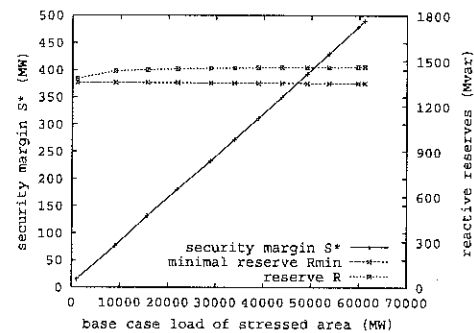


Figure 8: influence of stressed area (EDF system, loss of line A)

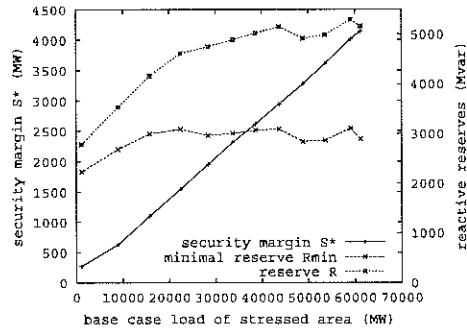


Figure 9: influence of stressed area (EDF system, loss of line B)

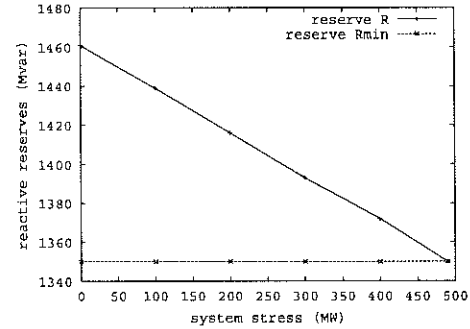


Figure 11: evolution of reserves with stress (EDF system, loss of line A, same stress used to compute reserves)

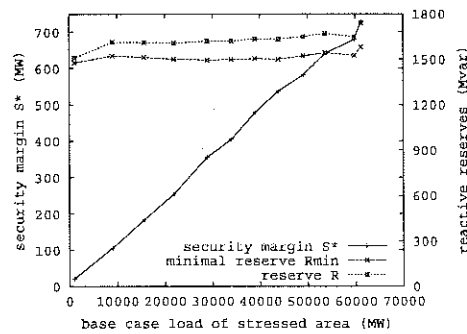


Figure 10: same as Fig. 8 with secondary voltage control

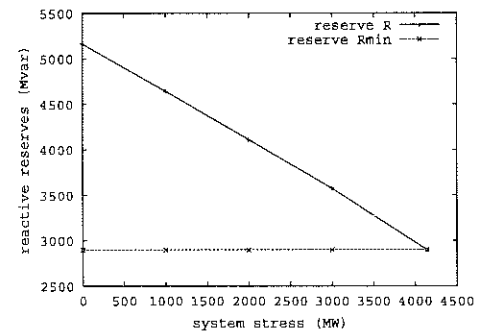


Figure 12: evolution of reserves with stress (EDF system, loss of line B, same stress used to compute reserves)

to 10 is the base case load power consumed in the stressed area. Each figure shows  $S^*$ ,  $R^{min}$  and  $R$ , respectively.

As can be seen, the security margin  $S^*$  decreases (almost) linearly with the size of the stressed area. The minimum reserve, on the other hand, remains rather constant, provided that the stressed area does not approach too much the “heart of instability”. The invariance of  $R^{min}$  for the most dangerous contingency (loss of line A) is noteworthy. The reserves  $R$  undergo more important changes, which seem to follow those of  $R^{min}$ .

Figures 8 and 9 have been obtained in the absence of secondary voltage control. When the latter is in operation, the curves of Fig. 8 become those of Fig. 10. This figure shows the expected improvement in the margin  $S^*$ . The security index  $I$  is also larger.

Figures 11 to 14 show how the reserves evolve with the system stress. Let us emphasize that in all four figures, a national load increase is assumed to compute  $R$  and  $R^{min}$  (this corresponds to the rightmost point in Figs. 8 and 9).

In Figs. 11 and 12 the system is stressed along the direction assumed when computing the reserves. As the stress increases, the available reserve  $R$  decreases. Due to the way it is computed, the minimal reserve  $R^{min}$  remains unchanged. The  $R$  and  $R^{min}$  curves necessarily intersect at a stress level equal to the margin  $S^*$  given in Table 2. The linear variations of both  $R$  and  $I$  are

noteworthy.

In Figs. 13 and 14, on the other hand, the system is stressed more locally, which yields much smaller margins (37 and 355 MW, respectively). Despite the fact that, at each operating point,  $R$  and  $R^{min}$  were computed assuming a national load increase, the  $R$  and  $R^{min}$  curves still intersect at a stress level equal to the margin  $S^*$ . The final increase observed in Fig. 14 is due to some generators lately entering the set  $\mathcal{E}$  as well as a slightly larger response  $Q_{post,i}^* - Q_{pre,i}^*$  to the contingency. The method could still be improved to avoid such variations. Note, however, that the security index  $I$  decreases linearly towards zero as the stress approaches the margin  $S^*$ .

## 5. Conclusion

The ideas developed in this paper can be summarized as follows:

1. the minimum reactive power reserve  $R^{min}$  needed to face a contingency is the total reactive power produced in response to the contingency, when the system has been previously stressed so that its post-contingency operating point is just acceptable;
2. the reactive power produced by a generator at this ultimate post-contingency operating point is taken as the effective capability of this generator, for the contingency of concern. For most generators of a (large enough) system, the effective capability is smaller than the technical one, due to the impossibility of trans-

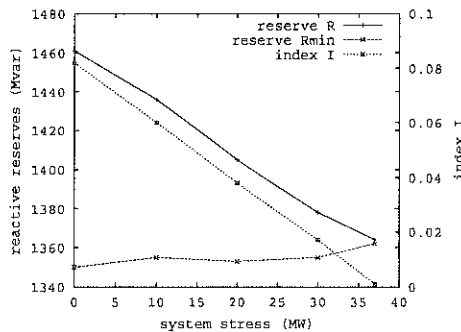


Figure 13: evolution of reserves with stress (EDF system stressed locally, loss of line A)

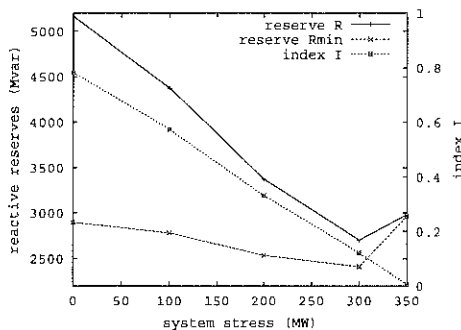


Figure 14: evolution of reserves with stress (EDF system stressed locally, loss of line B)

mitting reactive power over long distances;

3. at a given pre-disturbance operating point, the reactive reserve  $R$  available to face the contingency is a sum of differences between the effective capability and the current production. This sum extends over the set  $\mathcal{E}$  of generators responding significantly to the contingency;

4. the ratio  $(R - R^{min})/R^{min}$  is a convenient, dimensionless security index.

The maximum pre-contingency stress mentioned under item 1 can be obtained using a simple binary search coupled with a contingency evaluation method. If such a binary search is already used to compute the secure operation limit with respect to the contingency, the above reactive reserves are obtained at no additional cost.

Although the proposed method can be used in any context where it makes sense to compute reactive power reserves, the paper focused on voltage instability. Encouraging results obtained on a small test and a large real-life system have been reported.

There is some dependency of the so obtained reactive reserves on the direction of stress used to compute them. However, the results presented in this paper tend to show that, up to some point, the minimum reserve is rather insensitive to the above choice. Also, even if the system is stressed along another di-

rection than the one assumed to compute the reserves, the difference  $R - R^{min}$  between the current and the minimal reserves - and hence the  $I$  index - decreases towards zero as the system approaches an operating point where the contingency becomes harmful. A linear decrease has been observed in many cases.

Whereas the key role of reactive reserves is to support the voltage profile in response to contingencies and stress, and thereby contribute to system security, the concepts summarized under items 1 to 3 above constitute a basis for the valuation of reactive reserves. With respect to a single contingency, it sounds reasonable to reward a generator up to the amount corresponding to its effective capability (see item 2). To take the whole set of credible contingencies into account, one could either consider the maximum effective capability over all scenarios or a weighted sum cumulating the effects of the various contingencies.

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## On Line Monitoring and Preventing of Voltage Stability Using Reduced System Model

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**Abstract** - This paper deals with the development of an on-line methodology for monitoring and preventing of voltage stability process, a methodology based on artificial neural networks with a reduced input data set. The fundamental motive of this research was to establish the most efficient procedure that determines necessary minimal and reliable input data set for the on-line monitoring of voltage instability, as well as to provide a fast on-line evaluation of controllable parameters that have dominant capability of preventing voltage instability process. The proposed methodology is tested on the high-voltage power system of former Yugoslavia that has 92 buses. The obtained results indicate the justifiability of using a reduced system for monitoring and preventing of voltage stability process.

**Keywords:** Voltage stability, voltage control, stability analysis, artificial intelligence and the reduction of power system models.

### 1. Introduction

Deregulation and open market of electric energy produced significant changes in operation of bulk power systems [1]. In such circumstances economical reasons have caused transmission and generation resources often being at the very edge of stability. Under such operating circumstances chance of voltage instability is raised to a significantly higher level, leading to the voltage collapse and system blackout in extreme cases [2,3]. The basic precondition for preventing such severe incidents is prompt and adequate identification of voltage instability. In this sense, of special significance is the development of suitable computer procedures in an on-line environment for monitoring and preventing voltage stability process [4-12].

Procedures for determining voltage stability margin may be based on static or dynamic approach [13]. The static approach is based mostly on the assessment of how the static load flow Jacobian matrix is far from the singular point, namely, from classic static voltage collapse point. Defining an entire series of simple indicators, which show the static voltage stability margins, carries out the practical implementation of this approach [14]. Some of these indicators can be successfully used in an on-line environment, however such a simplified approach frequently renders unrealistically optimistic results. The dynamic approach is based on a dynamic model of the

power system. Following methods, furthermore, are established on this approach: modal (eigenvalue) analysis [15], direct methods [16], dynamic bifurcation [17] and numeric transient simulations [18]. Methods based on the dynamic approach give more realistic picture of voltage stability margins. But, these methods are exceptionally time consuming for the on-line application. Especially attractive method of solving the aforementioned problem is found in artificial neural networks (ANNs). These networks can be trained off-line for especially complicated mapping, such as the problem of determining voltage stability margins, and then be used in the on-line environment. In the relevant literature, an entire series of efficient methods are being proposed, that are based on ANNs and on various indicators of voltage stability [19-21]. Further improvements in efficiency of these procedures may be achieved by using the reduced set of representative variables, them being the leading indicators of system instability, instead of the complete state vector of system variables [22-26]. Devotion of this work goes exactly to this problem.

This paper deals with the development of an on-line methodology for monitoring and preventing of voltage stability process, a methodology based on ANNs with a reduced input data set. The fundamental motive of this research was to establish the most efficient procedure that determines necessary minimal and reliable input data set for the on-line monitoring of voltage instability, as well as to provide a fast on-line evaluation of controllable parameters that have dominant capability of preventing voltage instability process.

The proposed methodology for the on-line monitoring of voltage stability margins is based on both static and dynamic stability margins. These margins are determined by eigenvalue analysis of the linearized static and dynamic models of the power system, and also on the use of multi-layered feed forward and self-organized ANNs. The methodology is composed, as is the practice, of a learning stage and a recall (operation) stage. In the learning stage, first a reduction of the model of the observed power system is done using self-organized ANNs. The reduction of the model, however, is being performed by data clustering and extraction of the reduced sum of the representative system state variables.

The model reduction is performed for all relevant operation configurations. In defining the relevant configurations, all single outages of lines and generators are considered, as well as the most probable combinations of double outages. Then, a stability analysis

is being done over the model reduced in this way. Both the static and dynamic aspects of voltage stability are respected. The static aspect is based on the distance of the operating point from the saddle node bifurcation point which corresponds to the singularity of the linearized matrix of the load flow static power system model, while the dynamic aspect is based on the distance of the operating point from each critical Andronov-Hopf bifurcation point.

Next, on the basis of the results obtained from the stability analysis, the training of multi-layered feed-forward ANNs is done on this reduced model. This ANN is projected and optimized by the use of genetic algorithms, which resulted in its outstanding efficiency. Training is being performed for each relevant configuration by varying the load over the range of the nighttime minimum and daytime peak value. During the training, mapping is established between the reduced input set of system variables, on one hand, and the voltage stability indices on the other hand. Moreover, in all the cases where invasion of stability margins occurs, parameter stability analysis is being performed. This analysis consists of determining numeric influence of controllable parameters to unstable modes. Results of these parameters are being stored in the vector of parameters impact.

During operation based on the reduced set of system variables, monitoring of voltage stability margins of the considered operating steady state is done. The input data in this algorithm in the on-line mode is a reduced (minimally needed) set of measurements from the system. The output from this algorithm represents the voltage stability margin, the unstable modes and the vector of parameters impact. Practically, the vector of parameters impact contains the information as to which controllable parameters have predominant impact to the unstable modes in all cases where the margins of voltage stability are violated. In this way, a clear picture is obtained of which of the controllable parameters should be adjusted to return the system from its unstable state to a stable one.

Using the suggested methodology, clearly there is an open space for coordination of use of controllable resources, in attempt to prevent the process of instability in real-time. Following control resources, which may have crucial influence to the instability in the system, are being taken into account: power system stabilizers, FACTS devices (static VAR compensators and phase shifters), automatic voltage regulators of generators and capacitor banks. All of the above have different available variation ranges of corresponding controllable parameters and its control time response. Finally, an appropriate coordination of control resources is recommended for prevention of instability process, it being based on time decomposition of influences of all mentioned regulation recourses (being their controllable parameters), as well as on optimization procedure that uses numerical influences of specific controllable resources to unstable modes.

The proposed methodology is comparatively tested with a method for monitoring and assessing voltage stability that is based on the complete input set. The tests are done on the eastern part of the high-voltage power system of former Yugoslavia that has 92 buses. The obtained results indicate the

justifiability of using a reduced system in the learning stage through the increased efficiency and quality of learning of the ANNs, as well as in the exploitation stage through the increased efficiency and reduction of measurements required from the system. Finally, on-line assessment of numerical influence of controllable parameters to unstable modes has opened a wide range of possibilities of influence to different regulation resources by prevention of voltage instability in real-time.

## 2. Concept of the proposed methodology

The proposed methodology for monitoring and assessment voltage stability is based on self-organized and multi-layered feedforward ANNs. It consists of four stages [26]: (1) Configuration and design procedure; (2) Stability analysis; (3) Reduction of the system model using an self-organized ANN and an extended AESOPS algorithm, and training the multi-layered ANN over such a reduced model; (4) Exploitation - that is the monitoring and assessment of voltage stability margins. In the text that follows, the basic steps in the proposed methodology are briefly elaborated.

### 2.1. Configuration and design procedure of the ANNs

In the learning stage, four ANN configurations are considered (Fig.1):

- 1) UR is a self-organized ANN intended for the reduction of the vector of system variables [24]. The input into this ANN is the complete vector of system variables and the output is the reduced vector of system variables. Reduction of the vector of system variables is done for each relevant topology.
- 2) NT is a multi-layered ANN for detecting system topology. The input into this ANN is the complete vector of system variables, and the output is the binary identification code of the topology.
- 3) NY is a unified multi-layered ANN for evaluating voltage stability margins for each considered topology of the power system. The input into this ANN is the complete vector of system variables and the identification code of the topology, and the output is the real part of the critical eigenvalue and also the voltage stability margin.
- 4) NR is the multi-layered ANN for evaluation of the voltage stability margin for the considered topology of the power system. The input into these ANNs is a reduced vector of system variables and the output is the real part of critical eigenvalue and also the voltage stability margin.

By combining these four configurations, the two global algorithms (those considered in this paper) for analyzing stability are obtained:

- AY - an algorithm based on a combination of NT and NY configurations of the neural networks (Fig.2);
- AR - an algorithm based on a combination of NT, UR and NR configurations of neural networks (Fig.3).

All the mentioned ANNs were configured with one input layer, one output layer, and one hidden layer each. If the number of hidden layers is increased to two, the learning time is increased

significantly and there is not increase in accuracy. The number of neurons in the hidden layer for all observed networks was designed so that a minimal square error was obtained [10,13]. For most of the ANNs observed in this paper, the number of neurons in the hidden layer was 30% less than the number of neurons in the input layer. The ANNs for detecting system topology had a sigmoidal activation function for the neurons in the hidden layer, and for the neurons at the output layer the activation function was a pure linear function. The ANNs for evaluating system stability had a tangent hyperbolic activation function for the neurons in the hidden layer, and for the neurons at the output layer the activation function was a pure linear function.

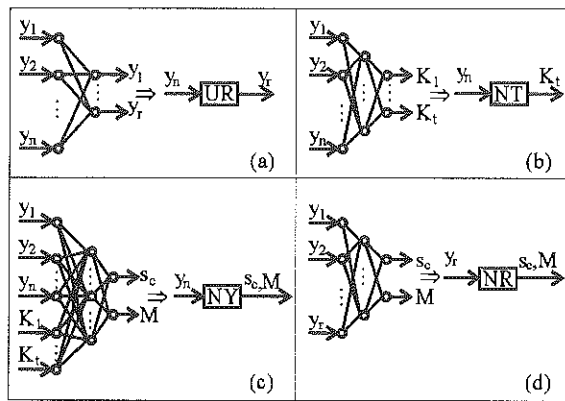


Fig. 1. Configuration of ANNs considered

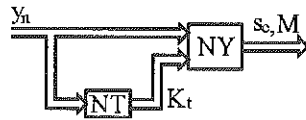


Fig. 2. Algorithm AY based on the complete input set of system variables

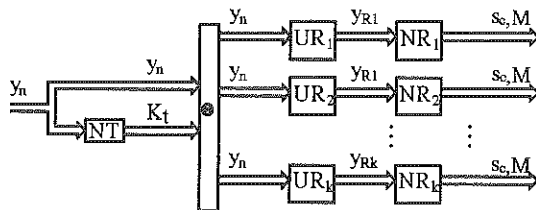


Fig. 3. Algorithm AR based on the reduced input set of system variables

## 2.2 Stability Analysis

The basic stability analysis model used in this paper was taken from reference [13]. In addition, this model was extended to accept the following components: standard types of turbines and governing systems, basic types of AVRs including the PSS [9] as well, and finally an aggregate model of an induction machine [27]. In this model, the fast transient processes in all machines stator/network are ignored. The elimination of these

transients leads to a standard singular perturbation form of the description:

$$\dot{x} = f(x, y) \quad (1)$$

$$0 = g(x, y) \quad (2)$$

where  $x$  and  $y$  are the vectors of dynamic state variables and algebraic system variables, respectively.

$$x = (x_M, x_{AVR}, x_G) \quad (3)$$

$$y = (\theta, V, P, Q) \quad (4)$$

where the following symbols are used:

$x_M, x_{AVR}, x_G$  - the sub-vector of dynamic state variables of synchronous and induction machines, the sub-vector of AVR dynamic state variables including the PSS and dynamic state variables of the turbine and governing system, respectively;

$\theta, V, P, Q$  - the sub-vector of voltage phase angles, the sub-vector of voltage magnitudes, the sub-vector of injected active powers and the sub-vector of injected reactive powers of all nodes in the observed power system, respectively. Monitoring and assessment of voltage stability in this paper are actually based on the algebraic system variable vector and on various combinations of its sub-vectors -  $\theta, V, P, Q$ .

For stability analysis, the algorithm from Fig.4 is used. Both the static and dynamic aspects of voltage stability are respected. The static aspect is based on the distance of the operating point from the saddle node bifurcation point which corresponds to the singularity of the linearized matrix of the static power system model, while the dynamic aspect is based on the distance of the operating point from the critical Hopf bifurcation point which corresponds to the null real parts of the pair of complex eigenvalues of the linearized matrix of the dynamic power system model.

Stability analysis is principally differentiated for the AR algorithm which is based on a reduced system model and for the AY algorithm which is based on the complete system model. Stability analysis for the AR algorithm is carried out in six steps (Fig.4). The calculation of stability analysis begins by taking the night minimum as the starting system load (this load is then distributed to all loaded buses according to the specified distribution coefficients and a random number generator). In the first step, the observed load level  $P$  determines the stationary point  $(x^0, y^0)$ . In the second step, linearization of the dynamic model is carried out using the thus defined stationary point. Then, elimination is carried out of the algebraic system variable vector  $(y^0)$  for dynamic stability analysis, and then the elimination of the dynamic state variable vector  $(x^0)$  for the analysis of static stability. In this way, linear models are obtained for dynamic and static voltage stability analysis. In the third step, system reduction is carried out. First, by applying the self-organized ANN from the vector of dynamic and algebraic variables  $(x, y)$ , the reduced dynamic and algebraic vectors  $(x_R, y_R)$  are obtained, and then by applying an extended AESOPS algorithm from the dynamic and static system matrix  $E$  and  $F$ , the reduced system matrices  $E_R$  and  $F_R$  are obtained [15]. In this way, reduced dynamic and static system models are obtained (the application of self-organized ANNs for reducing vectors  $x$  and  $y$  is described in the next section, while the



application of the extended AESOPS algorithm for system reduction is described in Appendix A.

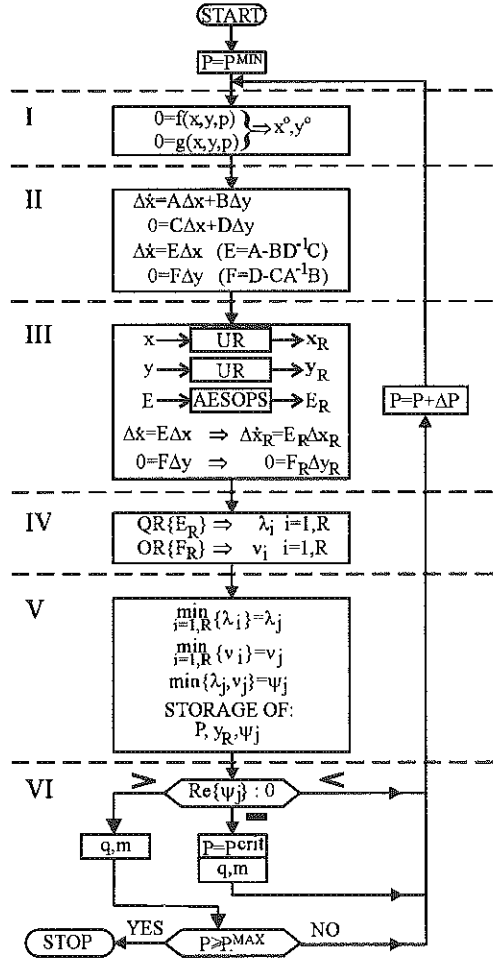


Fig. 4. Flow chart of the algorithm for stability analysis

In the fourth step, by applying the QR algorithm to the thus reduced static and dynamic models, the eigenvalues are determined. In the fifth step, the smallest eigenvalues are determined and then the following variables are recorded: actual load level ( $P$ ), the reduced vector of algebraic system variables ( $y_R$ ), and the smallest (critical) eigenvalue ( $\psi_j$ ). In all cases where the margins of voltage stability are violated a calculation is used for vectors of parameter's sensitivity coefficients of the critical eigenvalue ( $q$ ) and stability margins ( $m$ ). These vectors include parameters for sensitivity of changing critical mode, being the margins of stability compared with the change of controllable system's parameters. The calculation of these parameters is defined in Appendix B [28-30]. This vector is then associated to the critical mode and appropriate level of load in the system (that is the appropriate collection of values of reduced system variables). Finally, In the last step, testing is done to see if the critical load level ( $P^{crit}$ ) has been reached and if all

conditions for completing the calculation have been fulfilled.

When all conditions for completing the calculation have been fulfilled, the voltage stability margin is determined for all operating points, using the equation:

$$M = \frac{P^{crit} - P}{P^{crit}} \quad (5)$$

Calculation of the stability analysis for the AY algorithm is standard and is different from the described calculation in that it does not contain step three for system reduction. In this way, stability analysis and determination of eigenvalues is done for the entire system model.

### 2.3. Unsupervised and supervised learning of the ANNs

Multi-layered and self-organized ANNs are used in the proposed methodology. Self-organized ANNs are used for reduction of the system model and of the input set for multi-layered ANN learning, while multi-layered ANNs are used for detecting topology, and for monitoring and assessment of voltage stability.

a) *System reduction using self-organized ANN [25,26].* The self-organized ANN was introduced in order to shorten the learning time of the aforementioned ANN and to reduce the number of system variables needed for voltage stability margin monitoring and assessment. According to this method, the problem of reducing the vector of system variables from the viewpoint of the ANN can be presented as a problem of extracting characteristic variables and/or variables which differ greatly one from another. In other words, the algorithm developed for the reduction of the vector of system variables, groups its coordinates which are sufficiently proximate in time, and separates the dissimilar ones. The state variable which is closest to the calculated center of group is taken as the characteristic representative of that group. Finally, by grouping all characteristic representatives of the group in one vector, the reduced system vector ( $y_R$ ) is obtained. If only the chosen representative of each group is observed during the formation of the system model, the dimension of the system description can be greatly decreased.

b) *Supervised learning of the ANNs.* After system reduction using the results of stability analysis on a reduced set of system variables, learning is carried out. Supervised learning of a multi-layered ANN is a process in which the correction of synaptic weights between neurons in proximate layers is carried out. The error back-propagation algorithm with a variable learning rate is used for these purposes. The general expression for the correction of the synaptic weights is well known as the generalized delta rule.

### 2.4. Exploitation of the ANNs

After selecting the ANN configuration with the most suitable characteristics, it is possible to move on to the next stage - exploitation. First, the system topology is detected. Next, an evaluation of the stability of the power system with the

identified topology on the basis of complete or reduced vectors of system variables is carried out. A schematic overview of considered variants of the exploitation stages is shown in Fig.2 and Fig. 3.

Monitoring of voltage stability margins is done by introducing measured and estimated system variable values into the input of the corresponding neural network (algorithms AY and AR).

Voltage stability assessment is done by testing if there is an outage of any single element (lines or generators) or if any of their probable combinations lead to a disruption of the voltage stability margins. For the simulation of the considered outages, next two approaches are used:

**ISA (Indirect Stability Assessment)** - The first approach is indirect and is performed so that for each outage, an evaluation is first done of the vector of system variables by applying the fast decoupled load flow calculation. Then, on the basis of the vector of system variables and the specified identification code for the topology of the outage in question, the voltage stability margin of the observed outage is tested by applying one of the suggested ANNs.

**DSA (Direct Stability Assessment)** - The second approach is direct, and is performed so that, the input of the ANN is the input vector  $y=(P,Q)$  consisting of actual injected active and reactive powers in all buses and the identification code of the outage. In this way, the voltage stability margins of the observed outage are directly evaluated without the fast decoupled load flow calculation.

### 2.5. Algorithm for stability monitoring

Practically, algorithm for instability monitoring consists of two parts: (a) training stage and (b) on-line operation stage (Figure 5). During the training, mapping is established between the reduced input set of system variables ( $y_R$ ) and system load level ( $P$ ), on one hand, and the voltage stability margin ( $M$ ), the real part of critical eigenvalue ( $\psi_j$ ), as well as the vectors of parameter's sensitivity coefficients of the critical eigenvalue ( $q$ ) and stability margins ( $m$ ) on the other hand (Fig.5a). Finally, during operation based on the reduced set of system variables, the monitoring of voltage stability margins of the considered operating steady state is done (Fig.5b). The input data in this algorithm in the on-line mode are a reduced (minimally needed) set of measurements from the system. The output from this algorithm represents the voltage stability margin, the critical eigenvalue and the vectors of parameter's sensitivity coefficients of the critical eigenvalue ( $q$ ) and stability margins ( $m$ ). In the case where the margins of voltage stability are violated in the vectors of parameter's sensitivity coefficients of the critical eigenvalue ( $q$ ) and stability margins ( $m$ ), the information is retained as to which controllable system parameters are predominantly influence on the critical eigenvalue, which means in the unstable mode, thus causing instability in the system. In this way, a clear picture is obtained of which of the controllable parameters should be adjusted to return the system from its unstable state to a stable one.

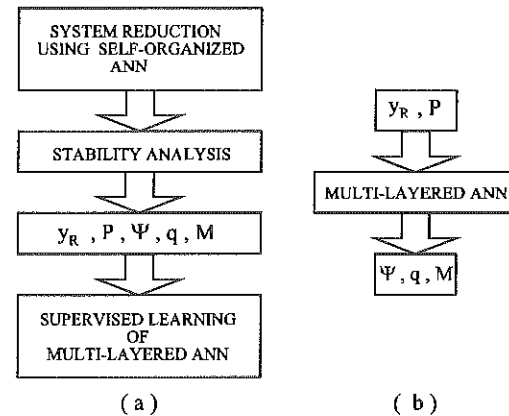


Fig. 5. Flow chart of the algorithm for monitoring of voltage stability

### 3. Methodology for on-line preventing of voltage instability

In this part a global algorithm is presented for on-line preventing instability. This algorithm is based on a reduced collection of representative system variables, as well as the vectors of parameter's sensitivity coefficients.

#### 3.1 Algorithm for on-line preventing of voltage stability

Global flow-chart of this algorithm is presented in the Fig.6. Algorithm is run periodically with user specified period (10 - 30 sec). In every cycle, first it is conducted monitoring of the representative collection of system variables  $y_R$ . In the next step, based on the monitored collection of variables, a test is performed to detect instability in the system. If the instability is not detected in the process, return is proceeded, to the beginning of the next cycle of monitoring collection of the representative system variables.

In opposite case, if the instability is detected, it moves to the next step - adjustments of controllable variables of control devices. This step is time-decomposed, depending on the speed of response of control devices, to the three sub-steps:

- 1) Adjustments of devices with fast response.
- 2) Adjustments of devices with medium response.
- 3) Adjustments of devices with slow response.

With the first detection of instability, only the first sub-step of adjustment procedure is realized. There it is performed adjustment of parameters of control devices with fast response only. Afterwards, again it is performed monitoring of actualized values of system variables and detection of instability. If instability is detected once again in the network, it moves to the following two sub-steps, in the same way. This process is performed until it is concluded that the process of instability is amortized. In every one of these sub-steps an adjustment is performed of only those controllable parameters that have influence on amortization of unstable mode above the specified limit.

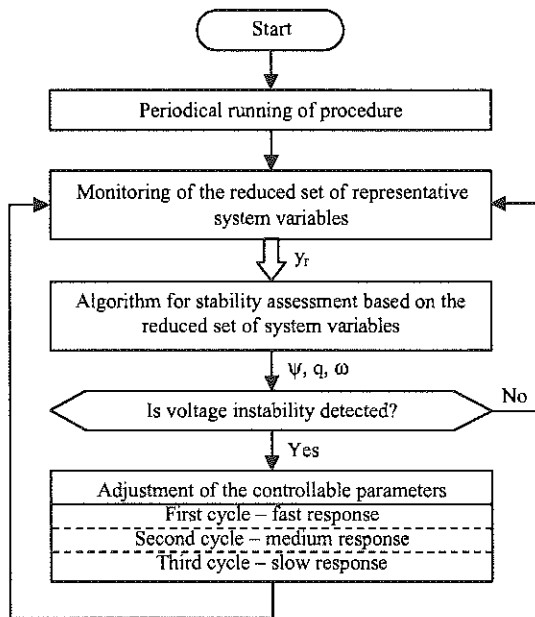


Fig. 6. Algorithm for on-line preventing of voltage stability

### 3. 2. Time decomposition of controllable system's devices

In the Table I there are given all the considered control devices, their time response, controllable parameters, as well as the regulation domain where such device operates. The following controllable system's devices are considered: FACTS devices (static VAR compensators and phase shifters), automatic voltage regulators of generators, power system stabilizers, capacitor banks and transformers with under load type changer with and without phase shifting and under voltage and under frequency relays. All of the above devices have different available variation ranges of corresponding controllable parameters and its control time response is in Table I. All control devices above are divided by response time in three groups (Fig. 7):

- 1) Control devices with fast response.
- 2) Control of devices with medium response.
- 3) Control adjustments of devices with slow response.

In control devices with fast response belong succeeding devices with very fast response: FACTS devices (static VAR compensators and phase shifters) and under-voltage relays. Their time parameters are in the level with a couple of hundredths of milliseconds. Practically, phase shifters have dominant influence to the global system angle stability, while static VAR systems and under-voltage relays have dominant influence to the local voltage stability.

In control devices with medium response belong following devices with medium speed response: AVR of generators, PSS and under-frequency relays, AVR of generator and under-voltage relays have dominant local influence to the voltage stability, while PSS and under-frequency relays have dominant influence to the system angle stability. Finally, in control devices with relatively slow response belong capacitor banks and under load tap

changer transformers with and without phase shifting. Fixed capacitor banks and under load tap changer have dominant local influence to voltage stability while under load tap changer with phase shifting have dominant influence to system angle stability.

Table I - Time response of control devices

| Type of control devices                                              | Time response                      | Controllable parameters                               | Level   |
|----------------------------------------------------------------------|------------------------------------|-------------------------------------------------------|---------|
| Automatic voltage regulator of generator (AVR)                       | 10÷100ms                           | Voltage set point                                     | Local   |
| FACTS devices - Thyristor controlled phase - angle regulator (TCPAR) | 20÷100ms                           | Voltage angle phase shift                             | Local   |
| FACTS devices - Static VAR compensators (SVC)                        | 50÷100ms                           | Injected reactive power                               | Local   |
| Under-voltage relays (UVR)                                           | ≈100ms                             | Load shed in corresponding degree                     | Local   |
| Mechanically switched capacitor (MSC)                                | ≈100ms                             | Reactance                                             | Local   |
| Under-frequency relays (UFR)                                         | Less then 1s                       | Load shed in corresponding degree 49.6, 49.2, 48.8 Hz | Overall |
| Power system stabilizer (PSS)                                        | 1÷10s                              | Gain and time constant                                | Overall |
| Fixed capacitor bank (FCB)                                           | 10÷60s                             | Capacity                                              | Local   |
| Under load tap changing transformers (ULTC)                          | 60s+10÷20s for each regulation tap | Tap position                                          | Local   |
| Under load tap changing transformers with phase shifting (ULTCPS)    | 60s+10÷20s for each regulation tap | Tap position                                          | Local   |

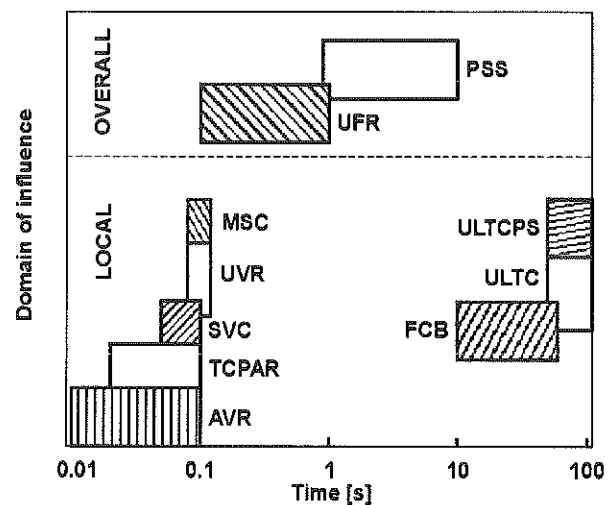


Fig. 7. Time decomposition of controllable system's devices

Using the suggested methodology, clearly there is an open space for coordination of use of controllable resources, in attempt to prevent the process of instability in real-time.

### 3.3. Coordination of adjustments

An appropriate coordination of adjustment of the above control devices is recommended for prevention of instability process, it being based on time decomposition of influences of all mentioned control devices (being their controllable parameters). In the first cycle after detection of instability, readjustment is performed for parameters of control devices with fast response (equation 6 and 7).

$$\Delta s^i = \begin{bmatrix} q_1 & q_2 & \dots & q_i & \dots & q_n \end{bmatrix} \times \begin{bmatrix} p_1^i \\ p_2^i \\ \vdots \\ p_i^i \\ \vdots \\ p_n^i \end{bmatrix} \quad (6)$$

$$\Delta M^i = \begin{bmatrix} m_1 & m_2 & \dots & m_i & \dots & m_n \end{bmatrix} \times \begin{bmatrix} p_1^i \\ p_2^i \\ \vdots \\ p_i^i \\ \vdots \\ p_n^i \end{bmatrix} \quad (7)$$

where are:

$\Delta s^i$  - expected change of the critical mode in the first regulation step,

$\Delta M^i$  - expected change of margin stability in the first regulation step,

$q_i$  - sensitivity coefficient of the variation of the critical mode respecting the change of parameter "i" value

$m_i$  - sensitivity coefficient of the variation of stability margin respecting the change of parameter "i" value.

In this process arrangement is performed on only those parameters that have corresponding impact on variation of the unstable modes. By appropriate influence are expected those control devices that have parameter influence to the change of the critical value higher than the specified value that is determined in off-line analysis. In equation 6 and 7 those parameters are marked with "2" and "i". Finally, by summing up the appropriate terms it is obtained the expected value of the critical mode change, being the margin stability after this regulation step (equations 8 and 9).

$$\Delta s^i = \sum_{i=1}^N q_i p_i^i = q_2 p_2^i + q_i p_i^i \quad (8)$$

$$\Delta M^i = \sum_{i=1}^N m_i p_i^i = m_2 p_2^i + m_i p_i^i \quad (9)$$

If it is estimated that after this regulation step change of the critical eigenvalue (stability margin) would be insufficient, that it would not be detected damping if unstable modes, it moves to the second regulation step - the third one.

## 4. Application

The proposed methodology for on-line monitoring and preventing of voltage instability was tested on the eastern part of the high-voltage power system of former Yugoslavia, which has 92 buses, 12 generator buses and 174 lines (Fig.8).

### 4.1. Test results of comparative analysis of algorithms for on-line monitoring

The proposed methodology for stability analysis which is based on ANNs with complete and reduced sets of input data was tested on the eastern part of the high-voltage power system of former Yugoslavia which has 92 buses, 12 equivalenced generator buses and 174 lines. In doing so the following four cases were considered for the complete input vector of system variables:

- 1) vector  $y=(\theta, V)$ , system state variables;
- 2) vector  $y=(P, Q)$ , directly measurable system variables;
- 3) vector  $y=(V, P, Q)$ , directly measurable system variables;
- 4) vector  $y=(\theta, V, P, Q)$ , all system variables.

By combining these input vectors with the proposed algorithm for detecting the topology NT and monitoring and evaluating voltage stability AY and AR, the following configurations/algorithms are obtained which are tested in this paper: NT-( $\theta, V$ ), NT-( $P, Q$ ), NT-( $V, P, Q$ ), NT-( $\theta, V, P, Q$ ), AY-( $\theta, V$ ), AY-( $P, Q$ ), AY-( $V, P, Q$ ), AY-( $\theta, V, P, Q$ ), AR-( $\theta, V$ ), AR-( $P, Q$ ), AR-( $V, P, Q$ ), AR-( $\theta, V, P, Q$ ). As such, of special interest are the algorithms which are based on the vector of system variables  $y=(V, P, Q)$  which are directly measurable from the system, while the remaining input vectors require estimated values of the sub-vector of the voltage phase angles of the buses ( $\theta$ ).

### 4.2. System reduction and ANN learning on a test sample

The following relevant configurations are considered in this paper: base configuration, all single outages of lines and generators, and most probable combinations of double outages. For each relevant configuration, first the reduced set of system variables is determined using the self-organized neural network UR. This reduction renders the average reduction of the system variable vector by 95%, so that the reduced vector represents only about 5% of the whole vector. In forming these vectors as separate groups, the following are usually set apart:

- 1) Voltage phase angles and magnitudes in buses where low rated power generators are connected;
- 2) Active and reactive powers in generator buses;
- 3) Active and reactive powers in loaded buses of a single region;
- 4) Voltages in load buses of a single compact region.

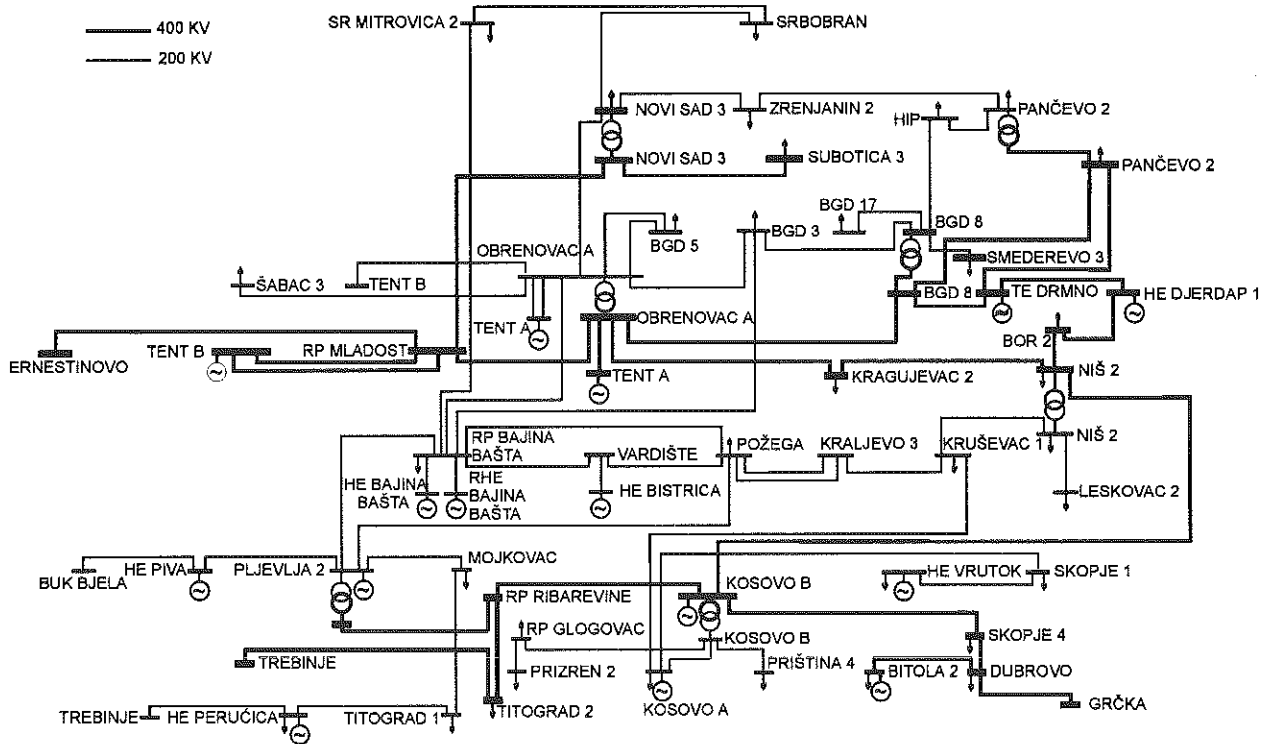


Fig. 8. Single line diagram of consider power system

It is interesting to note that it was actually those buses which would be assigned as pilot buses, according to the secondary voltage regulation algorithm [17], which were chosen as characteristic representatives of the group with the voltages of load buses. In this way, the proposed algorithm for reduction of the system variable set can also be used for selecting a candidate for the pilot buses of secondary voltage regulation.

On the basis of the complete and reduced vectors of system variables, supervised learning of ANNs was carried out. The ANNs were trained: either one network for all relevant configurations (algorithm AY), or a single network for each relevant configuration (algorithm AR). For each relevant configuration, the load was varied over the range of the nighttime minimum to the daytime peak value, during which 100 different margins were observed. The basic characteristics of learning for all considered ANN configurations are presented in Table II.

Table II – Basic learning characteristics of the observed ANNs

| BP performances            | NT     | NY     | NR     |
|----------------------------|--------|--------|--------|
| Momentum constant $\alpha$ | 0.9    | 0.9    | 0.9    |
| Learning rate $\epsilon$   | 0.001  | 0.001  | 0.001  |
| Number of epochs           | 5000   | 31000  | 26000  |
| Mean square error          | 0.0005 | 0.0018 | 0.0010 |

In Table III, the relationship is presented comparatively of the time needed for stability analysis, system reduction and ANN learning for algorithms AY and AR. From the table it can be

seen that the AR algorithm is significantly more efficient in the learning phase. This efficiency is achieved because of the shorter necessary time for calculating the stability analysis for the reduced system model. The other more significant reduction in computer time was achieved in the shorter learning time for several smaller ANNs than for the one large ANN. However, the obstacle is the application of algorithm AR which is necessary for the configuration of the large number of smaller ANNs. This number is approximately equivalent to the number of relevant configurations.

Table III – Comparative computer learning time for algorithms AY i AR

|    | System reduction: NR+AESOPS | Stability analysis | learning stage | Total time |
|----|-----------------------------|--------------------|----------------|------------|
| AY | 0 s                         | 1520 s             | 68 488 s       | 70 008 s   |
| AR | 230 s                       | 678 s              | 15 980 s       | 16 888 s   |

### 4.3 Testing the methodology in exploitation

The testing of ANNs on a real power system was carried out for all configurations for topology detection, and for monitoring and assessing voltage stability margins. Testing of the trained ANNs for the detection of system topology was carried out on an unknown set of 12960 samples (40 each for every topology observed). In doing so, the following four ANNs for topology detection were considered: NT-( $\theta, V$ ), NT-( $P, Q$ ), NT-( $V, P, Q$ ), NT-( $\theta, V, P, Q$ ). On the observed test set, all four networks

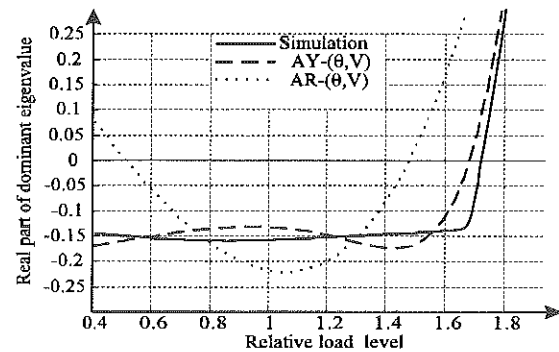
detected all the considered topologies with a high degree of accuracy. Namely, the output neurons of neural network NT were so designed that they give a binary code for each topology considered. The mean square errors calculated from the real values at the output neurons are given in Table IV.

Table IV - Mean square errors for output neurons and for the considered power system topology

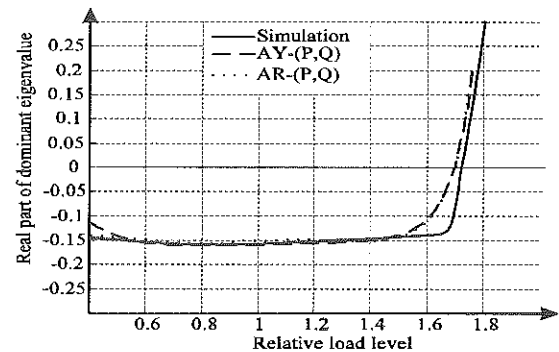
| Considered topology                      | ( $\theta, V$ )      | ( $P, Q$ )           | ( $V, P, Q$ )        | ( $\theta, V, P, Q$ ) |
|------------------------------------------|----------------------|----------------------|----------------------|-----------------------|
| Basic topology                           | $0.74 \cdot 10^{-5}$ | $0.52 \cdot 10^{-5}$ | $0.31 \cdot 10^{-5}$ | $0.14 \cdot 10^{-5}$  |
| Outage on the 3 <sup>rd</sup> line       | $0.82 \cdot 10^{-5}$ | $0.44 \cdot 10^{-5}$ | $0.34 \cdot 10^{-5}$ | $0.22 \cdot 10^{-5}$  |
| Outage on the 12 <sup>th</sup> line      | $0.84 \cdot 10^{-5}$ | $0.30 \cdot 10^{-5}$ | $0.19 \cdot 10^{-5}$ | $0.12 \cdot 10^{-5}$  |
| Average value of all observed topologies | $0.79 \cdot 10^{-5}$ | $0.38 \cdot 10^{-5}$ | $0.30 \cdot 10^{-5}$ | $0.20 \cdot 10^{-5}$  |

The test results of the neural networks for the monitoring and assessment of the voltage stability margin are shown in Fig.9 and Fig.10. In Fig.9 there is a comparative presentation of the dependence of the real part of the critical eigenvalues on the system load level for algorithms AY and AR. In Fig.10 there is a comparative presentation of the dependence of the voltage stability margin on the system load level for algorithms AY and AR. From Fig.9a and Fig.10a, it can be seen that in the situation where the input set contains only system state variables ( $\theta, V$ ), greater precision is achieved by using algorithm AY with the whole input set, than by using algorithm AR with a reduced input set. When the input set consists of input vectors ( $P, Q$ ), the precision achieved with reduced or complete input sets, is almost equal (Fig.9b and Fig.10b). Finally, from Fig.9c, Fig.10c, Fig.9d and Fig.10d, it can be seen that when the input set contains enough data (input vectors: ( $V, P, Q$ ) and ( $\theta, V, P, Q$ ), greater precision is achieved by using algorithm AR with a reduced input set than by using algorithm AY with the entire input set. In addition, algorithm AR is one magnitude faster in exploitation than algorithm AY (in terms of ms), which is exceptionally important because exploitation is done in an on-line environment.

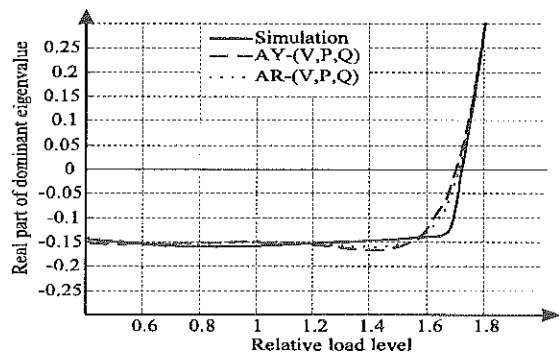
As mentioned above, when assessing voltage stability, both the ISA and DSA approaches were analyzed. The computer times needed for analyzing stability in both approach are given in Table V. From the table it can be seen that the direct calculation of stability using DSA and AR-( $P, Q$ ), decreases computer time remarkably without significant loss in precision.



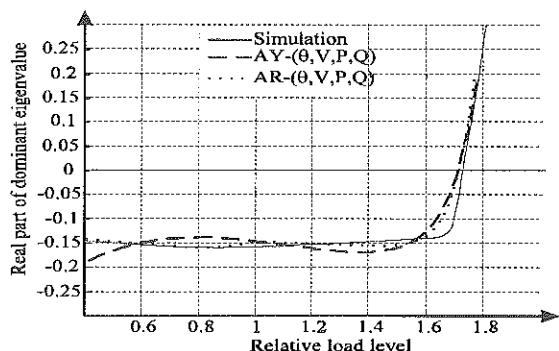
(a) - Algorithms AY-( $\theta, V$ ) and AR-( $\theta, V$ )



(b) - Algorithms AY-( $P, Q$ ) and AR-( $P, Q$ )



(c) - Algorithms AY-( $V, P, Q$ ) and AR-( $V, P, Q$ )



(d) - Algorithms AY-( $\theta, V, P, Q$ ) and AR-( $\theta, V, P, Q$ )

Fig. 9 - Evaluation of the real part of critical eigenvalues for the algorithms AY and AR

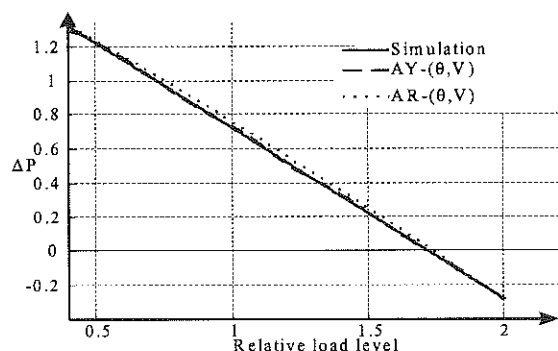
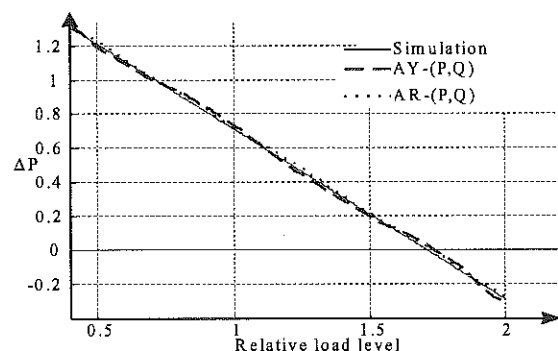
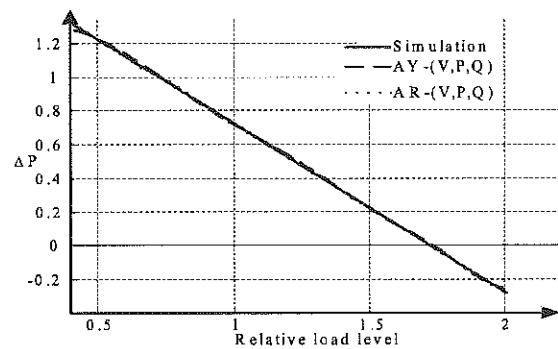
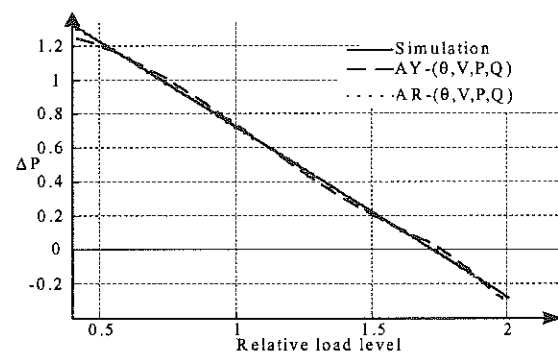
(a) - Algorithms  $AY-(\theta, V)$  and  $AR-(\theta, V)$ (b) - Algorithms  $AY-(P, Q)$  and  $AR-(P, Q)$ (c) - Algorithms  $AY-(V, P, Q)$  and  $AR-(V, P, Q)$ (d) - Algorithms  $AY-(\theta, V, P, Q)$  and  $AR-(\theta, V, P, Q)$ Fig. 10 - Evaluation of the voltage stability margin for the algorithms  $AY$  and  $AR$ 

Table V - Computer times for assessing voltage stability using the indirect approach (ISA) and the direct approach (DSA)

| Algorithm | Fast decoupled load flow calculation | Voltage stability assessment using following input vector: |                       | Total time |
|-----------|--------------------------------------|------------------------------------------------------------|-----------------------|------------|
|           |                                      | $y-(P, Q)$                                                 | $y-(\theta, V, P, Q)$ |            |
| ISA-AY    | 450 s                                | -                                                          | 212 s                 | 662 s      |
| ISA-AR    | 450 s                                | -                                                          | 28 s                  | 478 s      |
| DSA-AY    | -                                    | 145 s                                                      | -                     | 145 s      |
| DSA-AR    | -                                    | 29 s                                                       | -                     | 29 s       |

## 4.4. Algorithm for preventing of voltage instability process

The second part of the analysis is related to simulation of algorithm for on-line preventing of voltage instability. Simulations are performed so that firstly the system is brought to the margin of stability, and then instability is initiated with two cascade contingencies. Then it is simulated the effect of algorithm for monitoring and prevention of voltage instability (Fig.11).

The system is brought to critical operating point by uniform increase of loads. This critical operating point A1 is initially unstable and the Floquet coefficient [17] is equal to  $\beta_2=0.303$ . This means that a small increase of the system load causes the appearance of growing oscillations resulting in a systems breakdown. The bifurcation is sub-critical, i.e. the system can be unstable even before the critical load level is reached. The critical point was also analyzed using the modal analysis applied to the linearized dynamic model. It was proven by the participating factors that the unstable modes can be associated dominantly with voltage phenomena and not with rotor angle phenomena. This means that an incremental disturbance appearing at the critical operating point, in the first instance leads to voltage instability, which is followed by mechanical - rotor angle instability. Dangerous rotor angle oscillations are thus delayed for a certain period of time. Then the operation of the proposed algorithm is simulated for on-line monitoring and preventing of voltage instability. For monitoring of voltage instability is used the most efficient algorithm from the first part - algorithm DSA-AR that is based on reduced set of system variables, while for prevention of voltage instability it is used the proposed on-line algorithm with the following regulation recourses: FACTS devices (SVC, phase shifters), AVR, as well as PSS.

In the critical operating point in the moment  $t=0$  the first contingency is simulated - increase of load in the system for 5MW. From the figure it is obvious that such initial contingency may, if there are not performed any regulation measures, after 23s brings to voltage collapse (Fig.11a). Than the effect of the proposed algorithm for monitoring and preventing is simulated. Instability is detected after 20s (the end of phase I), and then the first algorithm is activated (phase II) in which it is performed rearrangement of very fast FACTS devices (SVC and phase shifters). It is clear now that initially unstable system may stabilize in this way in 26s (Fig.11b).

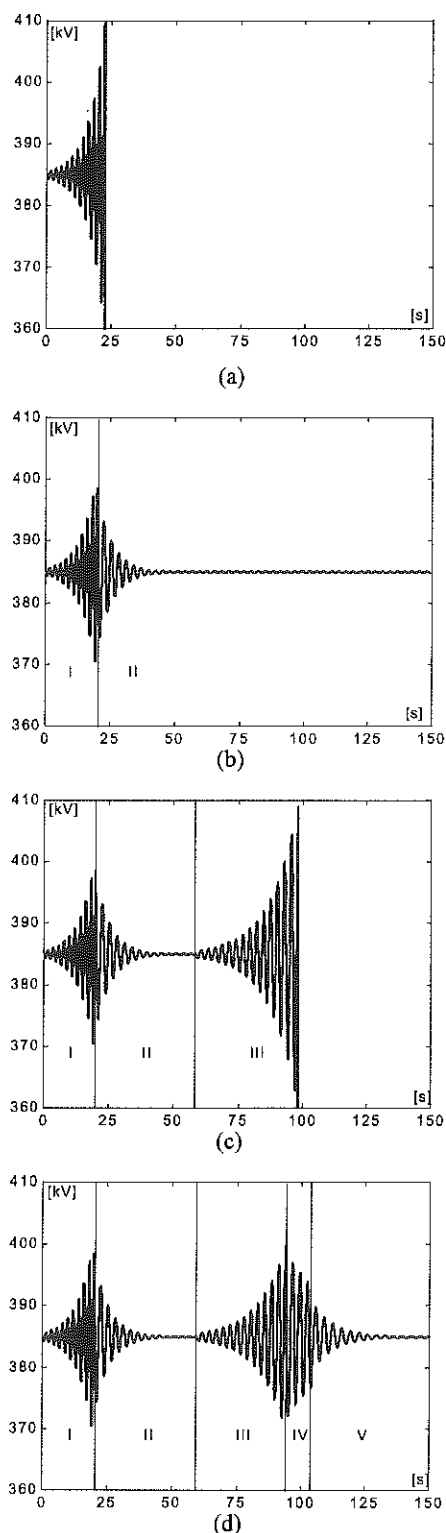


Fig. 11. Voltage variation at the jeopardized critical load bus when the coordinated remedial control measures are used

Therewith, the second cascade contingency is simulated - downfall of the local power generator of 100MW. This contingency is superposed to the first contingency after the  $t=59$ s. If there do not get performed any further control actions, this contingency will produce system breakdown in about 40s (phase III, Fig.11c). However, when the second step is activated (readjustment of AVRs in the phase IV) and the third step (readjustment of PSSs in the phase V), the system is stabilized after 35s (Fig.11d).

The obtained simulation results indicate that using such an integral coordinated approach of emergency control, even after the several cascade disturbances, could bring the system into a stable steady state.

## 5. Conclusion

In this paper an on-line methodology is suggested for monitoring and preventing of voltage instability process. The proposed methodology consists of an algorithm for monitoring and algorithm for preventing of voltage instability process. Algorithm for monitoring is based on neural networks that use reduced set of system variables to detect instability in the system. Outputs from these algorithms are the stability indices of the system and information for which the controllable system parameters have dominant influence to dump of unstable modes. Algorithm for preventing of voltage instability process is based on results from the monitoring algorithm. Basically, by this algorithm controllable system parameters that have dominant influence to dump of unstable modes are readjusted. This readjustment is performed in three steps, that are time-divided by the velocity of response of the used regulation resources. Establishment of these on-line centralized algorithms provides a more efficient coordination of available regulation resources and better use of available capacities in the system in conditions when system is heavy loaded.

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#### Appendix A

The basic model for system reduction is a linearized mathematical model of power system:

$$\dot{x} = Ax + By, \quad (A1)$$

$$0 = Cx - Dy. \quad (A2)$$

If the vector of state  $x$  is divided into two sub-vectors:  $x_R$  (the sub-vector which contains the variables of the state whose dynamics are under consideration) and  $x_O$  (the sub-vector which contains the variables of the state whose dynamics are not under consideration), the equations above obtain the following form:

$$\dot{x}_R = A_{RR}x_R + A_{RO}x_O + B_R \cdot y, \quad (A3)$$

$$\dot{x}_O = A_{OR}x_R + A_{OO}x_O + B_O \cdot y, \quad (A4)$$

$$0 = C_Rx_R + C_Ox_O + D \cdot y, \quad (A5)$$

where:

$A_{RR}$ ,  $A_{RO}$ ,  $A_{OR}$ ,  $A_{OO}$ , correspond to the sub-matrix of matrix  $A$ ,

$B_R$ ,  $B_O$  correspond to the sub-matrix of matrix  $B$ ,

$C_R$ ,  $C_O$  correspond to the sub-matrix of matrix  $C$ .

That is, the system of equations (A3)-(A5) in the Laplace frequency domain state:

$$s x_R = A_{RR}x_R + A_{RO}x_O + B_R \cdot y, \quad (A6)$$

$$s x_O = A_{OR}x_R + A_{OO}x_O + B_O \cdot y, \quad (A7)$$

$$0 = C_Rx_R + C_Ox_O + D \cdot y. \quad (A8)$$

In order to observe the dynamics of only relevant state

variables which are contained in sub-vector  $x_R$ , it is necessary to eliminate the sub-vector of variables of state  $x_O$  from models (A6)-(A8), and the vector of algebraic variable  $y$ . After these elimination, which are realized using the Gauss method, a reduced system model is obtained:

$$s\mathbf{x} = [\mathbf{A}_{RR} - \mathbf{B}'\mathbf{D}^{-1}(s)\mathbf{C}]\mathbf{x}_R, \quad (\text{A9})$$

where the following symbols are used:

$$\mathbf{B}' = [\mathbf{A}_{RO} \quad \mathbf{B}_R], \quad \mathbf{D}'(s) = \begin{bmatrix} \mathbf{A}_{RR} - s\mathbf{I} & \mathbf{B}_O \\ \mathbf{C}_O & \mathbf{D} \end{bmatrix},$$

$$\mathbf{C}' = \begin{bmatrix} \mathbf{A}_{OR} \\ \mathbf{C}_R \end{bmatrix}, \quad (\text{A10})$$

For analyzing the dynamic of the reduced model (A9), it is necessary to determine its eigenvalues. Determining these eigenvalues is done by an iterative approach: 1) individual or 2) simultaneous [5].

In this paper the individual method is used. This method is based on the following iterative approach:

$$s_{k+1} = \mathbf{A}_{ii} - \mathbf{B}'\mathbf{D}^{-1}(s_k)\mathbf{C}', \quad k=1,2,\dots, \quad (\text{A11})$$

where:

$s_k, s_{k+1}$  - the approximation of the sought eigenvalues in the (k) and (k+1) iteration.

For improving the convergence of these iterative methods, product linearization  $\mathbf{B}'\mathbf{D}^{-1}(s_k)$  is used, as proposed in Ref. [15].

With this iterative method, the eigenvalue is determined which is predominantly associated to the  $i$ -th component of the sub-vector of variables of state  $x_R$ . By varying the index  $i=1,\dots,R$  it is possible to determine all eigenvalues of the reduced model (A9) with great efficiency.

## Appendix B

For small-signal stability studies, non linear equations describing actual dynamic system are linearized around operating point, and model can be expressed by linear approximation:

$$\Delta \dot{\mathbf{x}} = \mathbf{A} \Delta \mathbf{x} \quad (\text{B1})$$

Where  $\mathbf{A}$  is the state matrix of the linearized model of the system, and  $\Delta \mathbf{x}$  is the state vector of linearized system

The state vector  $\Delta \mathbf{x}$  of linearized system model can be transformed into a new state vector  $\mathbf{z}$  using the linear transformation:

$$\Delta \mathbf{x}(t) = \mathbf{W} \mathbf{z}(t) \quad (\text{B2})$$

Where:

$\mathbf{W} = [\mathbf{w}_1, \mathbf{w}_2, \dots, \mathbf{w}_n]$  is a square matrix whose columns are the eigenvectors of the state matrix of the system;

$\mathbf{z} = [z_1, z_2, \dots, z_n]$  is a vector modes or mode functions of the linear model of the system.

Equation (B2) shows that each state variable is a linear combinations of all the modes:

$$\Delta x_i(t) = w_{i1}z_1(t) + w_{i2}z_2(t) + \dots + w_{in}z_n(t), \quad i=1,2,\dots,n. \quad (\text{B3})$$

If the eigenvectors are normalized then the factors  $w_{ij}$  determine the relative activity of the state variable  $\Delta x_i(t)$  when particular mode  $z_j(t)$  is excited. From (B2) can be derived:

$$\mathbf{z}(t) = \mathbf{W}^{-1} \Delta \mathbf{x}(t); \quad (\text{B4})$$

which, denoting  $\mathbf{U} = \mathbf{W}^{-1}$ , can be written as:

$$\mathbf{z}(t) = \mathbf{U} \Delta \mathbf{x}(t). \quad (\text{B5})$$

For individual modes equation (B5) gives:

$$z_i(t) = u_{i1}\Delta x_1(t) + u_{i2}\Delta x_2(t) + \dots + u_{in}\Delta x_n(t), \quad i=1,2,\dots,n. \quad (\text{B6})$$

In this case factors  $u_{ij}$  measure the amount of activity a particular state variable  $\Delta x_j(t)$  contributes to a particular mode  $z_i(t)$ .

A knowledge of the matrices  $\mathbf{W}$  and  $\mathbf{U}$  allows the sensitivity of a particular mode  $z_i(t)$  to the changes in a particular system parameter to be determined. This is of particular importance when establishing the parameter settings of any control device installed in the system. Such a sensitivity analysis is accomplished in the following way. Let the  $w_i$  be a column of matrix  $\mathbf{W}$  and  $u_i^T$  be a row of the matrix  $\mathbf{U}$  then it holds that:

$$\mathbf{A} \mathbf{w}_i = \lambda_i \mathbf{w}_i \quad (\text{B7})$$

$$\mathbf{u}_i^T \mathbf{A} = \lambda_i \mathbf{u}_i^T \quad (\text{B8})$$

where:

$\mathbf{A} = \text{diag}[\lambda_1, \lambda_2, \dots, \lambda_n]$  - is the matrix of the eigenvalues of the matrix  $\mathbf{A}$ ;

$\mathbf{w}_i$  - is the right eigenvector;

$\mathbf{u}_i$  - is the left eigenvector.

Based on equations (B7) and (B8) it can be written:

$$\mathbf{u}_i^T \mathbf{A} \mathbf{w}_i = \mathbf{u}_i^T \lambda_i \mathbf{w}_i \quad (\text{B9})$$

$$\lambda_i = \frac{\mathbf{u}_i^T \mathbf{A} \mathbf{w}_i}{\mathbf{u}_i^T \mathbf{w}_i} \quad (\text{B10})$$

Now let  $\xi$  be a system parameter, when, using equation (B10), it can be shown that:

$$\frac{\partial \lambda_i}{\partial \xi} = \frac{\mathbf{u}_i^T \left( \frac{\partial \mathbf{A}}{\partial \xi} \mathbf{w}_i \right)}{\mathbf{u}_i^T \mathbf{w}_i}. \quad (\text{B11})$$

If in the system exists  $r$  parameters which value can vary  $[\xi_1, \xi_2, \dots, \xi_r]$  influence to the system eigenvalues can be expressed by:

$$\Delta \lambda_i = \frac{\mathbf{u}_i^T}{\mathbf{u}_i^T \mathbf{w}_i} \left[ \frac{\partial \mathbf{A}}{\partial \xi_1} \mathbf{w}_i \frac{\partial \mathbf{A}}{\partial \xi_2} \mathbf{w}_i \dots \frac{\partial \mathbf{A}}{\partial \xi_r} \mathbf{w}_i \right] \begin{bmatrix} \Delta \xi_1 \\ \Delta \xi_2 \\ \vdots \\ \Delta \xi_r \end{bmatrix} \quad (\text{B12})$$

For all eigenvalues equation (B12) can be expanded:

$$\begin{bmatrix} \Delta\lambda_1 \\ \Delta\lambda_2 \\ \vdots \\ \Delta\lambda_n \end{bmatrix} = \begin{bmatrix} \frac{\mathbf{u}_1^T}{\mathbf{u}_1^T \mathbf{w}_1} \frac{\partial \mathbf{A}}{\partial \xi_1} \mathbf{w}_1 & \frac{\mathbf{u}_1^T}{\mathbf{u}_1^T \mathbf{w}_1} \frac{\partial \mathbf{A}}{\partial \xi_2} \mathbf{w}_1 & \dots & \frac{\mathbf{u}_1^T}{\mathbf{u}_1^T \mathbf{w}_1} \frac{\partial \mathbf{A}}{\partial \xi_x} \mathbf{w}_1 \\ \frac{\mathbf{u}_2^T}{\mathbf{u}_2^T \mathbf{w}_2} \frac{\partial \mathbf{A}}{\partial \xi_1} \mathbf{w}_2 & \frac{\mathbf{u}_2^T}{\mathbf{u}_2^T \mathbf{w}_2} \frac{\partial \mathbf{A}}{\partial \xi_2} \mathbf{w}_2 & \dots & \frac{\mathbf{u}_2^T}{\mathbf{u}_2^T \mathbf{w}_2} \frac{\partial \mathbf{A}}{\partial \xi_x} \mathbf{w}_2 \\ \vdots & \vdots & \ddots & \vdots \\ \frac{\mathbf{u}_n^T}{\mathbf{u}_n^T \mathbf{w}_n} \frac{\partial \mathbf{A}}{\partial \xi_1} \mathbf{w}_n & \frac{\mathbf{u}_n^T}{\mathbf{u}_n^T \mathbf{w}_n} \frac{\partial \mathbf{A}}{\partial \xi_2} \mathbf{w}_n & \dots & \frac{\mathbf{u}_n^T}{\mathbf{u}_n^T \mathbf{w}_n} \frac{\partial \mathbf{A}}{\partial \xi_x} \mathbf{w}_n \end{bmatrix} \begin{bmatrix} \Delta\xi_1 \\ \Delta\xi_2 \\ \vdots \\ \Delta\xi_x \end{bmatrix} \quad (\text{B13})$$

For many system parameters the elements of the state matrix  $\mathbf{A}$  are simple functions and the determination of the matrix of derivatives  $\partial\mathbf{A}/\partial\mathbf{q}$  presents little problem. This is especially true with regard to the parameters of the excitation and voltage control systems. Knowing the value of the derivative  $\partial\mathbf{A}/\partial\xi$  it is possible to determine which parameters may improve the system stability by observing if the system eigenvalues move to the left on the complex plane

## On-line Estimation of Power System Security Limits

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### Abstract

This paper proposes a fast pattern matching technique using Artificial Neural Networks that takes advantage of the off-line studies to accurately estimate security limits on-line. The precise methodology of operation planners is followed to establish the limits used to train the networks. A hierarchical design combining margin estimators for different security criteria and operating conditions is developed. Here this framework is applied to dynamic security.

### 1. Introduction

In the deregulated environment, determining the system operational limits has become increasingly important. In current practice, operational planners employ detailed power system studies to find the maximum allowable loadings in particular areas and the associated transfers across key interfaces. Reliability standards require that the system withstand any credible contingency and furthermore, must be operated with some security margin to allow operators the possibility of responding to events. Under this approach, the system ratings tend to be conservative, as studies are based on highly stressed conditions and incomplete, as the studies cannot analyze all combinations of loading and equipment out-of-service. This paper proposes a fast pattern matching technique using Artificial Neural Networks (ANNs) that takes advantage of the off-line studies to accurately estimate security limits on-line.

Generally speaking, each operational planning study must look at static, dynamic and voltage security concerns. For a given loading condition and the status of any significant equipment out-of-service, response to all credible and major contingencies is investigated. The loading or other key system parameter (KSP) is varied to determine the proximity, or margin, to a security problem. For example in voltage security assessment, one may employ P-V and/or V-Q curves [1] with the distance to the nose representing the margin. The allowable margins and associated reliability criteria are based on the regional council guidelines, e.g., [2]. Margins for each scenario can be determined and documented in look-up tables or nomograms. The operator will then base the real time decisions on this information. Look-up tables have the obvious drawback of inflexibility and are prone to errors, as operators must search for the relevant scenario in the tables.

Nomograms on the other hand provide slightly greater flexibility as they depict trade-offs in operating conditions, for example between some loading condition and a transfer across a key interface. Still, nomograms fail to fully capture all the information contained in the off-line studies and moreover lack the ability to manage more varied situations. Note this practical approach differs significantly from much of the on-line security literature. Those approaches focus on contingency screening and fast methods for calculating the security. While in practice, the security limits are tabulated off-line as described above.

In recent years, there have been several ANNs based methods introduced for finding security limits [e.g., 3-4]. The essential idea is to select a set of representative features, say line flows, loads, generator limits and so on, and train the ANN on simulation data so that one can estimate the security margin. The ANN is expected to interpolate or generalize to similar unstudied cases. The problem with much of this previous work is that researchers have focused on generic power system models that ignore the practical difficulties in determining these limits. Our earlier work has shown that accurate estimates can be obtained for voltage security on practical systems, specifically, the WSCC system [5], only by developing very narrowly focused estimators. For example, different ANNs need to be trained based on specific major equipment outages and security criteria.

In this paper, this early framework is extended to other security considerations. A hierarchical design combining margin estimators for different security criteria and operating conditions is developed. A voting mechanism is introduced that combines individual ANN estimates. Each ANN is designed using statistical criteria that ensure optimal performance [6]. Numerical examples show the viability of the approach.

### 2. Background

#### 2.1 Operational Planning and Reliability Policies

System security depends on the cooperation of different interconnected entities to coordinate operation of the system. The primary method to ensure this coordination in practice is to establish precise guidelines for the allowable effects neighboring systems may have upon each other. These

guidelines are based on both field experience and extensive operational studies. Different performance levels are used depending on the type of disturbance. For example under WSCC guidelines, allowable post transient voltage deviation is 5% for a single generator outage and 10% for the outage of two generators. Thus, each reliability criteria depends on the type of disturbance. The disturbance should not violate constraints on:

- loading within emergency equipment ratings,
- transient voltage dip both in percentage deviation and in time duration,
- minimum transient frequency,
- post transient voltage deviation,
- positive damping, i.e., stability.

Operation planners generally address these criteria through detailed time domain simulation studies for different loading conditions and all major contingencies. In addition, there may be further requirements on running system studies. In the WSCC, this includes using both the P-V method (MW margin) and V-Q method (MVar margin) to determine an adequate voltage security margin. System operators, to greater or lesser degree depending on the utility, tend to rely heavily on the limits identified by operational planners and make relatively limited use of on-line security tools.

For on-line static security analysis, modern computational speeds allow load flow studies of a large number of contingencies in near real-time. Such software is a standard component of the energy management system (EMS), although it should be noted that this software usually does not directly compute a security margin. On-line dynamic security has focused on using fast methods to quickly determine system stability including both time-domain simulation for transient stability indices and various energy function based methods. This in sharp contrast to the comprehensive, detailed and time-consuming studies employed in operational planning. Voltage security has been based primarily on static or pseudo-dynamic methods.

## 2.2 Remarks

In order to bridge the gap between the practical procedures employed to determine power system interface limits and the various proposed methods for on-line security, we note the following should be considered:

- Operational planning methods cannot identify all possible operating conditions that may arise and are generally too slow to repeat on-line when unstudied system conditions arise.
- Operators do not have full access to all the detailed assumptions that might have been used in an off-line study. Further, they only have access to the

conclusions of a study, i.e., the actual transfer limit and limiting outage, and not all the underlying case studies that might have been performed.

- Many of the proposed on-line security methods are fast methods to determine security but are not as effective at determining a practical operating limit, say, the transfer between systems.
- The various proposed on-line security methods work well under certain conditions but will fail at other times that may not be well-understood.
- Most of the on-line security methods do not base assessment on the detailed reliability requirements employed by the various regional councils.
- Practical system security assessment always has a certain degree of system specific considerations that do not lend themselves to more formal analysis.

In the following, a framework is introduced to address these concerns and to take advantage of the benefits of both approaches.

## 3. Real-time Security Framework

### 3.1 Proposed Security Analysis Approach

The primary method to take better advantage of the off-line operational studies is to form a type of associative memory. That is, each of the studies cases is recorded in terms of the system conditions and the estimated security margin.

Our earlier studies have shown the following [5]:

- Simple linear regression models cannot accurately estimate the security margin.
- Feedforward ANNs have the best understood design criteria and for this type of estimation problem display the most favorable performance.
- No single estimator appears to be workable across a variety of security indices or widely different network topologies regardless of the number of study cases.
- A family of smaller ANNs with different network parameters whose estimates are combined through a voting mechanism will perform better than a single large ANN.

We propose then several layers to the on-line estimation of security limits. At the highest level, the current state and major equipment outages are used to identify the appropriate set of margin estimators. This is depicted in Fig. 1. The set of estimators includes different estimators for different topologies, this means not necessarily a separate estimator for each outage scenario but say an estimator which represents the base case, a wide range of operating conditions and includes the possibility of one or possibly two major

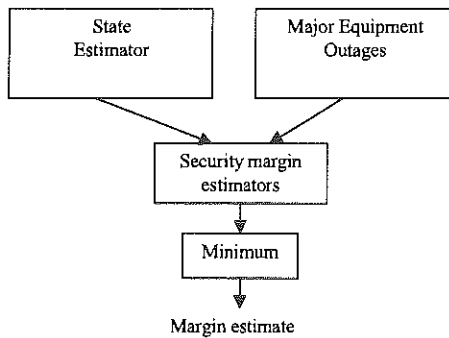


Fig. 1 Overall security margin estimation

equipment outages. This is in addition to the fact that the margin itself includes consideration of all contingencies. This is emphasized graphically in Fig. 2. At the lowest level, a family of ANNs is used to estimate the security margin for a specific security criterion and operating condition. The structure of an estimator for a given set of operating conditions and a specific security criterion is shown in Fig. 3.

### 3.2 Operating Planning Studies

For each of the system performance criteria identified in section 2.1, the limits of the power system operation are established. This may be total load in an area, interface transfer limit or some other KSP. Starting from a base case, a set of relevant system variables is recorded and a full analysis of all major contingencies performed. The KSP is incremented and the analysis repeated until the limits of the system is identified. Thus for each performance criterion, there is a large set of studies that establish the operating limit and a correspondingly large set of variables describing the operating conditions.

### 3.3 Estimator Design

A feedforward ANN based on the Levenberg-Marquardt algorithm is used [6]. There are five primary considerations in design of the neural networks.

**3.3.1 Feature selection.** Selected features should be based on engineering knowledge and statistical correlation coefficients between the selected features and the computed security margins computed from security studies. These will typically be variables such as: real and reactive power flow, reactive power reserve, voltage levels, and so on. A large set of features can be selected and then reduced based on the correlation coefficients.

**3.3.2 Principal component analysis.** Principal component analysis (PCA) assesses the independence of the features in the selected feature set. This is in essence finding an

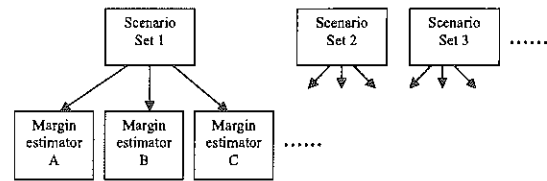


Fig. 2 Hierarchical structure of security margin estimators

orthogonal set of features to present to the estimator, improving both training time and accuracy. For example the P-V margin estimator for the WSCC system [5], the 106 system variables were reduced to 46 for training.

**3.3.3 Hidden layers.** Generally, multiple hidden layers will improve the approximation process and thus, two hidden layers are needed when finding estimates for larger systems with more complicated non-linearities.

**3.3.4 ANN nodes and voting scheme.** The number of nodes in the hidden layers significantly impact the performance. In the Bayesian framework of MacKay [7], the parameters are then estimated using statistical techniques. Here, several ANNs with parameters near the determined optima are trained. The estimates from these networks can be combined using a voting scheme. For example, one effective method is to disregard the lowest and largest margin estimates from such a set of networks and then average the remaining estimates.

**3.3.5 Splitting training data for estimation and validation.** A statistical theory of the overfitting phenomenon that may occur with ANNs is presented in [8]. If  $N$  is the size of the training set and  $W$  is the number of free parameters in the network with  $N < W$ , the optimum split of the training data between estimation and validation subsets is given by

$$r_{opt} = 1 - \frac{\sqrt{2W-1}-1}{2(W-1)} \quad (1)$$

where  $r_{opt}$  is the fraction to be used for training.

## 4. Numerical Examples

The proposed methodology has also been successfully applied to estimate the transfer limits on the WSCC system using a static method, P-V curves, to determine voltage security limits [5]. Here the examples are presented for dynamic events that satisfy the WSCC disturbance criteria for performance level A [2]. The performance of is demonstrated here using the New England 39-bus system. The system has been modified to represent a system with different zones and critical interfaces. Figure 4 shows a load center of buses 17,18 and 27 with three tie lines 3-18, 16-17 and 26-27. The total system loading for the base case is 6150.5 MW and 1658.90 Mvar . The flow

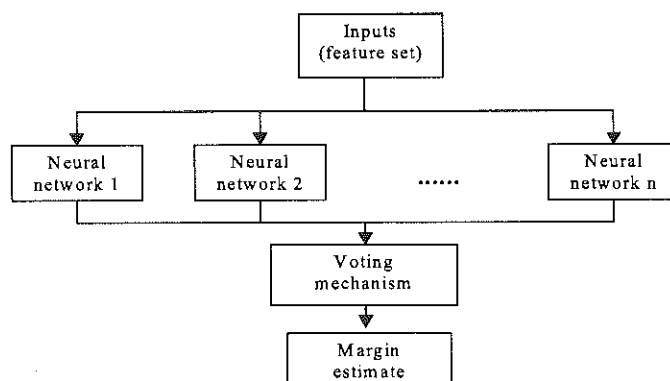


Fig. 3 Individual estimators with voting mechanism

across the interface of this load center is the parameter of interest here. Since this is a rather small system, satisfactory performance is obtained here using a simplified estimator of only one ANN.

To determine the security limits, detailed time domain studies are for each contingency under increasingly heavily loaded conditions. The transfer is incremented in 400 MW blocks and the point at which a performance criterion fails for a given contingency determines the transfer limit. This rather rough estimate of the transfer limit serves for demonstration purposes here but obviously would require more refinement for a practical system. Real and reactive power flows in the network are used to form the initial feature set. A line outage is represented by an arbitrarily large line flow in that line.

#### 4.1 Voltage Instability

The first performance criteria considered is voltage stability as seen by the post-disturbance voltage response. The

maximum voltage dip at any bus following a contingency cannot exceed 25% and a more than 20% dip cannot last for more than 20 cycles. The post-transient voltage dip should not exceed 5%. Finally, there must be positive damping. Note this obviously may overlap with the angle instability criteria.

The designed ANN has a single hidden layer with 10 hidden nodes. There are 131 test cases of which 20% are used for testing. The overall performance is shown in Table 1 and indicates very low percentage errors. Notice also that the combination of PCA and correlation greatly reduces the number of needed features. Figure 5 plots these estimates for the test data.

#### 4.2 Angle Instability

The second performance criteria considered is angular stability. The minimum transient frequency dip at any bus following a contingency cannot exceed 59.6Hz for more than 6 cycles. Again, the system must have positive damping.

The ANN has a single hidden layer with 15 hidden nodes. Again there are 131 test cases of which 20% are used for testing. The overall performance is shown in Table 2 and again there very low percentage errors are seen. Figure 6 plots these estimates for the test data.

### 5. Discussion

This paper proposes an involved framework employing ANNs to estimate on-line security estimates. The primary advantage of the approach is in taking advantage of the numerous detailed off-line studies performed during operations planning. At the same time, it does create an added burden on planners to perform more extensive studies. In previous work, it was established that this methodology will work for practical systems for static security. This work demonstrates the initial stages on estimates for dynamic security. While the results appear promising, the difficulty in implementing these

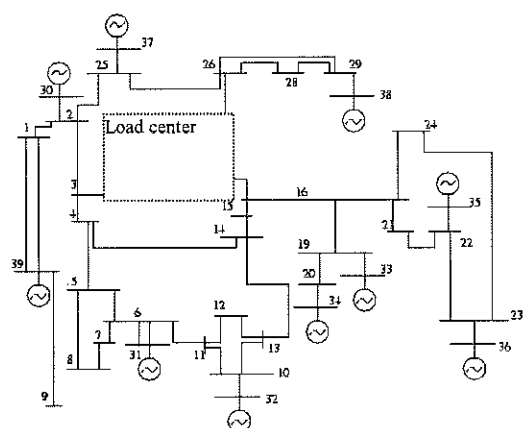


Fig. 4 New England 39 bus system

Table 1 Errors in estimate of voltage security limits

| Max error<br>(MW / %) | Min error<br>(MW / %) | Mean error<br>(MW / %) | Standard<br>Deviation<br>(MW) | Features after<br>PCA | Features after<br>correlation |
|-----------------------|-----------------------|------------------------|-------------------------------|-----------------------|-------------------------------|
| 1.0012 /<br>0.093%    | 0.0062 /<br>0.0015%   | 0.3549 /<br>0.031%     | 0.186                         | 30                    | 4                             |

Table 2 Errors in estimate of angular security limits

| Max error<br>(MW / %) | Min error<br>(MW / %) | Mean error<br>(MW / %) | Standard<br>Deviation<br>(MW) | Features after<br>PCA | Features after<br>correlation |
|-----------------------|-----------------------|------------------------|-------------------------------|-----------------------|-------------------------------|
| 1.9799 /<br>0.25%     | 0.0650 /<br>0.0041%   | 0.4096 /<br>0.060%     | 0.602                         | 32                    | 6                             |

approaches lies in applications for large systems. Larger systems not only contain more complicated non-linearities but also numerous system specific constraints that make application more difficult. Application to the WSCC system is on-going.

Future efforts will also investigate the use of energy function methods and transient stability indices. While these methods have limitations that prevent establishing security limits definitively, by virtue of computational speed they would allow a more extensive set of studies to be carried out for training the ANNs.

#### Acknowledgments

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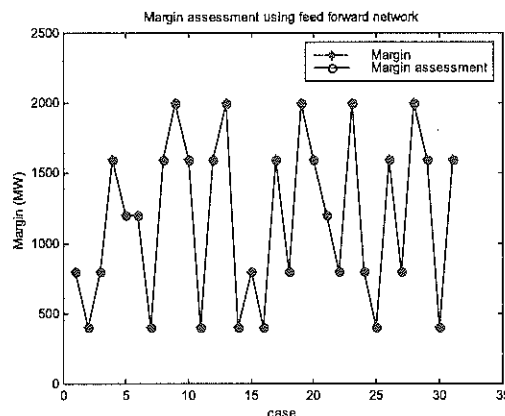


Fig. 5 Margin estimate for voltage stability

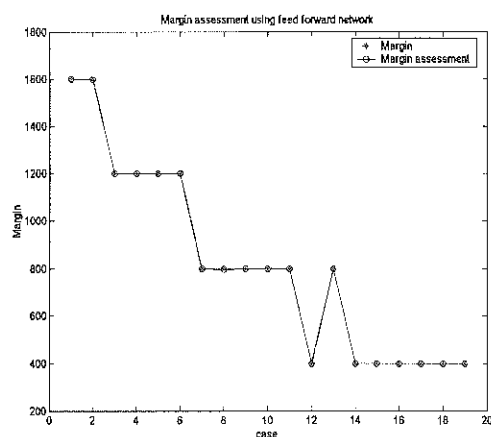


Fig. 6 Margin estimate for angle stability



## A Fast Contingency Analysis by Distributed Parallel Processing

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### Abstract

This paper proposes a fast contingency analysis method for static and voltage security assessment (SSA and VSA) using distributed parallel processing. The proposed method utilizes a sensitivity method based on DC power flow calculation for SSA and an approximation method for generating P-V curve based on continuation power flow (CPFLOW) for VSA. The effectiveness of the proposed method is shown and compared on standard IEEE model systems with promising results.

### Introduction

Evaluation of power system security is obviously very important because the security margin may decrease by cutting back on investments in equipment of power system and acceleration of deregulation for electric power supply in Japan.

Power system security assessment is carried out by contingency analysis. Contingency analysis is performed using a list of contingency cases (single or multiple equipment outage). In practice, since it is required to process power-flow calculation for large number of contingency cases, contingency analysis is time-consuming. The general approach currently and widely adopted is to separate contingency analysis into two distinct stages: contingency selection (screening and ranking), and evaluation. The contingency selection is the process that offers the greatest potential for computational saving, and has received most development effort [1]–[4]. Its purpose is to shorten the original large list of contingencies by eliminating vast majority of cases without violations. It usually utilizes approximate power system computation techniques, to give relatively rapid but limit-accuracy results. Based on these results, the contingency cases are ranked in rough order of severity. Contingency evaluation using detailed analysis is then performed on the reduced number of contingency cases in decreasing order of severity.

Although various methods have been developed for SSA and VSA [1]–[4], they have been concentrated on speedup of the method themselves, and they require further fast computation. in practical environment.

Recently, various researches on distributed parallel processing environment have been done and efficient tools such as MPI (Message Passing Interface) [5]–[7] and PVM (Parallel Virtual Machine) [8] have been developed for scientific computation. Therefore, extreme speedup can be expected using the environment. The proposed method utilizes a network sensitivity method [1] based on DC power flow calculation for SSA and an approximation method (Look-ahead method) [4] for generating P-V curve based on continuation power flow (CPFLOW) for VSA. The proposed method integrates SSA and VSA. The distributed parallel algorithm of the proposed method is based on parallelism of each contingency case. In addition, a dynamic load balance algorithm is integrated. MPI is applied for distributed parallel computation of the proposed method.

The effectiveness of the proposed method is evaluated by simulations using standard IEEE model systems including 14, 30, 57, 118, and 300 bus systems. The results indicate that the proposed distributed parallel processing method is efficient for the speedup of the integration of contingency analysis.

### Network sensitivity method for SSA [1]

The network sensitivity method [1] based on the DC power flow calculation is utilized for SSA. Many possible outage conditions could happen to a power system. In addition, they may cause serious overloads on other equipment. One of the effective ways to provide a quick calculation of possible overloads is to utilize network sensitivity factors. These factors show the approximate change in line flows for changes in generation on the network configuration. In addition, they are derived from DC power flow calculation. The factors can be derived in a variety of ways and basically come down to two types.

- (1) Generation shift factors.
- (2) Line outage distribution factors.

The line outage distribution factors are defined as follows:

$$d_{lk} = \Delta f_l / f_k^0 \quad (1)$$

where,

$l$  and  $k$  : line index,

$d_{ik}$  : line outage distribution factor when monitoring line  $l$  after an outage on line  $k$ ,  
 $\Delta f_l$  : change in megawatt power flow on line  $l$ ,  
 $f_k^0$  : original flow on line  $k$  before it was outaged (opened) .

The generation shift factors have the following definition:

$$a_{ii} = \Delta f_l / \Delta P_i \quad (2)$$

where,

$\Delta f_l$  : change in MW flow on line  $l$  when a change in generation,  $\Delta P_i$ , occurs at bus  $i$ ,

$\Delta P_i$  : change in generation at bus  $i$ .

These factors can be derived from the system equation in the DC power flow as follows:

$$P = B\theta \quad (3)$$

$$\theta = XP$$

where,

$P$  : power,

$\theta$  : phase angle,

$B$  : admittance matrix for DC power flow,

$X$  : the inverse of the submatrix of  $B$  plus a zero row and column corresponding to the reference bus.

Then the line outage distribution factors can be given by

$$d_{ik} = \frac{\frac{x_k}{x_l} (X_{in} - X_{jn} - X_{im} + X_{jm})}{x_k - (X_{nn} + X_{mm} - 2X_{nm})} \quad (4)$$

where,

$x_l$  and  $x_k$  : reactance of line  $l$  and  $k$ ,

$X$  : the matrix of (3),

Subscripts represents element of matrix.

Moreover, the generation shift factors are given by

$$a_{ii} = \frac{1}{x_l} (X_{ni} - X_{mi}) \quad (5)$$

If one knows the power on line  $l$  and line  $k$ , the flow on line  $l$  with line  $k$  out can be determined using the line outage distribution factors.

$$\hat{f}_{l,k} = f_l^0 + d_{lk} f_k^0 \quad (6)$$

where,

$f_l^0, f_k^0$  : preoutage flows on line  $l$  and  $k$ , respectively,

$\hat{f}_{l,k}$  : flow on line  $l$  with line  $k$  out.

If the generator  $i$  is generating  $P_i$  MW and it is lost, the new power flow on each line in the network can be calculated using the generation shift factors.

$$\hat{f}_{l,i} = f_l^0 + a_{li} (-P_i) \quad (7)$$

where,

$\hat{f}_{l,i}$  : flow on line  $l$  after the generator on bus  $i$  fails,

$f_l^0$  : flow on line  $l$  before the failure,

$P_i$  : generation before the failure.

Those "outage flow" on each line can be compared to its limit and those exceeding their limit flagged for alarming. And the stability indices can be defined as follows:

$$K_d = \min_{l=1,2,\dots,L} \left( \frac{P_{lmax} - P_{ld}}{P_{lmax}} \right) \quad (8)$$

where,

$d$  : the case number of contingency cases,

$P_{lmax}$  : the limit of flow on line  $l$ ,

$P_{ld}$  : the outage flow on line  $l$ ,

$L$  : the number of line in the network.

When the stability indices are defined as described above, the contingency with large index value can be evaluated as severe. In addition, overload will be noticed when a positive value is indicated.

Consequently, SSA consists of the following steps:

- Contingency selection (screening and ranking) by the network sensitivity method
- Contingency evaluation by AC power flow calculation
- Development of corrective or preventive strategies

#### Look-ahead method for VSA [4]

The Look-Ahead method [4] based on continuation power flow (CPFLOW) is utilized for VSA in the proposed method. CPFLOW is a dependable and reliable method to generate the P-V curve. In general, the trace of the P-V curve is obtained by a Predictor-Corrector method. Figure 1 shows the concept of the P-V curve generation by CPFLOW. The predictor in Figure 1 is obtained by the given load increase pattern. Then the P-V curve is traced using the enhanced power flow calculation as the corrector. Therefore, time necessary to trace one P-V curve corresponds to tens to hundreds times power flow calculation.

On the other hand, the Look-ahead method only requires one step of Predictor-Corrector method of CPFLOW. The P-V curve is approximated using the quadratic function with only two points (initial and next on step of Predictor-Corrector method) in the Look-Ahead method. As a result, the approximate value of the load limit point can be obtained by approximately two power flow calculations. Figure 2 shows the concept of this technique. The figure shows two P-V curves obtained by CPFLOW and the Look-ahead method. The P-V curve by CPFLOW is obtained in consideration of the control equipment operation.

It is assumed that the power generation or load state is  $P_1$  in a present state ( $X_1$ ) of operation. The next state ( $X_2$ ) is obtained by calculating large step of CPFLOW. The state ( $X_2$ ) is compared with initial state ( $X_1$ ). Then, the load node ( $i$ ) with the most violent voltage descent is selected and the load margin is calculated approximately using the P-V curve on this load node. The approximation can be described by the quadric function as follows:

$$\begin{cases} P_1 = a + bV_{i1} + cV_{i1}^2 \\ P_2 = a + bV_{i2} + cV_{i2}^2 \\ 1 = b\dot{V}_{i2} + 2c\dot{V}_{i2}V_{i2} \end{cases} \quad (9)$$

When the (9) is transformed, it becomes the following:

$$P = c(V_i + \frac{b}{2c})^2 + a - \frac{b^2}{4c^2} \quad (10)$$

In nose-point ( $V_i = -b/2c$ ), there is load margin up to the following.

$$P_{V_{\max}} = a - \frac{b^2}{4c} \quad (11)$$

$V_{i1}, V_{i2}, \dot{V}_{i2}$  in (9) is already obtained, and  $a, b$ , and  $c$  can be calculated. Furthermore, the load margin ( $P_{V_{\max}}$ ) can be calculated by (11). However, this method is a formulation that utilizes the absolute value of  $V$ . If the angle at  $i$ th-node also has a big change, the procedure of the above-mentioned can be applied to the P- $\theta$  curve, and  $P_{\theta_{\max}}$  can be obtained. In this case, the load margin can be obtained as follows:

$$P_{\max} = \frac{1}{2}(P_{V_{\max}} + P_{\theta_{\max}}) \quad (12)$$

When the load margin is obtained as mentioned above, the contingency with small value can be evaluated as severe.

Consequently, VSA consists of the following steps.

- Contingency selection (screening and ranking) by the Look-ahead method
- Contingency evaluation by CPFLOW.
- Development of corrective or preventive strategies

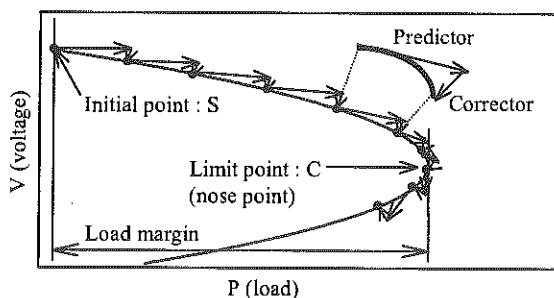


Figure 1. Concept of P-V curve generation by CPFLOW

### Integration of SSA and VSA

Even if SSA and VSA are integrated, they should work respectively as an independent function. In addition, it is necessary to integrate them so that the processing time can be shortened as much as possible.

AC power flow calculation for initial conditions in all contingencies is required in VSA. Therefore, all power flow calculation necessary for contingency evaluation in SSA should be done. The contingency selection in SSA becomes unnecessary and only VSA using the Look-ahead method is required when considering off-line applications. However, it is necessary to evaluate the severe conditions of the target power system as soon as possible for online applications. Therefore, it is necessary to execute the contingency selection in SSA in the on-line application. Thus, The method of integrating is different according to applications.

The proposed method is developed for both online and offline application. The integrated algorithm consists of the following steps.

- Step1. If it is for an online application, go to step2, else go to step 3.
- Step2. Perform the contingency selection (screening and ranking) for SSA by the network sensitivity method.
- Step3. Perform the contingency evaluation for SSA by AC power flow calculation. (including initial power flow calculation for contingency selection for VSA)
- Step4. Perform the initial power flow calculation for contingency selection for VSA by the Look-ahead method. (except the cases calculated in Step3.)
- Step5. Perform the contingency selection for VSA by the Look-ahead method.
- Step6. Contingency evaluation for VSA by CPFLOW.

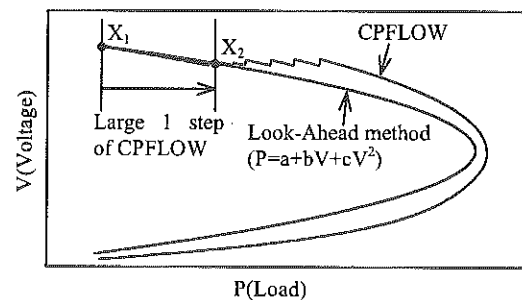


Figure 2. Concept of P-V curve generation by Look-ahead method.

### Application of distributed parallel processing

#### *Distributed parallel processing*

It is important to coordinate the following items in distributed parallel processing: the amount of the inter-processor communication, the calculation load balance, between the process, and grain size of the process. The best selection is different in the architecture of distributed computers and the target problem. In this paper, using the cluster system, which connected several workstations or personal computers, is considered as an application target, and using the network of about 100Mbps, a decentralized and parallel algorithm was examined.

It is assumed to execute the only one process in each computer. In this case, overhead of communication processing for the calculation processing becomes large. Therefore, the process should be coarse-grained and the amount of the communication should be reduced as much as possible. Namely, the proposed method utilizes coarse-grained processes using contingency cases as a basic unit of the problem decomposition. Moreover, the amount of communication can be adjustable in the proposed method. Namely, the proposed method realizes an algorithm in which the communication overlaps with the calculation using non-blocking communication. When data is sent and received, the transmission side does not guarantee that data arrived at the opponent. In the receiving side, the control returns even if data do not arrive. Therefore, all the processing executed in each process becomes the same process in the proposed method and it has an advantage that the program can be shared in all of the computers. In addition, for example, not to make the power flow calculation itself parallel but to make the power flow calculation processing to each contingency in parallel. Therefore, it has an advantage that an existing program and the subroutine can be utilized as it is without major modification.

In the proposed method, MPI (Message Passing interface) [5], which is a standard specification of the message communication library, is utilized as a tool in order to realize decentralized parallel processing. MPICH [6][7], which is an open-source, portable implementation of MPI, is utilized to develop the program using the proposed method. PVM (Parallel Virtual Machine) [8] can be an alternative as such a tool and it is applied to online TSA (Transient Security Analysis) [9]. Recently, however, MPI is becoming a defacto standard tool implemented on many platforms. The developed program using the proposed method can be executed as it is in various environments from the network environment by the personal computer and EWS to the super computer.

#### *Adjustment of calculation load balance*

In the proposed algorithm, when the calculation time of each contingency case is almost the same, the calculation load of each processor can be adjusted according to the number of contingency cases. Therefore, the calculation load can be equalized by making the number of contingency cases distributed to each process even as much as possible for the cluster system with a homogeneous calculation load by the processing performance and other calculation processing etc. As a result, overall calculation time can be shortened. However, the power flow calculation processing may not converge in some contingency cases occasionally. In such a case, the calculation time of each contingency case will vary and the calculation load of each process cannot be equalized. Moreover, when heterogeneous cluster systems or homogeneous cluster systems with different calculation loading conditions because of other process at each computer are connected, it is necessary to determine the number of contingency cases distributed in each computer considering the cluster conditions.

Considering the above observation, the algorithm that can adjust the calculation load adaptively is developed. Concretely, the number of contingency cases distributed to each processor (computer) is adjusted according to the measured calculation time for each contingency case and performance index of each processor, which changes dynamically. The outline of the proposed algorithm is shown as follows. The number of all computers is assumed to be  $n$  and the number of all contingency cases are assumed to be  $N$ .

- Step1.  $S = \sum_{i=1}^n s_i$  where  $s_i$  ( $i=1,2,\dots,n$ ) is the calculation performance index of all processors (computers).
- Step2.  $x=N/S \bmod m$  where  $N$  is the number of all contingency cases.
- Step3. The number of distribution cases to each process is assumed to be  $s_i \times x$ .
- Step4. Sequentially, increase the number of distribution cases from the process with a high performance index until  $m$  becomes zero.
- Step5. Start processing contingency analysis.
- Step6. Each process sets the flag of the distributed contingencies to "under analysis" before the analysis to the contingency cases begins.
- Step7. After the analysis to the contingency case, each process sets the flag of each contingency case to "analysis finished".
- Step8. The process, in which the analysis for all cases ended, checks the flag set in Step6 and 7. If there is a contingency case with the status of "under analysis", the process executes the case with setting a flag as shown in Step6 and 7.

For example, the calculation performance index of each processor can be measured by benchmark test using the common process part which is executed after beginning of the program.

After each process sets the status flag of each case, the flag is transmitted to other processes. When the analysis to the case using each process is ended, it is received. The overhead of the communication is decreased by using no blocking communication, and overlapping communication with the calculation.

### Simulation study

#### Simulation conditions

The effectiveness of the proposed method is evaluated by simulations using IEEE model systems including 14, 30, 57, 118, and 300 bus systems. The execution times are compared with serial processing. The number of severe cases selected by the contingency selection is assumed to 10. The workstation cluster utilizes two (CPU: PentiumII-400Mhz $\times$ 2) or three computers (CPU: PentiumII-300 $\times$ 1,400Mhz $\times$ 2) connected by the network of 100Mbps-Ethernet. The two computers case is corresponding to a homogeneous cluster, and the three computers case is corresponding to a heterogeneous cluster. The compared serial processing programs are executed with the computer of PentiumII-400Mhz. The simulation case condition is as follows:

- Case 1 A decentralized parallel processing is executed without the load balance adjustment on a homogeneous cluster with two computers.  
Case 2 A decentralized parallel processing is executed with the load balance adjustment algorithm on a heterogeneous cluster with three computers.

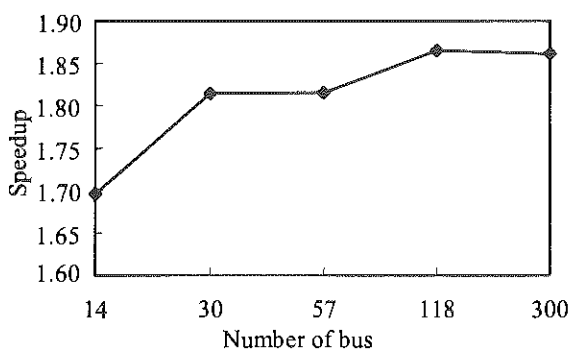


Figure 3. Speedup of the proposed distributed parallel processing on homogeneous cluster environment (2-processor) compared with sequential processing.

#### Simulation results

##### (1) Case 1

The execution time comparison results of the serial processing and the decentralized parallel processing are shown in Figure 3. The load balance adjustment function of the proposed method is not used and the number of contingency cases is distributed evenly in case 1. The proposed distributed parallel program is about 1.86 times faster than the serial processing program in 300 bus real scale power system. The results indicate the effectiveness of the proposed method.

Moreover, according to figure 3, it is observed that the average speedup rate grows as the number of nodes increases. It is confirmed that the ratio of the calculation time to communication time grows as the number of nodes increases. Therefore, the average speedup rate grows as the number of nodes increases because the communication overhead time decreases. In figure 3, the average speedup rate does not increase monotonously as the number of nodes increases. The results can be explained by the following two reasons. Firstly, the number of cases cannot be distributed to each process strictly evenly and it causes imbalance of the calculation load. As a result, the average speedup rate cannot reach to the expected value. Secondly, in some severe contingency cases, the power flow calculation does not converge until the maximum iteration number and the calculation time of the power flow calculation becomes long. In such a case, the calculation time of one CPFLOW calculation can be shortened because the calculation processes after no convergence of load flow are not executed. The possibility that the imbalance of the calculation load among the processes increases in such a case. The results indicate the necessity of adaptive load balance adjustment.

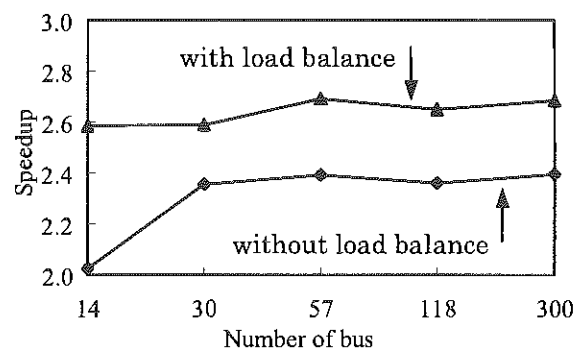


Figure 4. Comparison of speedup for distributed parallel processing on heterogeneous cluster environment (3-processor) with and without load balancing.

## (2) Case 2

The result of case 2 is shown in Figure 4. It can be observed that the average speedup rate with load balance becomes larger than that without load balance. For example, especially for 300 bus real scale powers system, the speedup rate is about 2.68 with load balance and the rate is about 2.39 without load balance. According to the results, the effectiveness of the calculation load balance adjustment function of the proposed method can be confirmed.

Table 1 and Table 2 show the result of the order by the contingency selection in the contingency analysis to the IEEE 300 bus system. Severe faults can be selected by the proposal method for the static voltage contingency analysis.

### Conclusions

This paper presents a fast SSA and VSA integrated contingency analysis method using distributed parallel processing. The distributed parallel processing application technique is proposed using the cluster system on a general workstation platform using MPI, which is a standard specification of the message communication library. The proposed method reduces the overhead of communication processing in each process as much as possible by the overlap processing of the communication. The distributed parallel processing utilizes each contingency case as a process unit and adjusts the calculation load balance autonomously. Using the processing, the proposed method realizes the improvement of efficiency, especially for a fast SSA and VSA integrated contingency analysis. The contingency analysis program by the proposed method is developed and it is verified that the developed program realizes 1.86 times speedup compared with the serial processing using two homogeneous clusters, especially for IEEE 300 bus system. In addition, by using the calculation

load balance adjustment method with heterogeneous clusters with three computers, it is verified that the proposed method realizes 2.68 times speedup compared with the serial processing. The results verify the effectiveness of the proposed calculation load balance adjustment method, especially for the practical IEEE 300 bus system.

As future works, the proposed contingency analysis method will be improved by considering application of other contingency analysis techniques and optimization of parallel computation for realizing fast and reliable computation. By realizing the computation, a practical analytical tool for large-scale power systems will be developed. In addition, it is necessary to examine the fault-tolerant computation of the distributed parallel processing, especially for practical use. Inclusion of the contingency analysis technique for dynamic security assessment is one of the other future works and consequently, a total security assessment tool for practical power systems will be developed.

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Table 1. Results of ranking by static contingency selection for IEEE 300 bus system.

| ranking by detailed analysis | severity factor by detailed analysis | ranking by proposed method | severity factor by proposed method |
|------------------------------|--------------------------------------|----------------------------|------------------------------------|
| 1                            | 0.201                                | 4                          | 0.078                              |
| 2                            | 0.176                                | 2                          | 0.090                              |
| 3                            | 0.150                                | 5                          | 0.060                              |
| 4                            | 0.095                                | 1                          | 0.113                              |
| 5                            | 0.086                                | 3                          | 0.087                              |
| 6                            | 0.078                                | 8                          | 0.021                              |
| 7                            | 0.036                                | 6                          | 0.048                              |
| 8                            | 0.017                                | 7                          | 0.040                              |
| 9                            | -0.013                               | 12                         | -0.059                             |
| 10                           | -0.036                               | 19                         | -0.083                             |

Table 2. Results of ranking by voltage contingency selection for IEEE 300 bus system.

| ranking by detailed analysis | voltage stability by detailed analysis | ranking by proposed method | voltage stability by proposed method |
|------------------------------|----------------------------------------|----------------------------|--------------------------------------|
| 1                            | 0.030                                  | 1                          | 0.024                                |
| 2                            | 0.061                                  | 2                          | 0.060                                |
| 3                            | 0.145                                  | 12                         | 0.345                                |
| 4                            | 0.232                                  | 5                          | 0.197                                |
| 5                            | 0.270                                  | 3                          | 0.126                                |
| 6                            | 0.277                                  | 8                          | 0.327                                |
| 7                            | 0.278                                  | 16                         | 0.424                                |
| 8                            | 0.305                                  | 4                          | 0.183                                |
| 9                            | 0.363                                  | 11                         | 0.344                                |
| 10                           | 0.375                                  | 13                         | 0.346                                |

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## Discussions on Session VI: VOLTAGE SECURITY ASSESSMENT & STATIC SECURITY ASSESSMENT

### Part 1

**Chairman** (D. H. Karlsson): I would like to remind you to clearly state your name when you have a comment or question, this is important for final proceedings.

**S. Iwamoto** (Waseda University): I have a question for Mr. Kulic's presentation as well as to Professor Tomsovic's presentation. I think Mr. Kulic did a very good job. My first question is how did you input, how did you treat the system configuration as input? You just input it like a system configuration 1, 2, or 3? I would like to know how you do that.

**F. J. Kulic**: You're interested in what was the input in the neural network. It was a system variable which consists of active / reactive power, voltage magnitude and phase angles. We fix the load level from 40%, it's some kind of night time minimum, and then increase it in steps of 5, 10%. If for every load, the load calculated the stationary point, we just pick up the data like I said the injected power, powers active / reactive, voltage magnitude, and phase angles. Those are sets for one topology and one load level. We did it for all topologies considered for all levels considered. It is very interesting that for all considered topologies, and all stationary points, there are different input vectors. There are not similar vectors for two different topologies with two different load levels.

**S. Iwamoto**: My point is how did you express the system configuration at the input?

**F. Kulic**: In an earlier stage, I may just, it was a unified Neural network, You want to know how I express the configuration? Yes. It's a queue of 0s and 1s. It was about 400 considered topologies, so I used the queue or vector with the 9 0s and 1s, because the 9 0s and 1s can express 500 combinations. Every topology has its own combination.

**S. Iwamoto**: Ok. The second question is that how did you consider the static capacitor position or the tap setting position, because you mentioned the state of the power system, I understand. You mentioned static capacitor's amount, or tap-setting point, how do you consider them in the approach?

**F. Kulic**: I'm not so sure that I understand your question because I am with the automatic control department and Professor Popovic is not here.

**S. Iwamoto**: Probably Professor Tomsovic could answer

the question.

**K. Tomsovic**: Let me answer your first question on the configuration. In our case, we're considering when we estimated the margin, that margin considers every single contingency. So I don't input any information on the particular topology to the network. I have a family of estimators. I have no discrete input measuring topology. I think the second question was more directed to system. But in terms of what we're using in modeling and control, we are using the static model. We follow the exact same system, whatever they've got as automatic control we've included in our study.

**S. Iwamoto**: My point is that for a specific configuration, the tap changing position or the tap setting position, and static capacitor positions, for the FACTS devices quantity would be different. My question was how to include that kind of FACTS in your system configuration?

**F. Kulic**: Professor Van Cutsem told me they think rearranging of the control devices should change the stationary point of the system.

**S. Iwamoto**: Actually I was asking about the input, I think those contents are missing. That is my point. You see you have expressed the input for the neural nets, like P Q, V magnitude angle, and Y bus information. But the input, as I said, the tap setting position is missing. So my question is have you considered that kind of quantities or not?

**F. Kulic**: I consider how the stationary point was changed when I change some devices. Yes, the neural network is specific because they're very robust, and the changing of stationary point wasn't so big to change the output of the neural network.

**Chairman**: I would like to remind you of the possibility of written contributions, and maybe we can have written contributions from Professor Popovic on this topic.

**D. Koval** (University of Alberta): The question is directed to Professor Van Cutsem. You consider the reactive power input from the loads, particular in line with distributed generators and a lot of co-gens. Is that included in the model?

**T. Van Cutsem**: Yes. It can be included. It's a dynamic type of model. I don't see why it would be a difficulty



including this.

**D. Koval:** But you wouldn't know that from your load, like you do your EDF system.

**T. Van Cutsem:** Sorry. You mean the problem of not necessarily monitoring all the outputs in the real time operation?

**D. Koval:** In real time with this distributed generation, you get a problem.

**T. Van Cutsem:** That's right. We suppose we can monitor. You have to think about this problem.

**D. Koval:** Because we're having this problem, a lot of them are with the co-gens. They're on and then they're off.

**T. Van Cutsem:** I see what you mean. Maybe in the case of co-gens, the power control is easier. Maybe that will have a power factor logic that can be incorporated. But, in principle, I just made here this simple assumption I can monitor all power companies.

**D. Koval:** I got another question for Professor Tomsovic. When you said you define a contingency, all I saw on one of the slides is three-phase fault, what about single line to ground faults? And the other thing is what about, like fire alarms and area storm historical.

**K. Tomsovic:** If you look at the WSCC criteria, I didn't put in up there, there are four different levels of performance you can probably see. The single line to ground fault is, they are certain in terms of response that you expect. So we're looking at the problem we often don't have the models to do all the studies for all those contingencies. For the most part, we're doing three-phase faults. But I don't know if you're familiar with that. As far as, I guess, you'd call it correlated contingency or something like that, where you got a number of values coming together, that's not something we've looked at. I imagine there are operating processes for what they do and certain tough situations when I got a certain section under some sort of emergency or whatever. That's not something we looked at.

**D. Koval:** What we asked was that every time you get some bush fire, you wiped out a few transmission lines, and we're tied in here in the system, and we get wiped out. It happened a couple of times. Why don't they consider the fires that are taking up the lines?

**K. Tomsovic:** I don't know if they do or not. The department that I do the study with doesn't look at those types of emergencies where you got several correlated outages.

**C. Vournas (NTUA):** If I may add a small comment to

the question by Dr. Koval. I personally happen to know two types of distributed generators and co-generations. In the case of distributed generation, it was wind-generation from induction generators. In this case the power factor was controlled locally by the switched capacitors, so you can take it as a constant power factor, part of the constant power factor load. The other case was a refinery: when the co-gen is working, it's always working on power factor control. So again we can view this as constant power factor injection. I don't expect that in security assessment they will play a major role, unless there are other types of distributed generation I do not know of.

**J. P. Paul (EdF):** I think if the independent protection is small, it is not very important, no importance for voltage instability. If it is quite great, I think maybe the ISO will ask, in the contract of co-generation, some on line information. So regarding my question to Professor Tomsovic, I understood you are able to estimate margin depending on your model and operating, and your margins estimated for different criteria. I wonder when you present these different values of margins to the operator, how does he choose out of, or does he combine the different margins that are computed?

**K. Tomsovic:** At the current stage where we are, since we don't have all of these 30 criteria completed yet, we haven't got to the point to actually present something to the operator. But let me say what our idea was, presently they have this table essentially give them the limit on major transfer. So we're looking at past 15 in the California, the AC and DC inter-tie. Our idea would be to eventually put in another layer on, which is to try to adjust what that limit is, to let them know what that transfer limit is, which you could do by looking at the condition after you calculate all the margins and make sure they are within limits. Then you can start varying some of the inputs, which is flow on different key variables, and then you can calculate what your estimate of that margin on the transfer. Your estimate of what the transfer limit was across that. That was my idea at this point of what you present to the operator. Maybe you would want to give them more details in terms of, you know this is your limiting criteria, this is what you have to worry about. That might be useful as well for them.

**C. Canizares (University of Waterloo):** My question is for Mr. Kulic. I was quite interested in your simulations and bifurcation study. I was reading your paper and, in some part, you said that you associated that to voltage as opposed to angles by looking at participation factors. I look at similar phenomena since, unless you have a dynamic load modeling or some sort, how did you come up with this participation factors, how did you conclude it that it was voltage from these factors? These are not directly available. They don't have a dynamic load. Hopefully you can answer this question, and it's not a project for Professor Popovic.

**F. Kulic:** The simulation is done completely by a software package developed by professor Popovic so my part was about neural network clustering system reduction. There was a voltage magnitude in the center inertia system, and the result of the simulation. So there is a changing of the voltage magnitude, so I don't know anything about the angles.

**C. Canizares:** If you can relate the question to Professor Popovic. It will be greatly appreciated.

**F. Kulic:** Yes, of course.

**Chairman:** Yes. I think Claudio you're right, send a written contribution, and then we give the opportunity to Professor Popovic to make a reply. The same for Professor Iwamoto.

**F. Wu (Hong Kong University):** My question is to Mr. Kitagawa. Do you think your study of distributed parallel processing is scalable in the sense that your experiment uses 2 PCs and you show the result, the speed improvement is almost 2 by 1.86, when you have  $N$  machines, do you expect the speed-up would be  $N$ ? Or do you expect any communication factors that will make the factor less than  $N$ ?

**S. Kitagawa:** It is difficult to scale the development.

**Y. Fukuyama:** I'm the co-author of this paper. Actually we have a lot of PCs in the network inside companies. Maybe usually we can just use a few PCs, maybe 2 or 3, so we are not considering the performance with more PCs so we are not sure.

**M. Begovic (Georgia Tech):** I have a question for T. Van Cutsem. Your conclusions are along the line of what has been known for what power margins are much less non-linear in an estimation of system stability margin than anything else that has been proposed. I'm curious regarding that and the number of simulations that you have done. Could you establish any correlation between non-linearity in the margin that you have observed in any events, and the hope to redefine margins to remove those circumstances? Also how do you estimate the execution time of the algorithm you classify as on-line or off-line tool? In case of the former, would you argue that the choice of short term load forecasting would be the best direction for estimating the stress?

**T. Van Cutsem:** Thanks for your question. In many cases I observed that linearity was not that bad. If you approximate by sensitivity, most of the time analytical, and make a comparison, you will find quite a good argument for reasonable changing parameter. I think other people also confirm this. Finally, even in the CIGRE report that was issued in the beginning of the 90's, we had a comparison of indices, and it was found

that even by just measuring the MVAR margin, while the system was stressed by the MVAR, we had a quite good linear prediction capability. This was found in the CIGRE system. Here we have a lot of computation on the two different systems, in all 32 systems. The reactive power disturbance tends to propagate somewhat farther than what you would expect in the real EDF system, which is the biggest of the European systems, in which reactive limits are very low. That's my experience, I think there are many cases where you observe that things are not that nonlinear of in terms of relationship of power margin to power parameter. About the execution time, you can find some good information in the reference quoted at the end of the paper. Of course you have this binary search, which takes several simulations to reach the value of the  $S^*$  stress, and these are fast simulations. You don't have to do this for all the contingencies. Contingency ranking is very important. The way to rank contingency is by pushing the system at what I called, in my presentation, the maximum stress. There you can simulate all the contingency methods. That could be a load flow, an AC load flow, or even load flow, it depends. Then you can sort all your contingencies and keep those that are potentially harmful, and leave those ones, because there is no point in computing the reactive reserve for very harmless contingency. You can concentrate on the few more important ones. I should ask that as you compute, as long as you perform this binary search to compute something like ATC or load power margin in your system, it doesn't cost anything to just pick up the value of the generator. It is something you call bookkeeping. I mean you just record the value, and retrieve them later on, and make easy calculations. Your last point was about the use of load forecasting as a suggestion of track direction, am I right? Yes. This question relates to the appropriate stress on the system. It appears from the EDF system that you can see the local effect of the contingency. The best choice is to make a national load increase, which means increase in a national level, involving the whole system. In this case, any load forecasting will be very helpful, it would certainly indicates the direction which you should stress your system.

**E. El-Araby (Hiroshima University):** I want to ask Professor Van Cutsem. You said it is very difficult to really assess a reserve for a lot of systems. A lot of methods have been used many times. It was assessed to sub-areas. According to the local generation would reach the maximum limit first, and some reactive power would be imported to this area, and the reactive losses of the weak boundary is used as an index. Is it possible to use something like that? Will it work or not?

**T. Van Cutsem:** I think you're raising a philosophical question of methodology in term of approaching the problem from the area viewpoint, or from the viewpoint that we have adopted here. I think the main point is

that you need this area identification, so how would you perform this on the base configuration, on the sensitive type of information? So there is a big risk that your contingency changes the picture quite a lot in your system. In our case, in some sense, we don't define anything in advance, we just feel the effect of the contingency, define the appropriate set by just observing in the course of this surge after stressing the system by just observing the natural reaction of generators. So it is a very simple method. It is pragmatic in a sense that it can adjust to any system more developed than a configuration. You don't need to update the area and have the maintenance of this information on your model. These are the pros and cons. I'm aware of the work done by other colleagues, and probably there are advantages in this approach so o in terms of understanding the mechanism of stability, I have some reservation about the effect of large disturbances. In this application, we don't confine ourselves to small voltage deviations, that we would like to push the system up to the limit. So it can create quite a lot of distortions in the system in terms of who is belonging to what area.

**C. Canizares:** I guess I disagree on one of the statements that Miroslav just made, which is regarding the linear active, reactive power. I didn't quite understand where active power is linear, or reactive power doesn't seem to be linear. Maybe I misunderstood. Another statement was that when Dr. Van Cutsem said that, when you have these variations of parameters with respect to the margins, right? Certain margin for certain parameter, the margin seems to be pretty linear. You change the parameter, the change seems to be very linear. However, up to a point, I've noticed that in certain systems when you start seeing the limits and things like that, things can become significantly non-linear. So I guess we have to be a bit careful how we state this.

**T. Van Cutsem:** I'll agree with you at some point. Look at the figures in the paper. It's full of generators and limits, I mean especially in the EDF system. I'm just observing linear index, I can not state this is a universal tool. But I observe this linear variation and as Miroslav quoted, all the researchers observe this as well. It would be nice to have a counter example.

**S. Corsi (CESI):** Just to better understand the point already discussed on linearity, the linearity of the several comparisons with the system stress. I warn that the system stress changes with the active power. I wonder if it also does in reactive power.

**T. Van Cutsem:** Both active and reactive powers. Yes, sure the load. We just assume constant power factors for the load. I should start at this point. Part of the linearity in this case comes from the thing from the pre-contingency situation. That's the essence of observing reserve. We have to observe them in the pre-contingency

configuration, and anticipate the contingency. But by itself, when you change the stress, what is changing is the reactive output of generator in the current configuration of the system. You just anticipate through the value of the minimum reserve the effect of the contingency. But as the system is stressed, your system is in pre-contingency configuration, which is most of the time more linear situation, as compared to post-contingency one. It's quite common to operate a power system without the reactive limit in the pre-contingency configuration. That's common practice.

**N. Yorino (Hiroshima University):** I experience that for the reactive power induced bifurcation, which Professor Canizares pointed out yesterday, we have carried out several simulations. We found that in the simulation, for some contingency, the pattern of bifurcation is different. By the pattern I mean in some contingency, the critical generator is, for example, this. But for other contingencies, the critical generator is different. The pattern of the limit is quite different. In that case, I guess it is quite difficult to identify it by such a measure.

**T. Van Cutsem:** If you look at the example in the paper, you have one local contingency, and one regional one.

**N. Yorino:** Regional? For example, for some contingency, the pattern of the Q limits, the set of the generator which hit Q limits, is different.

**T. Van Cutsem:** Yes. The examples given in the paper involve two contingencies. One is with local effect where you have limited numbers of generators reaching the limit, and the other one with regional effect where there are many generators. If you didn't throw away your Santorini proceedings, you can check the paper I have there with the EDF colleagues. We have shown different modes of instability involving different generators and limit on the same system that it was used in this case. I agree with you that the pattern can be quite different. But I think you incorporate it easily.

## Answer to the second question of Professor Shinichi Iwamoto (Waseda University, Japan)

Professor Dragan S. Popovic and Filip J. Kulic

During the simulation for learning of the artificial neural networks the positions of the tap changers and SVC parameters were moderate vary, which simulates real effects of AVRs. In that way the topology of network were changed. More precisely, during simulations were simulated adjustment of AVR of tap changer and SVC

according to the network state changes. In that way for the certain network configuration and certain load level in the system were taken appropriate positions for tap changers and appropriate productions of reactive power for the SVCs.

## Answer to Professor Canizares comment (question)

Professor Dragan S. Popovic and Filip J. Kulic

Yes, this is the case of angle instability, but in the same time also is present and voltage instability. Moreover, modal analysis of the critical operating point shows in this case that the unstable mode is dominantly caused by the system variables associated to AVRs. Figure 1 shows participation of the state variables in critical mode depending on load level. This figure shows the participation of state variables in critical mode, for every considered load level. For every load level and for every mode, on figure are shown three state variables with the greatest influence. From the picture it can be seen that for critical operating point (load level 1.73 p.u.) dominant influence to unstable mode is performed

by variables associated to voltage phenomenon, which participate in critical mode with the total of 78% of the influence (Eq4' participate with the 46%, Rf4 with the 20% and Eq7' with the 12% of the influence). All other state variables participate with the total of 22% of influence, where the influence of d4 is 10% and w4 is 9%, and influence of all other state variables is 3%. Practically, as the most of authors concluded angle and voltage instability must be integral considered, that is word about one system instability [1,2]. In that way, considered instability can be conditionally named "voltage instability". However, this results shows that the problem of instability must be integral examined.

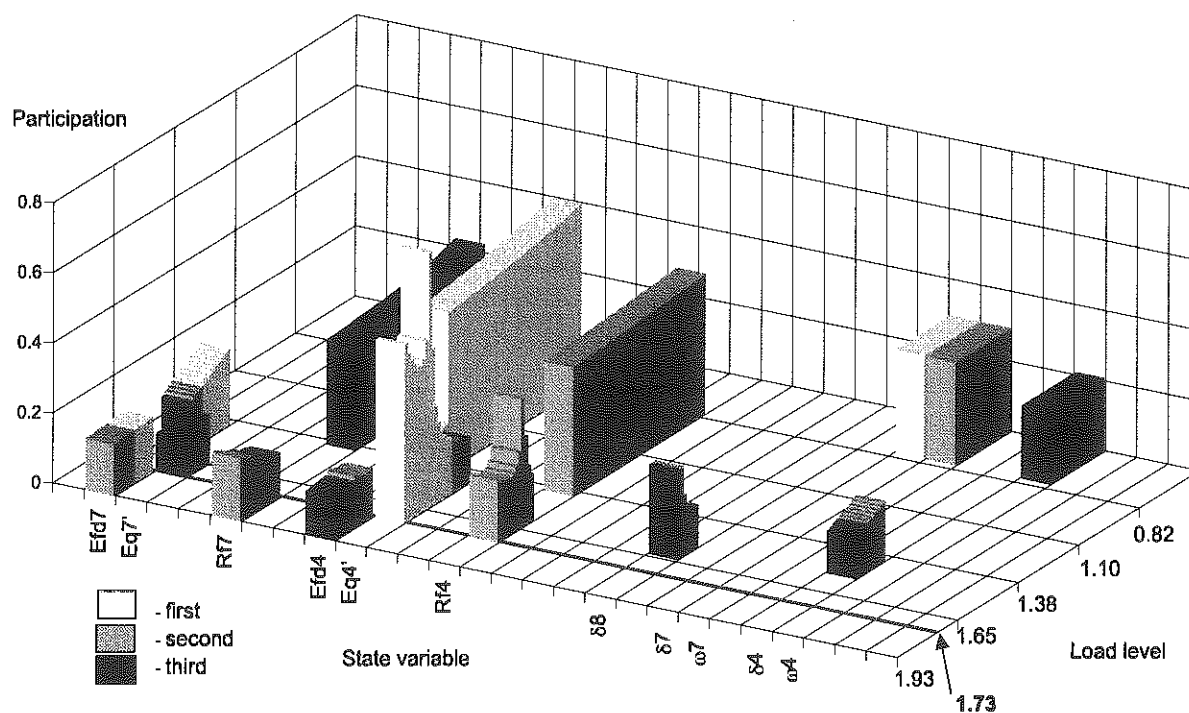


Figure 1

## An Improved Methodology for Security Assessment of Power Systems in Conditions of a Deregulated Environment

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**Abstract** - This paper presents the relevant aspects of an improved methodology for steady-state security assessment of electric power interconnection, in conditions of deregulation of electric power market. Its characteristics enable the unification of corresponding computer program, autonomy and uniformity of security analysis, as well as their fast and successive realization, which have a great practical importance.

The main characteristics and possibilities of proposed methodology, especially in context of transfer capability evaluation, are demonstrated on the example of the existing electric power interconnection in the Balkan area.

**Keywords:** Improved methodology, Security assessment, Deregulated environment, Balkan interconnection.

### Introduction

An important problem in modern Electric Power Systems (EPS's) is the provision of the necessary level of operational security [1]. In cases of single or multiple disturbances the power system is required to remain inside previously defined tolerance limits.

In recent years, the increased practical interest to this problem and corresponding new challenges are essentially due to increased loading of EPS's, combined with a process of deregulation in electric power market and restructuring of the power utilities. Also, open access power systems need accurate transmission capacity determination to guarantee secure operation for all transactions. In other words, electric power markets need to know how much power can be transferred between certain points, e.g. to know the real technical limitations of these power exchanges due to the set of various network constraints.

As the practical importance of obtaining the necessary level of electric power system security is well-known fact, especially in conditions of deregulated environment, the authors will proceed immediately to presenting the main objective of the paper.

This paper deals with the relevant methodological and practical aspects of an improved methodology for steady-state security assessment of power systems, in conditions of deregulation, e.g. open electricity market. In modern Energy Management System (EMS) [2-5], the most popular approach to the steady-state security assessment is based on well-known fast decoupled load-flow method [6], with single iteration fast contingency selection. Also, this method is used for initial load-flows solution.

The improved methodology for steady-state security assessment, proposed in this paper, consists of the following relevant parts (which differ to the usually approach):

- Two procedures for initialization of steady-state security analyses of power systems e.g. the procedure for solving the initial load-flows problem, which preceding these analyses. The first procedure enables the load-flow solution for given initial generators scheduling in interconnection considered. The second procedure gives the load-flow solution in conditions of realization of a set bilateral or multilateral exchange programs between EPS's in interconnection considered. These procedures are fully consistent with the specially developed method for the following steady-state security analyses [7]. Such a characteristic of these procedures enable the unification of corresponding computer program, autonomy and uniformity of steady-state security analysis, as well as their successive realization, which have great practical importance;
- procedure for forming the unified external network equivalents, with adaptive buffer system selection, consistently respecting the effects of primary voltage and frequency control of neighboring power systems [8];
- procedure for fast and efficient contingency selection [9], which is based on results from the single iteration of specially developed fast decoupled load-flow solution method, in which the power system frequency is relevant variable;
- simple method for the fast and sufficiently accurate assessment of dynamic variation of power system frequency [10], during the time of its primary control, as well as the quasi-stationary value of its frequency.

For the injection losses type of disturbance (e.g. outage of large generators), with this known value of frequency, the more accurate results after first iteration are obtained;

- forming the practical and realistic security indices for selection of potentially critical disturbances [8], according to the real power performances, as well as according to the control and protection devices characteristics;
- for potentially critical contingency, the continuation of iterative procedure for solving the load-flow problem is performed, based on specially developed fast decoupled method [7,8].

This specially developed method enables successive solution of the load-flow problem for a set of characteristic post-dynamic quasistationary states of the power systems: states resulting from primary voltage and frequency control, states after the action of automatic secondary control of frequency and tie-line power and states after corresponding possible dispatch activities, if necessary (corrective control). For these purposes, the load-flow models have been consequently improved. These improved models are solved by fast decoupled procedures, which have been developed by considering the “physical” nature of the phenomena under study.

Such a characteristics of this improved methodology are enabling, among other, very efficiently and accurately transfer capacities evaluation of real interconnection, due the latest definition [11]. In other words, this methodology is enable to identify the kind of transfer capacities, e.g. to determine, with very good accuracy, the Total, Net and Available Transfer Capacities, according to the facts, that the methodology proposed strictly calculates the transmission effects of primary frequency and load-frequency controls. In this conditions, the significant part of Transmission Reliability Margin is included (except the remain part, while take account the uncertainties of system condition and the precision data and calculation methods.)

Also, the results of application of proposed methodology give the initial base for evaluation the effects of some relevant ancillary services [12] (above mentioned primary and secondary control).

The first practical experiences in the application of the improved methodology have been gained on an example of the synchronous parallel operation of the EPS's of Yugoslavia, Romania, Bulgaria, Former Yugoslav Republic of Macedonia, Greece and Albania. In other words, the present state of the interconnection in the Balkans (the second UCTE synchronous zone), which is operating as an “island” with respect to the UCTE interconnection, has been analyzed.

The same example was used to compare the methodology developed with a more complex approach, which is

monitoring the transient processes in greater detail by simulating the dynamic response of power systems, after relevant disturbances. The results obtained for the so called “base case” (“zero” exchange program between EPS's), as well as for a set of multilateral and bilateral exchange programs, at first, show a very good, fast, and reliable convergence characteristics of procedure developed and also show their great flexibility in cases of creation of important exchange programs between EPS's considered.

### Nomenclature

$N$  - total number (set) of all nodes of the interconnected power system

$NG$  - total number (set) of generator nodes ( $NG \in N$ )

$NSV$  - number (set) of generators with static voltage-reactive power characteristic ( $NSV \in NG$ )

$NL$  - number (set) of load nodes ( $NL \in N$ ;  $NL = N - NG$ )

$M$  - number (set) of power systems in synchronous parallel operation

$NAGC_j$  - number (set) of generators which participate in the secondary frequency control and tie-line power (or automatic generator control) in  $j$ -th power system, i.e. area ( $NAGC_j \in NG$ ;  $j \in M$ )

$NAGC$  - number (set) of all regulation power plants in interconnected power system

$$(NAGC = \sum_{j=1}^M NAGC_j)$$

$P_{G0i}$  - active power of the  $i$ -th generator in the initial steady-state

$k_{pi}$  - primary frequency control constant of  $i$ -th generator

$\Delta f = f - f_0$  - deviation of the quasi-stationary value of frequency  $f$  from its initial value  $f_0$

$k_{si}^j$  - the participation factor of the  $i$ -th regulation generator in the AGC control of  $j$ -th interconnected area

$Q_{G0i}, V_{0i}$  - reactive power and voltage at the ends of  $i$ -th generator in the initial steady-state

$sv_i$  - droop of the static voltage-reactive power characteristic of the  $i$ -th generator

$P_i, Q_i$  - injected active and reactive power

$P_L(V_i, f), Q_L(V_i, f)$  - load active and reactive power at node  $i$ , as a complex function of the voltage at its end and the quasi-stationary value of the frequency

$\Delta ACE_j$  - static area control error of the  $j$ -th interconnected area ( $j \in M$ )

$P_{Tj}, P_{T0j}$  - actual and scheduled total tie-line power of  $j$ -th interconnected area

$B_j$  - the bias factor on the automatic generator control (or secondary control constant) of  $j$ -th area

$REG_j$  - amount of regulation power of  $j$ -th area necessary for elimination the own static control error  $\Delta ACE_j$

$V_i, \theta_i$  - magnitude and phase of voltage at node  $i$

$B_{ij}$  - susceptance of the element  $i$ - $j$

$k, l$  - iteration indices

### Load-flow models in characteristic post-dynamic quasi-stationary states

For the state resulting from primary voltage and frequency control, the following balance equations hold [7,8]:

$$\Delta P_i = P_{GOi} - k_{pi}\Delta f - P_i = 0, \quad i \in NG \quad (1)$$

$$\Delta Q_i = Q_{GOi} + Q_{Oi} \frac{V_{GOi} - V_{Gi}}{s_{Vi} V_{GOi}} - Q_i = 0, \quad i \in NSV \quad (2)$$

$$\Delta P_i = P_{Li}(V_i, f) - P_i = 0, \quad i \in NL \quad (3)$$

$$\Delta Q_i = Q_{Li}(V_i, f) - Q_i = 0, \quad i \in NL \quad (4)$$

which satisfy the following constraints:

$$P_{G \min i} \leq P_{Gi} \leq P_{G \max i}, \quad i \in NG \quad (5)$$

$$Q_{G \min i} \leq Q_{Gi} \leq Q_{G \max i}, \quad i \in NG \quad (6)$$

It should be noted that in this case, as opposed to the usual approaches, the upper and lower limits of active and reactive power generation are not constant, *a priori* defined quantities, but rather corresponding functions of relevant state variables [13].

In the case of the post-dynamic quasi-stationary state, occurring due to automatic secondary control of frequency and tie-line power, the balance equations of the form (1) still hold, but only for generators those are not participating in the secondary control, as well as (2)-(4). Here two new equations are added (limits (5) and (6) still hold):

$$\Delta P_i = P_{GOi} - k_{pi}\Delta f + k_{si}^{REG} \Delta f - P_i = 0 \quad i \in NAGC_j, j \in M \quad (7)$$

$$\Delta ACE_j = P_{Tj} - P_{T0j} + B_j \Delta f = 0 \quad j \in M \quad (8)$$

The effect of the automatic secondary frequency and tie-line power control, together with (7), results in (8), which gives the static area control error of all the EPS's in the interconnection, i.e. of all the control areas.

Equations (1)-(6) are also valid in the case when the necessary dispatch measures are performed (e.g. increasing power output from plants where possible, introducing fast start units, load reduction, etc.) with the aim of further reducing the consequences of the disturbance. In this case, the initial state is the one obtained at the end of the secondary control stage, which secures a continuity of the load-flow calculations.

### Procedure for solving the nonconventional load-flow models

The first step in the development of the solution method is the application of the Newton-Raphson method [14], on the balance equation (1)-(4). Then, inspired by [6], in the formation of the Jacobian matrix, the similarly justified assumptions and simplifications resulting from the "physical" nature of the problem are introduced. Thus, we

obtained the following two decoupled systems of equations (naturally, only during one iteration), which are solved successively, in accordance with the iteration indices  $k$  and  $l$  [7,8]

$$\begin{bmatrix} \Delta \mathbf{P}/\mathbf{V} \\ \Delta \mathbf{P}_r/\mathbf{V}_r \end{bmatrix}^k = [\mathbf{H}' \quad \mathbf{F}'] \begin{bmatrix} \Delta \boldsymbol{\theta} \\ \Delta(\Delta f) \end{bmatrix}^{k+1} \quad (9)$$

$$\Delta \mathbf{Q}/\mathbf{V}^l = \mathbf{L}' \Delta \mathbf{V}^{l+1} \quad (10)$$

The elements of the coefficient submatrices  $\mathbf{H}'$ ,  $\mathbf{F}'$  and  $\mathbf{L}'$  have the following constant values for a given network topology:

$$\begin{aligned} H'_{ii} &= V_n B_{ii}, \quad i \in (N/r) \\ H'_{ij} &= V_n B_{ij}, \quad i \in N; j \in (N/r) \\ F'_i &= \begin{cases} k_{pi}/V_n, & i \in NG \\ 0, & i \in NL \end{cases} \\ L'_{ii} &= \begin{cases} Q_{GOi}/(s_{Vi} V_{GOi}^2) + B_{ii}, & i \in NSV \\ B_{ii}, & i \in NL \end{cases} \\ L'_{ij} &= B_{ij}, \quad i, j \in (NSV \cup NL) \end{aligned} \quad (11)$$

where  $V_n$  represents the rated voltage. The scalar  $\Delta P_r/V_r$  represents the power mismatch (divided by the magnitude of the voltage) of an arbitrary reference node, which has an *a priori* defined phase angle (usually set at zero).

The system of equation (9) and (10) remains valid for the state of the system after the action of the automatic secondary frequency and tie-line power control [7,8]. In this case, the vector of active power mismatch contains the coordinates which pertain the regulating power stations, according to relation (7), while the necessary magnitude of mismatch, that is, the static area controls error, is determined separately, during the successive iterative solution of the systems (9) and (10), using (8). It should be pointed out that the tolerance for the condition  $\Delta ACE_j = 0$  ( $j \in M$ ) is in direct correlation with the actual capabilities (imperfections) of the existing systems for the automatic secondary frequency and tie-line power control.

### Procedures for solving the initial load-flows

In this section of paper the determinations of procedures for solving the initial load-flows will be made, which are based on nonconventional load-flow models (equations (1), (2), (3), (4), (7) and (8)), and their solution techniques (decoupled equations (9) and (10)).

#### Load-flows for given initial generators scheduling

In these conditions, all active generator powers are known (except for chosen reference generator, i.e. conventional slack node). Then, in balance equations (1), the part  $k_{pi}\Delta f$  doesn't participate, except for reference generator. Next,

according to the facts that all generator voltages are known, the all balance equations of form (2) also, don't participate.

Thus, for this type of initial steady-state, the balance equations of the form (1) still hold (but without the part  $k_p \Delta f$  for all generators, except for reference), as well as the balance equations (3) and (4), (with given constant values of load active and reactive powers), which satisfy the constraint (5) and (6).

Therefore, the way of forming the actual balance equations, leads to the manner of its solution technique, e.g. to the manner of modification and application of the given decoupled equations (9) and (10).

So, the system of equations (9) is still of the order N (in submatrix  $F'$  exists only primary frequency control constant of reference generator) and the system of equations (10) is reduced to the order NL.

In this manner, by iteratively solving the modified decoupled equations (9) and (10), (in manner before described), with respecting the constraints (5) and (6), one can find the following unknown variable:

- ⊙ - N-1 dimensioned vector of phase angles of all nodes of the EPS in interconnection, except angle of reference (or slack) node, which has a fixed value (usually set at zero),
- $\Delta f$  - deviation of "quasistationary value of frequency" in relation to the initial value (artificial variable),
- $V$  - NL dimensioned vector of voltage magnitudes off all load nodes in interconnection considered.

It should be noted that, in these conditions of initial state, the value  $\Delta f$  is not real frequency deviation, as opposed to the conditions of post-dynamic quasistationary states.

#### *Load-flows for a set of bilateral or multilateral exchange programs*

In paper [15], the formulation and practically application of the methodology, which performs more accurate evaluation of the basic technical effects resulting from significant power transits, are been presented. This methodology takes into consideration the existing operational practice in real interconnection (such as the action and effects of automatic primary voltage and frequency control, as well as the next action and effects of the secondary frequency and tie-line power control). In other words, its is completely based on nonconventional load-flow models (equation (1)-(8)) and their solution techniques (decoupled equation (9) and (10), with respect of equations (7) and (8)).

After load-flows solution in initial (base) steady-state by procedure described before (by minor modifications of decoupled equations (9) and (10)), the scenario of exchange programs considered is formed. For this purpose, the

corresponding corrections of injection of selected generators are made (by increase injection in the exporting EPS and by decrease the injection in the importing EPS). Next, the load-flows solution is made, by applying the equations (9) and (10), with respect of equations (7) and (8).

#### **Global concept of improved steady-state security analyses**

Figure 1 presents the global concept of the proposed improved methodology (computer program STATIC) using flow diagrams of the basic functions in security assessment. In block 1, a set of states of interconnection considered is formed. This methodology uses a unified data base, as a segment of the complex data base necessary for the operational planning of EPS.

Next, in block 2, load-flow solutions for given generators scheduling are performed, and in block 3, load-flow solutions for a specific bilateral or multilateral exchange program are performed.

The creation of the unified external network equivalent, consistently respecting the effects of primary voltage and frequency control of neighboring power systems, are performed in block 4 according to the procedure, given in [8]. This type of equivalent, applied to the networks of lower voltage level (e.g. 110kV or 150kV) can be very useful in context of transfer capability evaluation, taking into account real operational conditions of interconnection considered.

In block 5, disturbance list creation is made. The computer program STATIC provides to the operator the way to define the list of characteristic disturbances, as well as the automatic performance of these functions (outages of all generators and all elements, which are loaded above the previously specified values).

The next blocks 6,7 and 8 perform the fast contingency selection, which is based on results from the single iteration of solving (9) and (10).

In modern EMS, the most popular approach to the fast contingency selection is based on results of single iteration of fast decoupled power flow [7], which is proposed in [16] (single iteration contingency selection or 1P-1Q method). In methodology proposed, the selection is based on single iteration of (9) and (10), in which the power system frequency is the relevant variable (1Pf-1Q method).

For the injection loss type of disturbance, applying a simple method [10], fast and sufficient accurate assessment of dynamic change of frequency during the time of its primary control, as well as the quasistationary value of this frequency, are determined. The development of a low-order system frequency response model is based on the main



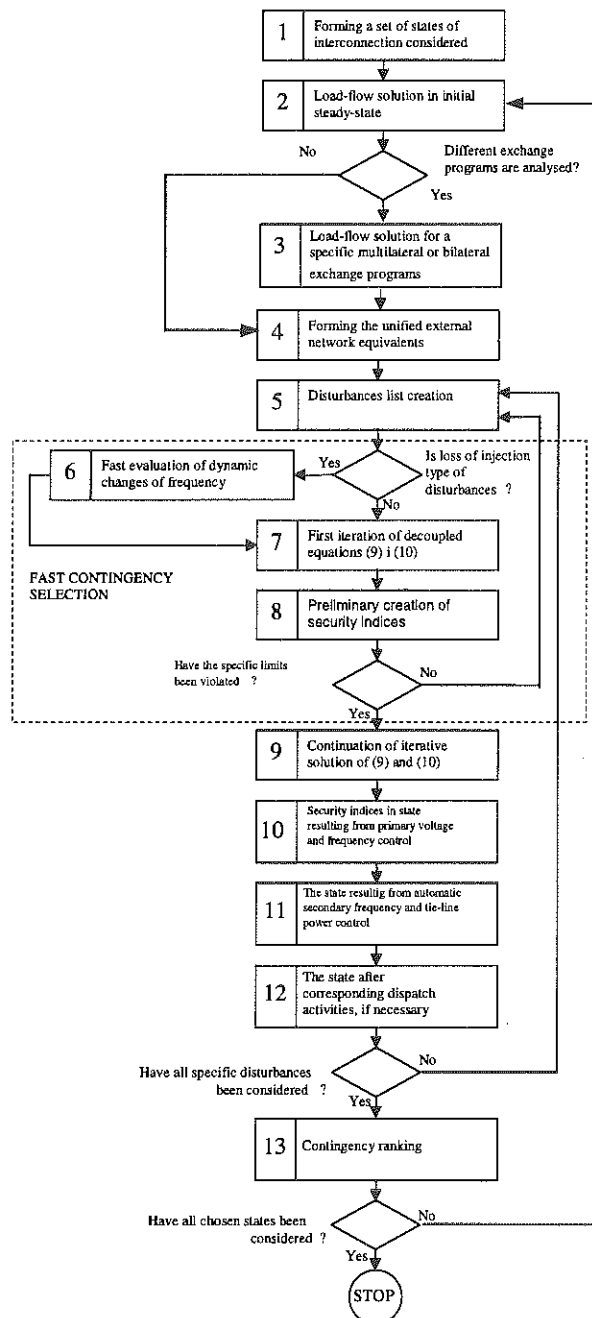


Figure 1: Global flow diagram of improved security analyses of power systems

assumption of uniform movement of generators, which enables representation of the power system through an equivalent controlled synchronous machine. The analytical expression, formed for non-zero initial conditions, permits the tracking of possible structural changes in the EPS during the process being studied. This, in turn, allows the monitoring, *inter alia*, of the effects of automatic underfrequency load shedding and underfrequency

protection of generators. Also, with the known quasistationary value of frequency, the more accurate results of single iteration of (9) and (10) are obtained.

The continuation of iterative procedure (full contingency analysis) is made for this case:

- violation of voltage magnitude limits;
- violation of element current limits
- violation of generator reactive limits;
- shortcoming of spinning reserve, according to the disturbance;
- shortcoming of regulation reserve, according to the disturbance;
- indication of action of underfrequency load shedding or underfrequency protection of generator;

For the potentially critical contingency, the continuation of iterative solution of (9) and (10) is performed; e.g. the successive solutions of load-flow for an above mentioned characteristic post-dynamic quasi-stationary state are made (blocks 9,10,11 and 12). Finally, in block 13, contingency ranking is made, according to the values of specially formed deterministic performance indices.

Therefore, as a fundamental characteristic of the proposed methodology, it should be point out the unified manner of initial load-flows solutions, fast contingency selection and solutions of all the necessary load-flows, by the presented simple unique fast decoupled procedure, with constant elements in the corresponding coefficient matrices, as well as with a minimum number of modifications and additions depending on the character of the initial and the post-dynamic state of power system under consideration.

Such a characteristics of the methodology proposed are enable the unification of corresponding computer program (STATIC), autonomy and uniformity of security analysis, as well as their successive realization, which have a great practical importance.

#### Practical application of improved methodology

The first practical experiences in the application of this improved methodology have been gained on an example of the synchronous parallel operation of the EPSs of Yugoslavia (YU), Romania (RO), Bulgaria (BG), Former Yugoslav Republic of Macedonia (FYROM), Greece (GR) and Albania (AL), on the basis of data given in [17]. In other words, the present state of the interconnection in the Balkans (the second UCTE synchronous zone), which is operating as an "island" with respect to the UCTE interconnection, has been analyzed.

The results of initial load-flows calculations [18] show a very good convergence characteristics (fast and reliable) in case of given generators scheduling, as well as in case of a set bilateral or multilateral exchange programs between EPSs in interconnection considered.

Also, the results for a series of characteristic single and multiple contingencies are confirmed very good and reliable convergence characteristics of developed fast decoupled procedures, even in cases of most severe disturbances and great flexibility to the large variation in load characteristics (in case of complete interconnection as well as in case of forming the unified external network equivalent).

Table I gives a good illustration of basic characteristics of fast contingency selection method (1Pf-1Q). It gives the four quasi-stationary values of frequency ( $f_1$ - $f_4$ ), for following outages: a) one unit in TPP N. Tesla B (YU) (injection loss of 600 MW); b) one unit in NPP Kozlodui (BG) (871 MW); c) two units in NPP Kozlodui (BG) (1742 MW) and d) simultaneous (hypothetical) outages of units in case a) and b). The value of frequency  $f_1$  is obtained after single iteration of equation (9), where the initial value was equal to the nominal value. The value  $f_2$  is also obtained after single iteration, but the initial value of frequency was estimated according to [10]. The full solution of (9) and (10) gives the value  $f_3$ . Finally, the value  $f_4$  is obtained by a more complex approach [19], which monitors the process of primary frequency control of duration up to 25 s in greater detail. The Fig. 2 shows the dynamic variation of frequency, obtained by mentioned approach.

Table I - The quasistationary values of frequency in state resulting from primary frequency control

| Outage | The quasi-stationary values of frequency [Hz] |        |        |        |
|--------|-----------------------------------------------|--------|--------|--------|
|        | $f_1$                                         | $f_2$  | $f_3$  | $f_4$  |
| a)     | 49.926                                        | 49.928 | 49.929 | 49.930 |
| b)     | 49.892                                        | 49.895 | 49.892 | 49.896 |
| c)     | 49.776                                        | 49.772 | 49.781 | 49.784 |
| d)     | 49.813                                        | 49.815 | 49.813 | 49.817 |

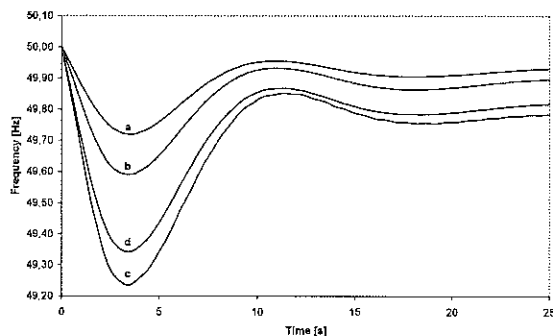


Figure 2: Dynamics of frequency variation, for outages a)-d)

The results presented in [8,9], as first, show very good characteristics of unified external network equivalents. Consequently to them, the problem of buffer zone selection is relaxed, e.g. the practical experiences show that keeping only the boundary nodes is sufficient, considering outages of generators in internal system. Next, the results show that the single iteration gives very satisfactory indication for contingency selection, especially in the case when the quasi-

stationary value of frequency is estimated. Furthermore, good convergence characteristics of developed fast decoupled procedures have been confirmed, even in case of most severe disturbances. Also, the results show a good correspondence between the dynamic approach [18] and the methodology proposed.

Generally speaking, in context of accuracy of fast contingency method, it should be noted that all the cases, which are insecure after full solution, have been also insecure after the first iteration of (9) and (10).

In conditions of deregulated environment, the main practical application of proposed methodology is in context of stricter transfer capacities evaluation.

From many results that were obtained, the case of power exchanges (hypothetical) between Romania (export) and Greece (import) is chosen as a good illustration [20], according to the maximum transmission path length in interconnection considered. For this scenario, the injections of NPP Cerna Voda (RO) (increase) and injections of TPP Ag. Dimitros (GR) (decrease) are changed in steps of 50 MW. The starting point (e.g. the base case) corresponding to the pick (winter) load condition, without any exchange programs between the EPS's. According to the definition of transfer capacities, given in [11], in this conditions, the Notified Transmission Flow (NTF) does not exists.

Figure 3 shows the block diagram of examined interconnection with the active and reactive power flows (MW/Mvar) on interconnecting lines in two cases: without any exchange programs between the EPS's ("zero" exchange program) and when Romania exports 600 MW to Greece (values given in parentheses).

The second case (RO→GR, 600 MW), corresponds to the stop of procedure of transfer capacity evaluation, e.g. when the predefined security rules are violated. This procedure strictly respects the N-1 security criterion (lines 400 and 220 kV, transformers 400/231 kV and generators) and N-2, in case of double circuit.

Table II shows the violation of current limit (in %), which are registered for this transfer. In the some time, this transfer (RO→GR, 600 MW) is practically maximum steady-state possible in state of interconnection considered, respecting the facts that the registered overloads of transformers is tolerant (many EPS's in Europe, in winter conditions, permit 10-20% overloading of transformers). However, the question is which kind of transient capacities is obtained according to the following definition, given in [11]

$$NTC = TTC - TRM; ATC = NTC - NTF$$

where NTC represents the Net Transfer Capacity, ATC, Available Transfer Capacity, TTC, Total Transfer Capacity,

TRM, Transmission Reliability Margin and NTF, Notified Transmission Flow.

In practical example  $NTF=0$  or  $ATC=NTC$  considered. Next, the methodology proposed strictly calculates the transmission effects of primary frequency and load-frequency controls, e.g. the significant part of TRM is included (except the remain part, which take account the uncertainties on system conditions and the precision data and calculation models).

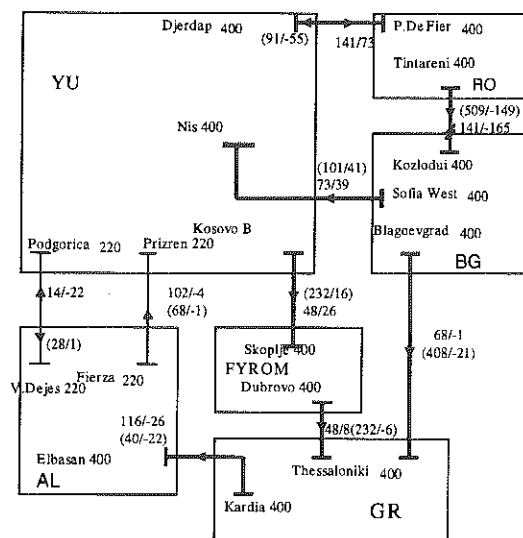


Figure 3: Active and reactive powers on interconnecting lines of Balkan interconnection

Table II - Violation of security limits in case: RO→GR, 600MW

| Outage of element                              | Violated element                       | Violation of current limit [%] |
|------------------------------------------------|----------------------------------------|--------------------------------|
| Line 400 kV Kosovo B (YU)-Nis (YU)             | Transformer 400/231 kV Nis (YU)        | 11.0                           |
| Line 400 kV Blagoevgrad (BG)-Thessaloniki (GR) | Transformer 400/231 kV Nis 2 (YU)      | 4.4                            |
| Line 400 kV Blagoevgrad (BG)-Radomir (BG)      | Transformer 400/231 kV Nis 2 (YU)      | 8.6                            |
| One unit 700 MW in TPP Cerna Voda (RO)         | Transformer 400/231 kV P. De Fier (RO) | 5.3                            |

Thus, the obtained value of possibly power transfer (600 MW) between Romania (export) and Greece (import) is near to TTC, or precisely, to TTC, reduced to the above mentioned remain part of TRM.

## Conclusions

A possible way to form an efficient unified methodology for stricter steady-state security assessment of EPS has been presented. Its principal characteristics are: (1) two efficient procedures for solving the initial load-flows problem, which are fully consistent with the specially developed fast decoupled method intended for the following steady-state

security analysis; (2) successive solution of the load-flow problem for a set of characteristic post-dynamic quasistationary states; (3) procedure for forming the unified external network equivalents, consistently respecting the effects of primary voltage and frequency control; (4) procedure for fast and efficient contingency selection; (5) practical and realistic security indices for selection of potentially critical disturbances.

Such characteristics of this improved methodology enable the unification of corresponding computer program, autonomy and uniformity of steady-state security analysis, as well as their successive realization, which have great practical importance. Also, these characteristics are enabling among other, very efficiently and accurately transfer capability evaluation of real interconnection, which were demonstrated on example of existing electric power interconnection in Balkans.

Thus, the methodology presented can be regarded as a useful addition to the software support of operational planning as an integral part of EMS of the Serbian Electric Power Corporation.

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## Secure Economic Dispatch: an "Economically Correct" approach in a deregulated market scenario taking into account the presence of FACTS devices

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### Abstract

With the electric market deregulation, it can be observed that the number of market participants is increasing more and more, while the transmission network remains practically the same. The transmission grid so becomes the most critical segment of the unbundled electric system, since it could be operated in conditions closer to the security limits. More than before, in the new deregulated scenario, security is so becoming a relevant requirement. To meet this requirement, the Independent System Operator (ISO) has to choose the proper actions to solve security problems due to unfeasible contracted transactions between market participants, in pre and post contingency state, according to economic criteria. To determine such actions, in this paper a model previously proposed (*EcSED*) is utilized and extended to contribute to the solution of the ISO insecurity management problem in the new deregulated framework. Indeed, nowadays, other tools are available to improve security: in particular the developments in power electronics allow a wide and effective use of *Flexible AC Transmission Systems* (FACTS) controllers. As consequence of this, the *EcSED* has been extended in order to take into account their presence. To do that, a transmission matrix model for *Unified Power Flow Controller* (UPFC), the most common and flexible FACTS controller, is proposed. A basic algorithm solving the aforesaid *EcSED* with inside UPFC is described, that allows alleviating computational efforts. Finally, case studies are provided for a test power system to show the UPFC contribute to the ISO insecurity costs management problem.

### I. Introduction

In a competitive market context, the three system segments (Generation, Transmission and Distribution) of an Electric Power System (EPS) pursue independent and sometimes mutually conflicting economic objectives [1, 2].

The Independent System Operator (ISO), as transmission service provider, still controls the whole transmission network and makes decisions according to market participants' contracts. Its major duty will be confined to having responsibility for system operation and guaranteeing as much as possible system security. Let us define power system security as the ability of the EPS to operate steady-state-wise within the specified limits of safety and supply quality following a contingency [6].

At this point, the ISO main problem is how to pursue its objectives taking into account the following features: (i) generation costs; (ii) contractual clauses among the different market agents, relevant, for example, to the supply of ancillary services or economic penalizations; (iii) insecurity costs related to the possible power system operating points, and (iv) further facilities based on new system components, such as *Flexible AC Transmission System* (FACTS) controllers, useful to mitigate likely security problems by controlling line power flows.

To face this problem, the model proposed by the authors in [3-5,7], called Economically correct Secure Economic Dispatch (*EcSED*), may be useful in a deregulated market scenario, considering simultaneously generation costs, ancillary procurements and insecurity costs within its objective function [8]. The key idea of the model is to determine the insecurity costs relevant to the current operating point by evaluating the minimum load curtailment (*MLC*), so as to remove an overflow or a voltage collapse (abnormal operating conditions) after a contingency and restore power system feasibility.

As said above, nowadays, in order to reduce power system insecurity costs, new corrective actions can be performed thanks to the developments in FACTS technology. Indeed, by use of FACTS controllers, line power flows can be changed in such a way that thermal limits are not exceeded, losses minimized, stability margins increased and contractual requirements fulfilled without generation re-dispatching. Moreover, last generation of FACTS controllers, based on

high power electronic technology, can be used in a corrective framework for their fast response.

The most common last generation FACTS controllers are the Static Synchronous Compensator (STATCOM), the Static Synchronous Series Compensator (SSSC) and the Unified Power Flow Controller (UPFC). Usually, STATCOM injects in shunt with the transmission line a current in quadrature with the bus voltage, while SSSC generates in series with the transmission line a voltage with controllable magnitude and in quadrature with respect to the current line. Since the power input must always equal the power output, if an electric energy source is missed, either SSSC or STATCOM cannot exchange real power with the ac system when working independently. On the contrary, when they jointly work as UPFC, the SSSC can exchange real power with the ac system since it is provided by the STATCOM at the common dc link. UPFC is so the most versatile and complex FACTS controller [9]. As said before, it consists of a STATCOM, connected in shunt with the transmission line, and a SSSC connected in series with the transmission line, connected each other by a common DC link that includes a storage capacitor. UPFC can independently and simultaneously control the active and the reactive power flow on transmission line so as to improve the steady state performance and the transient stability of an EPS.

One of the goals of this paper is so to investigate on how the above mentioned FACTS controllers can be included in the EcSED model, and how they can affect the EcSED solution and reduce the costs related to the EPS insecurity.

At this scope, a mathematical model for UPFC, which will be referred to as *UPFC transmission matrix model*, is derived. Furthermore, an opportune UPFC admittance matrix is easily calculated by means of the *UPFC transmission matrix model* and so incorporated into the steady state power flow equations. It has to be noted that it is very easy to determine the STATCOM and the SSSC transmission matrix model by removing the SSSC part and the STATCOM part respectively from the *UPFC transmission matrix model*.

To solve in an efficient manner the proposed EcSED model, with the included UPFC, it is necessary to opportunely change the algorithm proposed in [8]. In particular, for the dangerous contingencies selection, the *MLC* model has to be used to consider the effect of UPFC as a further corrective action in post-contingency state.

The paper is organized in further six sections. Section II describes the EcSED model for a vertically integrated framework. In Section III the EcSED model, modified for a deregulated framework, is explained in details. In Section IV the implementation of *UPFC transmission matrix model* and the associated UPFC admittance matrix and how it has been incorporated into EcSED are discussed. Section V illustrates the algorithm adopted to solve the EcSED model with the embedded UPFC. Finally, Section 6 demonstrates through some numerical tests how the EcSED model, opportunely modified, is able to take into account the corrective action of UPFC with the associated reduction of insecurity costs.

## II. Economically correct statement for security management in a vertically integrated scenario

Power system economic operation is achieved solving the classic Economic Dispatching (ED) problem, minimizing the generation costs while meeting Load Flow equations. Obviously, in order to obtain a feasible solution, i.e. meeting operating constraints (N-Security), inequalities constraints have to be satisfied too, thus obtaining the classic formulation of Feasible Economic Dispatching (FED).

In order to verify if the resulting FED operating point is secure with respect to a set of the next-contingencies, it is necessary to perform a N-1 steady state Security Analysis (SA) within it.

If FED operating point is insecure, it should be corrected to avoid out-of-limit conditions in post contingency state. Assuming that insecurities can be removed without changing system topology and composition, the operating point has to be corrected, for example, by re-scheduling the controllable system quantities, i.e. the contracted generation active powers.

Several approaches were proposed in literature to solve this problem [2], [4]-[7]. The main idea is to use an optimal power flow model with post-contingency constraints, in order to meet network operating limits also after any contingency.

Following this idea, the problem becomes a "Secure Economic Dispatch" (SED), later on denoted as "conventional SED".

$$\begin{aligned} H_{SED} = \min & H \\ & P_{g_o} \end{aligned} \quad \text{s.t.} \quad (1)$$

$$\begin{aligned} H &= F(P_{g_o}) \\ LF(P_{g_o}, U_o, X_o, P_o, Q_o) &= 0 \\ D(P_{g_o}, U_o, X_o, P_o, Q_o) &\leq 0 \\ LF_j(P_{g_o}, U_j, X_j, P_j, Q_j) &= 0 \quad \forall j=1, \dots, L \\ D_j(P_{g_o}, U_j, X_j, P_j, Q_j) &\leq 0 \quad \forall j=1, \dots, L \end{aligned}$$

In "conventional SED" no abnormal operating condition exists after any contingency and after possible generation corrections. Security is met, but how much does it cost?

The main idea of the authors, illustrated in [4], [5], is to use a new approach, said "non conventional SED", in which load curtailability and its related cost are taken into account. If an abnormal operating condition is left, after a contingency, it is possible to determine which amount of load power has to be curtailed at each node, so as to remove that overflow and recover feasibility in post contingency state.

The total amount of curtailed load power, for a given contingency  $j$ , can be evaluated by solving the associated Minimum Load Curtailment problem, *MLC<sub>j</sub>*.

$$\begin{aligned} MLC_j = \min & [P_j - P_o]^T \cdot [1] \\ & P_j \end{aligned} \quad \text{s.t.} \quad (2)$$

$$\begin{aligned} LF_j(P_{g_o}, U_j, X_j, P_j, Q_j) &= 0 \\ D_j(P_{g_o}, U_j, X_j, P_j, Q_j) &\leq 0 \end{aligned}$$

An *insecurity cost function* related to these corrective actions can then be defined as an expression of the above load

curtailments. Different cost functions for undelivered load can be assumed, e.g. linear, stepwise, hyperbolic [4]–[7]. In general, it can be written:

$$\text{cost}_j = f(\text{MLC}_j) \quad (3)$$

Anyway, the  $\text{MLC}_j$  does not account for the occurrence probability of the  $j$ -th contingency during the time interval  $t$  contingencies are referred to, because it assumes that the  $j$ -th contingency already occurred.

In consequence of this consideration, it is more economically correct to consider an *expected contingency cost*, instead of a simple cost, obtained by multiplying the expense related to the  $j$ -th contingency,  $\text{cost}_j$ , by the related occurrence probability,  $p_j$ , as follows:

$$E[\text{cost}_j] = p_j \cdot \text{cost}_j \quad (4)$$

Considering the whole set of the next-contingencies, the *insecurity cost* related to the power system operating point,  $Pg_o$ , can then be defined as:

$$G(Pg_o) = \sum_{j=1}^L E[\text{cost}_j] \quad (5)$$

The above insecurity cost function has so the meaning of load curtailments “*expected cost*”. As the occurrence probability of a contingency is small, the *expected cost* of the corrective load curtailments may then be less than the cost of the generation changes in intact system, determined by a conventional *SED*, necessary to avoid an abnormal operating condition. If so, the least cost corresponds to let the abnormal operating condition appear, then to curtail load: hence conventional *SED* is not economically completely satisfactory.

An “*economically correct*” statement for *SED* (*EcSED*) is so proposed as a *FED* problem in which the objective function is the sum of the conventional *FED*’s one and of the previously defined insecurity cost,  $G(Pg_o)$ .

$$\begin{aligned} H_{\text{EcSED}} &= \min H \\ &Pg_o \\ \text{s.t.} \quad &H = F(Pg_o) + G(Pg_o) \\ &LF(Pg_o, U_o, X_o, P_o, Q_o) = 0 \\ &D(Pg_o, U_o, X_o, P_o, Q_o) \leq 0 \end{aligned} \quad (6)$$

Obviously, the *EcSED* solution is always the best trade-off between whole security and minimum generation costs [4], [5].

### III. Economically correct statement for security management in a deregulated market scenario

Let us investigate how the ideas previously discussed could be adapted to the new needs and trends of the deregulated electricity market.

Within the various types of transactions that can be performed, one in particular is made by the ISO itself together with the other market participants: the system regulation transactions. System regulation is needed, for instance, to compensate for transmission losses and to

provide emergency power supplies. The aforesaid transactions are eventually needed to permit load dispatching among generation companies according to market rules and to assure, as much as possible, the  $N$  and  $(N-1)$  security.

Let  $P_{\text{Market}}$  be the operating state coming from market contracts between gencos and discos.

Assuming that the ISO has detected an insecurity due, for instance, to the likely occurrence of a contingency (hence dangerous contingency), it has to be investigated how can the ISO correct  $P_{\text{Market}}$ , by means of corrective and preventive actions, in order to preserve power system feasibility either in pre or in post contingency state.

What has been discussed about the validity of the *SED* model is furthermore valid in a deregulated environment. Indeed, if the ISO didn’t take into account the possibility of curtailing load, it would mean that the ISO would prefer to interfere with market contracts, altering them in order to guarantee security at any cost (that would result only in a generation cost due to the generation powers rescheduling), hence preventing the need of curtailments.

As an example, the Italian market policy shows that to guarantee power transactions security and reliability, the ISO has to eventually modify the power operating state,  $P_{\text{Market}}$ , hence yielding a cost which customers will be charged with [11]. From these considerations, it could seem that being variations of market contracts free for the ISO, the most economic action to correct  $P_{\text{Market}}$  must be power rescheduling, that is not “*economically correct*” for discos and gencos because it causes an increase of the energy cost. Hence, even if there is no expense for the ISO in changing the market operating point, the variations to market contracts must be the minimum, to preserve the economics of all market participants. This is the reason for which in *SED* and *EcSED* models a function cost exists that weights eventual  $P_{\text{Market}}$  modifications.

At this point, having understood that the best solution to the problem of the insecurity cost management is to find an economically convenient mix of curtailment and rescheduling actions, let us infer how the above *EcSED* model for a vertically integrated power system could be adapted to the new open market scenario.

It is opportune to underline that, in the new scenario, loads are classified according to their importance into two categories: curtailable (C) and firm (F). C-loads may involve residential and commercial sectors, while F-loads may involve, for instance, industrial sectors, large commercial consumers, hospitals, etc.

Usually, C-loads are shed from the less to the most important ones. If more than one load bus is equally qualified, the amount of power to be shed is divided among these buses according to some criterion. Also, whenever it is possible, residential loads are the first to be shed.

F-loads are curtailed after shedding all C-loads in a system or area. Usually, the amount of power to be curtailed from F-loads is shed among these loads according to some criterion: large industrial loads will be more affected than small industrial consumers. Priorities can also be assumed if some

sort of agreement or contract has been established a priori between industrial consumers and utility. In fact, any philosophy or policy for curtailing bus loads can be considered [9]. The main goal is always to minimize system interruption costs and it is quite well understood that the cost of the undelivered power is much higher than the purchasing price. As consequence of this, in the model the different loads behaviour, as far as their availability to be curtailed, may be stressed by using different load curtailment costs together with different load curtailment limits. Bearing in mind what has been discussed till now, let us explode (6) in the new market situation.

$$\begin{aligned}
 H_{EcSED} = \min H \\
 \Delta P_{g_o}, \Delta P_{g_j}, \Delta P_j \\
 \text{s.t.} \\
 \Delta P_{g_o} = P_{g_o} - P_{\text{Market}} \\
 \Delta P_{g_j} = P_{g_j} - P_{g_o} \\
 \Delta P_j = P_j - P_o \\
 H = F(\Delta P_{g_o}) + \sum_{j=1}^L p_j G(\Delta P_j) + \sum_{j=1}^L p_j F^{\text{post}}(\Delta P_{g_j}) \\
 LF(P_{g_o}, U_o, X_o, P_o, Q_o) = 0 \\
 D(P_{g_o}, U_o, X_o, P_o, Q_o) \leq 0 \\
 LF_j(P_{g_j}, U_j, X_j, P_j, Q_j) = 0 \quad \text{for every contingency } j \\
 D_j(P_{g_j}, U_j, X_j, P_j, Q_j) \leq 0 \quad \text{for every contingency } j
 \end{aligned} \tag{7}$$

It can be noticed that the variables of (7) have the same meaning as in (6). The  $EcSED$  solution, i.e.  $(\Delta P_{g_o}^*, \Delta P_{g_j}^*, \Delta P_j^*) = \text{argmin}(H_{EcSED})$ , is the set of the “economically correct” actions the ISO can implement to manage security, taking into account the economics of the power system. It is worth to explain the meaning of each decision variables vector in detail.  $\Delta P_{g_o}$  is the vector of the active generation powers corrections in pre-contingency state.  $\Delta P_{g_j}$  and  $\Delta P_j$  are respectively the vectors of the active generations powers corrections and of the active load power curtailed after contingency  $j$ , if needed.

In order to determine such variables by means of an economic criterion, the objective function of (7) is composed by three terms:

1.  $F(\Delta P_{g_o})$  represents the variation in cost due to a pre-contingency change in gencos contracts,  $\Delta P_{g_o}$ ;
2.  $\sum_{j=1}^L p_j G(\Delta P_j)$  is the insecurity cost to be met if  $P_o$  is perturbed in post-contingency state, owing to the occurrence of a contingency.  $\sum_{j=1}^L p_j F^{\text{post}}(\Delta P_{g_j})$

represents the expected cost of the variation due to a post-contingency generation powers change with respect to  $P_{g_o}$ .

In general,  $F^{\text{post}}$  is different from  $F$ : in post contingency state the generation power the ISO has to buy from gencos should be paid at a lower cost than in pre-contingency state, being it a need to be eventually met only if a contingency

really occurs. It can be noticed that 2 and 3 can be considered as ancillary services procurement costs, while 1 can be seen as the cost gencos and discos must meet for system security.

In consequence of the chosen objective function, it is necessary to include, besides pre-contingency constraints, also post contingency ones.

This represents a real drawback from a computational point of view. Indeed, even if only one contingency should result dangerous, f.i.  $j$ , all constraints related to all contingencies have to be put into the model in order to correct the unfeasibility caused by  $j$ . This greatly increases the size of the model to be solved, thus worsening the computational process.

#### IV. UPFC transmission matrix model

As well known, the possibility of controlling power flows in an electric power system without generation rescheduling or topology changes can improve power system security and performance. Investigating the power flow through a transmission line shows that the control of the nodal voltages magnitude, of the nodal voltages phase and of the impedance of a transmission line are effective means for power flows control in AC transmission systems. By use of controllable components, line power flows can be so opportunely changed in such a way that thermal limits are not exceeded, losses minimised and contractual requirements fulfilled, without violating the economic generation dispatch. However, power flows in a network are not easily controlled because line parameters cannot be easily changed. Recent advances in high power technology have allowed implementing power electronic based devices, referred to as FACTS controllers, which can provide the needed flexibility in controlling system power flows [13-15]. FACTS controllers are superior to mechanically switched systems since they can operate fast and with a very high duty cycle.

FACTS controllers can be used for shunt, series, series/shunt and phase compensation. The controllers that can be used for these functions are respectively:

- » Static Synchronous Compensator (STATCOM);
- » Static Synchronous Series Compensator (SSSC);
- » Unified Power Flow Controller (UPFC).

In particular, UPFC can provide more than the others, but naturally at a higher cost, the necessary functional flexibility for power flows control. Always within physical limits, UPFC can thus be used to move power from weaker circuits to stronger ones. Doing it, it should therefore be possible to achieve improved power transfers over existing lines.

UPFC consists of two voltage source converters (VSCs), operating from a common dc link provided by a dc storage capacitor (Fig.1). One converter, in particular, is connected in series with the transmission line via a series boost transformer with a leakage reactance  $X_{se}$ , operating as a SSSC. The other converter is connected in shunt with the transmission line via a shunt boost transformer with a leakage reactance  $X_{sh}$ , operating as a STATCOM. It has to be underlined that the main objective of the series converter is to control the active



and reactive power flows on the transmission line, by regulating magnitude and phase of the output voltage. Instead, the principal control function of the shunt converter is to provide the eventually required active power by the series converter through the dc link terminals. In this way, the real power freely flows between the shunt and the series ac terminals, via the common dc link, and the net active power interchange between UPFC and power system is zero in steady state. Moreover, the shunt converter can independently supply/absorb reactive power in order to provide voltage regulation at the connection point.

Representing the effect of the two VSCs in terms of voltage source controllable in magnitude and in phase,  $\bar{E}_{se}$  and  $\bar{E}_{sh}$  respectively, the equivalent circuit of UPFC, shown in fig. 2, can be obtained. Using this UPFC representation it is possible to value the impact of the UPFC in the steady state power flow model.

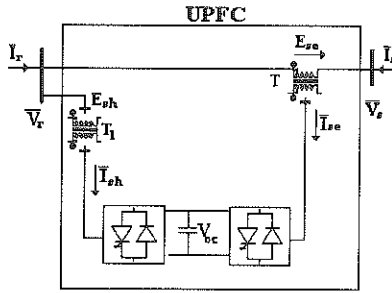


Fig. 1. UPFC scheme.

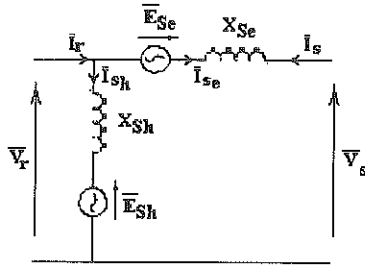


Fig. 2. UPFC equivalent circuit.

The  $\bar{E}_{se}$  and  $\bar{E}_{sh}$  can be exploded in terms of UPFC control variables as follows:

$$\begin{aligned}\bar{E}_{se} &= m_{se} \bar{V}_r e^{j\phi_{se}} \\ \bar{E}_{sh} &= m_{sh} \bar{V}_r e^{j\phi_{sh}}\end{aligned}\quad (8)$$

with  $0 \leq m_{se} \leq m_{se}^{\max}$ ,  $0 \leq m_{sh} \leq m_{sh}^{\max}$ ,  $-\pi \leq \phi_{se} \leq \pi$ ,  $-\pi \leq \phi_{sh} \leq \pi$ .

Applying Kirchoff laws on circuit in Fig. 2, the following expressions can be written:

$$\begin{cases} \bar{V}_r = \bar{V}_s - \bar{E}_{se} - jX_{se}\bar{I}_s \\ \bar{I}_r = \bar{I}_{sh} - \bar{I}_s \\ \bar{V}_r = \bar{I}_{sh}jX_{sh} + \bar{E}_{sh} \end{cases}\quad (9)$$

Using (8) and after some algebraic manipulations, (9) becomes the following:

$$\begin{cases} \bar{V}_r = \bar{V}_s - m_{se} e^{j\phi_{se}} \bar{V}_r - jX_{se} \bar{I}_s \\ \bar{I}_r = \bar{V}_r \frac{1 - m_{sh} e^{j\phi_{sh}}}{jX_{sh}} - \bar{I}_s \end{cases}\quad (10)$$

or, in a more effective form,

$$\begin{cases} \bar{V}_r = \frac{1}{1 + m_{se} e^{j\phi_{se}}} \bar{V}_s - \frac{jX_{se}}{1 + m_{se} e^{j\phi_{se}}} \bar{I}_s \\ \bar{I}_r = \frac{1 - m_{sh} e^{j\phi_{sh}}}{1 + m_{se} e^{j\phi_{se}}} \frac{1}{jX_{sh}} \bar{V}_s + \left( -1 - \frac{1 - m_{sh} e^{j\phi_{sh}}}{1 + m_{se} e^{j\phi_{se}}} \frac{X_{se}}{X_{sh}} \right) \bar{I}_s \end{cases}$$

It is so possible to associate the following transmission matrix  $\dot{H}$  to the UPFC equivalent circuit:

$$\begin{bmatrix} \bar{V}_r \\ \bar{I}_r \end{bmatrix} = \dot{H} \begin{bmatrix} \bar{V}_s \\ \bar{I}_s \end{bmatrix}\quad (11)$$

$$\dot{H} = \begin{bmatrix} \dot{H}_{rr} & \dot{H}_{rs} \\ \dot{H}_{sr} & \dot{H}_{ss} \end{bmatrix} =$$

$$= \begin{bmatrix} \frac{1}{1 + m_{se} e^{j\phi_{se}}} & -\frac{jX_{se}}{1 + m_{se} e^{j\phi_{se}}} \\ \frac{1 - m_{sh} e^{j\phi_{sh}}}{1 + m_{se} e^{j\phi_{se}}} \frac{1}{jX_{sh}} & -\left( 1 + \frac{1 - m_{sh} e^{j\phi_{sh}}}{1 + m_{se} e^{j\phi_{se}}} \frac{X_{se}}{X_{sh}} \right) \end{bmatrix}$$

(11) can be rewritten in terms of admittance matrix as follows:

$$\begin{bmatrix} \bar{I}_r \\ \bar{I}_s \end{bmatrix} = \dot{Y} \begin{bmatrix} \bar{V}_r \\ \bar{V}_s \end{bmatrix} \quad \text{with:}\quad (12)$$

where:

$$\dot{Y} = \begin{bmatrix} \dot{Y}_{rr} & \dot{Y}_{rs} \\ \dot{Y}_{sr} & \dot{Y}_{ss} \end{bmatrix} = G + jB$$

$$\dot{Y}_{rr} = \frac{(1 + m_{se} e^{j\phi_{se}}) + \frac{X_{se}}{X_{sh}} (1 - m_{sh} e^{j\phi_{sh}})}{jX_{se}}$$

$$\dot{Y}_{rs} = \frac{1 - m_{sh} e^{j\phi_{sh}}}{1 + m_{se} e^{j\phi_{se}}} \frac{1}{jX_{sh}} + \left( \frac{j}{X_{se}} + j \frac{1 - m_{sh} e^{j\phi_{sh}}}{1 + m_{se} e^{j\phi_{se}}} \frac{1}{X_{sh}} \right)$$

$$\dot{Y}_{sr} = j \frac{1 + m_{se} e^{j\phi_{se}}}{X_{se}}$$

$$\dot{Y}_{ss} = -\frac{j}{X_{se}}$$

Let  $P_{se}$  be the active power supplied/ absorbed by the series controllable voltage source  $\bar{E}_{se}$ :

$$P_{se} = \text{Re}[\bar{E}_{se} I_{se}^*] = \text{Re}[m_{se} V_r e^{j(\varphi_r + \varphi_{se})} I_{se}^*] \quad (13)$$

Being the expression of the current  $\bar{I}_{se}$  the following:

$$\bar{I}_{se} = \frac{\bar{E}_{se} + \bar{V}_r - \bar{V}_s}{jX_{se}}$$

(13) becomes:

$$P_{se} = \frac{V_r m_{se}}{X_{se}} (-V_r \sin \varphi_{se} + V_s \sin(\varphi_{se} + \varphi_r - \varphi_s)) \quad (14)$$

Let  $P_{sh}$  be the active power supplied/ absorbed by the shunt controllable generator  $\bar{E}_{sh}$ :

$$P_{sh} = \text{Re}[\bar{E}_{sh} I_{sh}^*] = \text{Re}[m_{sh} V_r e^{j(\varphi_r + \varphi_{sh})} I_{sh}^*] \quad (15)$$

Being the current  $\bar{I}_{sh}$ :

$$\bar{I}_{sh} = \bar{V}_r \frac{(1 - m_{sh} e^{j\varphi_{sh}})}{jX_{sh}},$$

(15) becomes:

$$P_{sh} = \frac{m_{sh} V_r^2}{X_{sh}} \cos\left(\varphi_{sh} + \frac{\pi}{2}\right) = -\frac{m_{sh} V_r^2}{X_{sh}} \sin \varphi_{sh} \quad (16)$$

Since in steady state the net active power interchange of UPFC with the power system has to be equal to zero, the following equality holds:

$$P_{se} - P_{sh} = 0 \quad (17)$$

Replacing (14) and (16), (17) becomes:

$$\begin{aligned} & V_r m_{se} \frac{1}{X_{se}} (-V_r \sin \varphi_{se} + V_s \sin(\varphi_{se} + \varphi_r - \varphi_s)) \\ & + m_{sh} \frac{1}{X_{sh}} V_r^2 \sin \varphi_{sh} = 0 \end{aligned} \quad (18)$$

UPFC can be easily taken into account in load flow equations by modifying power system admittance matrix considering (12) and adding (18) as further constraint to be satisfied. The control variables are  $m_{se}$ ,  $m_{sh}$ ,  $\varphi_{se}$  and  $\varphi_{sh}$  and their values have to be chosen according to an objective function.

The *EcSED* model in presence of UPFC becomes so the following:

$$\begin{aligned} & H_{ECSED} = \min H \\ & \Delta P_{go}, \Delta P_{gj}, \Delta P_j \\ & \text{s.t.} \\ & \Delta P_{go} = P_{go} - P_{Market} \\ & \Delta P_{gj} = P_{gj} - P_{go} \\ & \Delta P_j = P_j - P_o \\ & H = F(\Delta P_{go}) + \sum_{j=1}^L p_j G(\Delta P_j) + \sum_{j=1}^L p_j F^{post}(\Delta P_{gj}) \\ & LF'(P_{go}, U_o, X_o, P_o, Q_o, m_{se}, m_{sh}, \varphi_{se}, \varphi_{sh}) = 0 \\ & M(m_{se}, m_{sh}, U_o, \varphi_{se}, \varphi_{sh}) = 0 \\ & D(P_{go}, U_o, X_o, P_o, Q_o) \leq 0 \\ & \text{for every contingency } j \end{aligned} \quad (19)$$

$$LF'(P_{gj}, U_j, X_j, P_j, Q_j, m_{sej}, m_{shj}, \varphi_{sej}, \varphi_{shj}) = 0$$

$$D_j(P_{gj}, U_j, X_j, P_j, Q_j) \leq 0$$

$$M_j(m_{sej}, m_{shj}, U_j, \varphi_{sej}, \varphi_{shj}) = 0$$

Let us denote with  $LF'$  the load flow equations obtained incorporating equation (12) in the admittance matrix of the power system and with  $M$  the UPFC constraint described by (18).

It is obvious that even if the UPFC control variables are not directly considered in the objective function, they affect load flows in the power system, so as to prevent overflow and/or voltage collapse.

In this way,  $(\Delta P^*_{go}, \Delta P^*_{gj}, \Delta P^*_j, m^*_{se}, m^*_{sh}, \varphi^*_{se}, \varphi^*_{sh}, m^*_{sej}, m^*_{shj}, \varphi^*_{sej}, \varphi^*_{shj})$  represents the new set of the “economically correct” actions in presence of UPFC the ISO can adopt to manage security.

It is worth to underline that this model for the UPFC case can be easily adapted for STATCOM or SSSC cases just removing the SSSC part and the STATCOM part respectively from the *UPFC transmission matrix model*. Obviously, for the SSSC and STATCOM models the number of control variables is reduced and, consequently, the effectiveness in power flow control.

## V. Algorithm for *EcSED* solution in presence of UPFC

Referring to the proposed model, illustrated in (19), it is very easy to note that the number of variables and constraints to be considered is enormous for real life networks [5]. Then a simple algorithm is presented below that is able to reduce the size of the problem, thus speeding up the computational process. The main idea consists in selecting those contingencies that occurring may cause an overflow or a voltage collapse (dangerous contingencies), before performing the *EcSED* solution, and putting only their associated constraints and variables into the model. What has been described is only a step of a more detailed algorithm that works as follows:

1. Solve *FED* within the market operating point,  $P_{Market}$ , thus obtaining  $P_{go}$ . Initialize A, i.e. the set of the next-contingencies to be checked and set D (set of dangerous contingencies) to empty.
2. If A is empty, go to 6. Otherwise, perform a Security Analysis within the operating point  $P_{go}$  ( $\Rightarrow$  dangerous contingencies selection).
3. Optimality test: is there any new dangerous contingency (new with respect to the ones already previously selected)? If yes withdraw contingencies detected dangerous from A, put them in D and go to 4. Otherwise go to 6.
4. *EcSED* model building by including the constraints and the relevant decision variables associated to contingencies belonging to D. Set D to empty.
5. *EcSED* model solution ( $\Rightarrow$  optimal  $P^*_{go}, P^*_{gj}, P^*_j, m^*_{se}, m^*_{sh}, \varphi^*_{se}, \varphi^*_{sh}, m^*_{sej}, m^*_{shj}, \varphi^*_{sej}, \varphi^*_{shj}$ ). Is the pre-contingency operating point  $P^*_{go}$  equal to the one

obtained in the previous iteration? If yes, go to 6. If not  $P_{g0} = P^*_{g0}$  go to 2.

6. End.

Referring to step 1,  $P_{g0}$  has to be determined to account for losses by solving a FED problem starting from  $P_{Market}$ .

In order to achieve computational advantages, in previous instance Security Analysis has been performed using a Super Decoupled Load Flow within  $P_{g0}$ : if an overflow or a voltage collapse exists after the occurrence of the  $j$ -th contingency, then this contingency is assumed dangerous and the relevant set of post-contingency constraints is put into the *EcSED* model. For further details see [8].

This algorithm can become ineffective when *EcSED* has to be solved in presence of UPFC. Indeed, using a simple load flow, the effect of UPFC as corrective action is not taken into account. It may so happen that a contingency can be considered dangerous while, for the effective UPFC regulation, such a contingency could become not dangerous.

In order to verify if a contingency is really dangerous or not, it is more opportune to solve a *MLC* problem including an UPFC. Indeed, solving the *MLC* problem, the UPFC control variables are determined so as to reduce load curtailments necessary to restore power system feasibility in post contingency state. However, the computational time increases since *MLC* requires more computational time than Super Decoupled Load Flow.

For this reason the previous algorithm has been modified in order to select the “really dangerous” contingencies in presence of UPFC trying to further minimize computational time. At this scope, in a first instance, a Super Decoupled Load Flow is used to determine dangerous contingencies (subset  $D$ ); then an *MLC* is solved for every contingency belonging to  $D$ , in order to identify the “really dangerous” contingencies ( $D'$ ). Only for contingencies in  $D'$  the corresponding set of post contingency constraints is added to the *EcSED* model.

These two level contingencies selection notably speeds up the computational process because, in general, only a little percent of contingencies is “really dangerous”.

From here, the algorithm solving *EcSED* in presence of UPFC changes as follows:

1. Solve *FED* within the market operating point,  $P_{Market}$ , thus obtaining  $P_{g0}$ . Set  $A$  and  $D$  to empty, i.e. the set of the-next-contingencies to be checked and the set of dangerous contingencies, respectively.
2. If  $A$  is empty, go to 7. Otherwise, first level of dangerous contingency selection: perform a Security Analysis within the operating point  $P_{g0}$  by means of a Super Decoupled Load Flow ( $\Rightarrow$  dangerous contingencies selection).
3. Optimality test: is there any new dangerous contingency (new with respect to the ones already previously selected)? If yes put them into  $D$  and go to 4. Otherwise go to 7.

4. Second level of dangerous contingency selection: solve a *MLC* for every contingency belonging to  $D$ , put only the “real dangerous” in  $D'$  and withdraw them from  $A$ . Set  $D$  to empty.

5. *EcSED* model building, by including the relevant constraints and decision variables related to contingencies belonging to  $D'$ . Set  $D'$  to empty.

6. *EcSED* model solution ( $\Rightarrow$  optimal  $P^*_{g0}$ ,  $P^*_{gj}$ ,  $P^*_j$ ,  $m^*_{se}, m^*_{sh}, \phi^*_{se}, \phi^*_{sh}, m^*_{sej}, m^*_{shj}, \phi^*_{sej}, \phi^*_{shj}$ ). Is the pre-contingency operating point  $P_{g0}$  equal to the one obtained in the previous iteration? If yes, go to 7. If not,  $P_{g0} = P^*_{g0}$  and go to 2.

7. End.

Anyway, it has to be underlined that, even though the proposed algorithm allows improving the *EcSED* solution time, a faster procedure should be planned seen that it would be important to use *EcSED* on-line.

## VI. Numerical Results

In order to illustrate how the proposed *EcSED* model works in presence of UPFC, some numerical tests on a simple five bus test power system, shown in Fig.3, have been carried out.

As to the objective function,  $F$ ,  $F^{Post}$  and  $G(\Delta P_j)$  have been assumed linear versus  $\Delta P_{g0}$ ,  $\Delta P_{gj}$  and  $\Delta P_j$  respectively. The corresponding pre and post-contingency rescheduling and curtailment cost coefficients (Monetary Unit=M.U.),  $rc_0$ ,  $rc_j$ ,  $sc_j$ , are shown in Table I, together with the maximum generation power rescheduling in pre and post-contingency state and the maximum available load curtailment ( $\Delta P_{g0}^{Max}$ ,  $\Delta P_{gj}^{Max}$  and  $\Delta P_j^{Max}$ , respectively). Several tests have been performed for different system parameters values to evaluate the sensitivity of *EcSED* solution versus them. Obviously, results strictly depend on the chosen market operating point,  $P_{Market}$ .

The set of-the-next-contingencies is constituted by one line outage a time. The occurrence probability,  $p_j$ , of each contingency  $j$  is assumed equal to 0.01.

As to results, they are presented in the following order: for each experiment, firstly those ones obtained for the test power system without UPFC; then the ones obtained with an UPFC installed on line (1), with STATCOM installed at node 1 and SSSC between nodes 1 and 1', as shown in Fig. 4. For sake of simplicity, three different relevant tests are reported in the paper, in order to illustrate the effectiveness of the proposed approach.

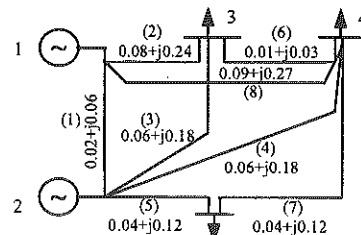


Fig.3. Test power system (1 to 4: buses, (1) to (8): lines)



### D- Computational time results

As to computational performance, the proposed algorithm allows to reduce time computing. Indeed, it is possible to obtain a speed up of 4 times in comparison with the time taken to solve an *EcSED* containing all contingencies as in (12). Moreover, it has to be observed that thanks to the two level security analysis of the algorithm, a speed up of 1.3 times is also reported in comparison with the time taken with a security analysis performed directly with the *MLC* solution for each contingency.

### Conclusions

The main aim of the paper has been to extend an *Economically correct Secure Economic Dispatching* model, in the new deregulated framework, in order to take into account FACTS devices.

Indeed, in order to further reduce power system insecurity costs, new corrective actions can be performed thanks to the developments in FACTS technology. At this scope, a transmission matrix model for Unified Power Flow Controller (UPFC), the most common and flexible FACTS controller, is proposed. By use of FACTS controllers, line power flows can be changed in such a way that thermal limits are not exceeded, losses minimised, stability margins increased and contractual requirements fulfilled, decreasing generation re-dispatching.

In such a way, the proposed *EcSED* model is able to provide the optimum mix of preventive and corrective actions to improve N and N-1 security problem, according to economic criteria.

Furthermore, an efficient algorithm to solve the proposed model has been illustrated to reduce computational efforts.

Finally, some numerical results are provided for a simple test power system. From these results it can be observed that the presence of an UPFC improves the ISO insecurity costs management in a deregulated market scenario, considering the UPFC modulation as further ancillary service.

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### Biographies

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## The evolution of the OPF functions for the Security assessment in a competitive market structure

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### Summary

The liberalisation of electric energy markets is introducing important changes in the economic and technical aspects of power system design and control. A deep restructuring of the policies adopted both in planning and operation is needed. As a consequence, significant improvements in the models and the algorithms for power system optimisation are under way. In spite of the transition from the vertically integrated structures of the past to the free competition in the electricity market, OPF maintains a central role in the procedures employed for short and mid term operation of electric systems: in the new environment, this issue will be covered by ISO (or TSO), with a different role, depending on the particular market structure adopted (bilateral/pool).

The paper analyses the objectives to be pursued in the optimisation programs and the constraints related to the maintainment of the quality and security performances at levels comparable with the past.

In competition with the traditional (minimum production cost) strategies, other objective functions are proposed.

A first application focusses on the correct management of all the transactions (both in bilateral and pool arrangements), by adding new terms to the objective function of a traditional OPF. Further studies are devoted to the problem of congestion relief: in this case, new control tools (i.e. FACTS devices) or correct economical signals related to nodal prices are introduced. In the programs presented, transmission security constraints can be handled in a corrective or preventive way, depending on their impact on the price of electric energy.

As the above technical and economic requirements could give rise to mutual conflict, an adequate handling of the related constraints forces the ISO to adopt proper decision techniques. To this aim, the use of Multiobjective Optimisation (MO) is envisaged. MO allows the management of different objectives and makes it easier to take a decision, as it gives indications on the consequences of the choice with respect to all the objective functions considered.

Some applications of the proposed procedures to IEEE and CIGRE test system are described in the paper.

### 1. Introduction

In the vertically integrated systems, the OPF procedures were strongly characterised by the possibility of the Monopolist (ENEL for the Italian system) to manage both the generation pattern and the transmission system (by means of a Central Dispatcher, CD), with the goal of minimising the overall

system costs, complying with the obligation to supply the requested power to all the users at a predefined tariff and quality level [1].

The incoming scenario introduces new duties and objectives for the traditional dispatcher, which is now an Independent System Operator (ISO). In the market environments, the aim of ISO is to allow a fair competition on the generation side, without losing the quality and the security of the supply to the final customers: these economic principles are forcing significant modifications in the algorithms and procedures used for OPF calculations.

In particular, new tools that allow the system operator to manage the system, complying with the rules of the electricity market and with the security requirements, must be available. These tools should be suitable for a transparent and non discriminatory operation of the system, as ISO is responsible for the security of the system and can modify the dispatch (unconstrained/preferred scheduling), resulting by the auction mechanism, only if some security problems are present. Furthermore, the ISO prerogatives are much different in the Pool structure and in the Bilateral Contract organisation. If only Bilateral Contracts are operating, the ISO responsibilities are limited to the security assessment and enhancement (congestion management in the transmission grid) [2].

In the Pool model the ISO maintains (with some limitations), the responsibility for security and economy. Typically, an auction market structure is operating, with both supply offers and demand bids: the ISO (directly, or by means of the Power Exchange, PX) determines the set of offers and bids accepted [3]. The ISO/PX aim is to find the optimal solution by solving again an economic dispatch problem, as CD did, taking into account the network constraints. The congestion problem can be solved implicitly as part of a new SCOPF model, by determining a security constrained schedule. Advanced security constrained optimal power flow (SCOPF) models are presented in the paper.

One of them can be employed in a bilateral contract environment for optimising (maximising/minimising) the real power exchanges among the different agents of the electricity market, by taking into account the existing transmission commitments, the priority of the transactions, the prices of the bidders and the desired security level. The contingency constraints can be handled in a preventive or in a corrective way, depending upon the nature of the transaction (firm or interruptible) and on the costs of the rescheduling actions needed for maintaining the desired security level [4].

In a different SCOPF procedure, tailored to a pool model, the demand at each bus can be a variable [5] depending on the

willingness of the customer to pay a certain price for a given level of served load. The willingness to pay of the customer at bus  $k$  can be expressed through a decreasing function (the demand bid curve) that indicates the unit energy price (marginal price). This OPF model is characterized by a composite objective function with two terms, the final user benefits and the total production costs, whose difference represents the so-called social surplus [6]. If the network constraints are neglected (or they are not active at optimal point), the Market Clearing Price (MCP) is unique for the whole system. On the contrary, if the network constraints are considered and some of them are active at the optimal point, congestion can arise causing, along with losses, a different optimum, with a lower level of social surplus: in this situation a single MCP no longer exists, and the system can be split into zones, each with a different Zonal Incremental Cost (ZIC). Congestions may result in certain cases in market price volatility [7] and may lead to price spikes. It is worth noticing the impact of the security enhancement on the energy nodal (zonal) prices at different location of the system. The possibility of overcoming congestions by means of other control variables (in addition to the traditional generation rescheduling procedures) is investigated.

In a third SCOPF procedure implemented, the adequacy of some new control variables was tested: in particular, Flexible Alternate Current Transmission Systems (FACTS) [8] have been modeled. Even if the most practical applications of these devices have been devoted, until now, to the exploitation of their dynamic performances, it is very important to highlight their capability to solve the network congestion problems in a transmission open access environment. Therefore, this paper considers only the steady-state model of two FACTS devices (the Series Power Flow Control, SPFC, and the Thyristor Controlled Phase Angle Regulator, TCPAR) [9][10]. A detailed analysis of the Lagrange multipliers associated to active constraints in the optimal point shows the impact of FACTS devices on the marginal price of the energy at the different busses of the power system.

New solutions (different from the ones obtained by standard optimisation methods) can be provided by MO methodologies: their exploitation is suggested in the paper [11]. The intermediate results deriving by MO are not unique, but provide an infinite set of optimal solutions, namely the Pareto set (PS). For each point belonging to the PS, the improvement in one of the objectives results in the worsening of at least another objective [12].

Therefore, to solve a MO problem, it is necessary to define the useful objectives, find the Pareto set and, at the end, choose a solution from that set. The final solution depends on the point of view of the decision maker [13], who has to take into account the relative importance of the conflicting objectives. This paper presents the features of the MO techniques than can be of interest for modern ISOs in the short-term environment.

The adequacy of the new OPF tools to support the ISO decision in the short term operation of a market structure are demonstrated in the paper by simulations performed on IEEE and CIGRE test systems.

## 2. Optimal Transaction Scheduling

The difference between the market-operated electric systems and the Vertically Integrated Utilities (VIU) of the past (see following figure 1) is the presence of various operators: on the generation side (IPPs, Independent Power Producers, and GenCos, Generating Companies) have an open access to the transmission grid. The competitive market scenario includes also Traders and Distributor Companies (DisCos), who are serving the final customers.

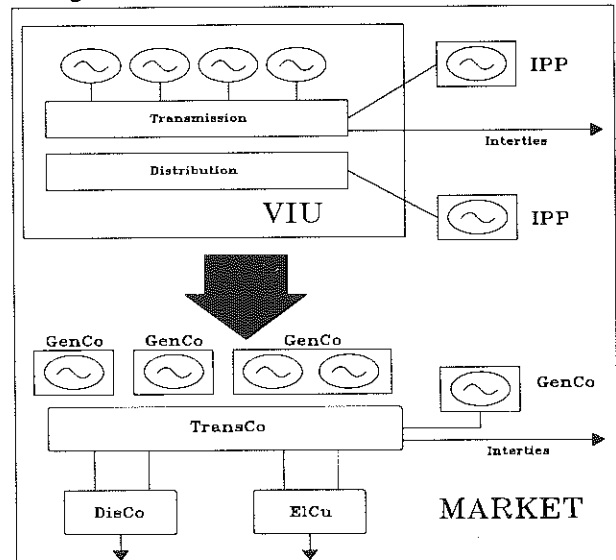


Fig. 1. Transition from VIU to a restructured system.

On the demand side, some major loads are defined Eligible Customers (ElCus): they are allowed to subscribe bilateral contracts for their supply, or to buy power through the Power Exchange (PX); the remaining load (Captive Customers) is supplied by DisCos. Typically, each DisCo is in charge of the supply in a specific area; nevertheless, within the same area, different transactions are likely to arise:

- ♦ power plants belonging to IPPs can compete for the generation in the whole market;
- ♦ ElCu load plants may receive their supply (via bilateral contracts) by generators belonging to any area of the system.

An example of a possible Objective Function (OF) for the new OPF in the system depicted above can be found in the market strategies of the Generating Companies: the common target of the different GenCos and IPPs is to sell as much energy as they can with the highest possible profit. Beside the auction mechanism (related to the bids submitted by each operator) also transmission technical constraints may result in limitations to the commercial strategies of each competitor. Therefore, companies with an easier access to the grid and with lower production costs will take advantage in the new environment. The OPF model proposed in [4] can be used as a provisional tool of the system behavior, and can be adopted by the ISO to assess the feasibility of the scheduled transactions.

The referred procedure provides the possibility of investigating about the effects of the transmission of power from a single bus of the system (e.g. the bus equipped with generators belonging to an IPP) to a different area of the system, or even to another bus, located apart in the system, representing the load (EICu) to be supplied by the IPP. The relevant transactions (that can be seen as control variables of the problem, or as further constraints) are modeled both as firm and interruptible contracts.

The IEEE 73 bus Reliability Test System (RTS-96) [14] is used for the tests. The system is an extension of the standard 24 bus test system, which has been duplicated twice in order to form 3 areas interconnected by 5 tie lines. Three tie lines directly interconnect area A and area B, the other two lines close the loop by linking areas C to area A and area B to area C. This network has been utilised by the CIGRE Task Force 38.04.02 for the determination of the maximum transfer capacity among different areas [15]. A 600 MW firm transaction contract is established between area A (exporting) and area B (importing). Area C is operated in autonomy and can act as a wheeling agent. The total power exchange with the neighboring areas is fixed at zero. Several forms of deregulated environment are tested in the analyses performed with this system.

The introduction of an IPP in area A and of an eligible consumer in area C allows us to define three different scenarios (depicted in figure 2), with the same network topology and resource allocations (load and generation), but with different agents.

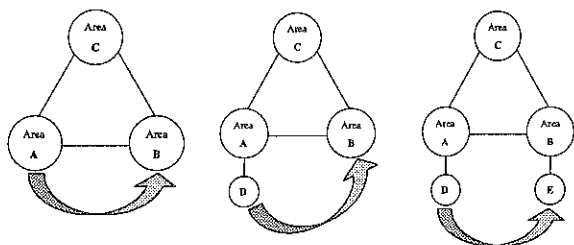


Fig. 2. Three test system scenarios

- In the first scenario three control areas (A, B, C) are defined. The TSO (Transmission System Operator, as the ISO is also the network owner) has to satisfy the obligation of the 600 MW firm transaction between areas A and B. In addition to this firm import contract, areas B and A are interested in maximising the real power exchange between them. In this scenario (*area to area transfer*) the maximum amount of power imported by area B is the main objective of the SCOPF.

- In the second scenario a new agent is introduced, assumed to be an independent power producer, owner of the generators at two specific buses within area A. This IPP is pointed out as area D in figure 2. In addition to the firm transaction of 600 MW, the ISO must comply with a second transaction scheduled by areas D and B. In this scenario (*point to area*), the SCOPF procedure aims to maximize the amount of real power that area B can purchase from area D.

- In the third scenario, an eligible consumer represents the new agent (area E) in the electricity market. Beside the firm transaction of 600 MW defined previously, a second transaction is scheduled between the IPP (area D) and the eligible consumer (area E). In this last scenario (*point to point*), the maximum amount of power that the IPP can sell to the eligible consumer is the main goal of the SCOPF.

Area C is operated in autonomy, minimising its operational costs and acting as a wheeling among the other agents in the market. The generation capacity and the load demand of the areas in the different scenarios are shown in Table 1.

|        | GENERATION CAPACITY [MW] |              |               | LOAD [MW]   |              |               |
|--------|--------------------------|--------------|---------------|-------------|--------------|---------------|
|        | Area - area              | Point - area | Point - point | Area - area | Point - area | Point - point |
| AREA A | 4304                     | 3544         | 3544          | 2433        | 2433         | 2433          |
| AREA B | 4247                     | 4247         | 4247          | 3920        | 3920         | 3210          |
| AREA C | 3795                     | 3795         | 3795          | 2850        | 2850         | 2850          |
| AREA D |                          | 760          | 760           |             | 0            | 0             |
| AREA E |                          |              | 0             |             |              | 710           |

Table 1. Data for the three test system scenarios.

Contingency constraints are taken into account in the SCOPF model. Different solutions of the SCOPF have been obtained by using three security levels (N, N-1 preventive, N-1 corrective) and two assumptions concerning the priority of transactions (firm or interruptible). As for corrective rescheduling, the maximum rate of change of thermal unit MW output is fixed in additional dynamic constraints. The upper bounds on current flows in N-1 preventive security are 10% higher than the rating used in normal state and in corrective security. The generation costs are assumed as second order polynomial convex functions. The results of the optimisation studies are depicted in figures 3 and 4. In the attainment of the main objective (the maximisation of the power exchanges), figure 3 shows an additional (beside the 600 MW of the firm transactions) amount of about 800 MW of import for Area B in the N security case and for the *area to area* scenario.

In the *point to area* and *point to point* scenarios the power sales of the IPP in area D can attain values of about 670 MW in a N security operation. In the *point to point* scenario, the consumer in area E must purchase the extra 40 MW from power producers in area B for the satisfaction of his demand. As an alternative a load shedding of 40 MW is required. The satisfaction of N-1 security requires a large reduction of the power exchanges both in the preventive and in the corrective case, if the scheduled transactions are considered firm. The lower values for the corrective cases are a consequence of the relaxed upper limits on current flows. The assumption of non-firm transactions allows higher values of the power exchanges in the normal state. The transactions scheduled for the normal operating state are considered interruptible and can be lowered in contingency cases. Therefore, the corrective rescheduling aims to precisely satisfy the limits on maximum current flows after the contingency event. The power sales of the IPP in area D are limited by the N-1 security requirements deriving from the outages of the transmission lines near the generation busses. The hourly costs, given in an arbitrary monetary unit



€/h in figure 4, are very expensive in all the scenarios for the preventive N-1 security solutions. The *point to area* and the *point to point* solutions are more costly due to the higher value of the generation costs of the IPP with respect to the other units of area A.

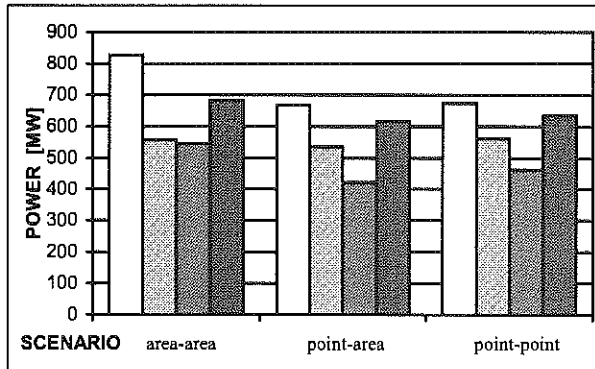


Fig. 3. Power exchanges for the three scenarios

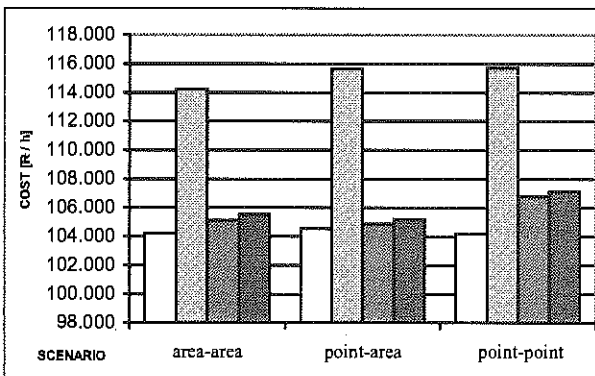


Fig. 4. Different cost values for the three scenarios.

**Caption:**

- N Security
- N-1 Preventive Security
- N-1 Corrective Security (interruptible contracts)
- N-1 Corrective Security (firm contracts)

The corrective secure solutions present costs slightly higher than the N secure operation.

### 3. Impact of congestions in a two sided auction market

In a further OPF procedure implemented [5], it is assumed that the demand at each bus can be a variable which depends on the willingness of the customer to pay a certain price for a given level of served load. The power demands at the single bus can be fixed at a predefined value or responsive to the prices of the furnished energy amount (elastic demand).

The willingness to pay of the customer at bus  $k$  can be expressed through a positive linearly decreasing function (the

demand bid curve) that indicates the unit energy price  $p_{dk}$  (marginal price) at which the customer will pay a given amount of power  $D_k$ .

The new OPF is characterized by a composite objective function with two terms, the total benefits for the users and the total revenues of the producers, whose difference represents the so-called *social surplus*. If losses and network constraints are not considered (or they are not active at the optimal point), the solution of the optimisation problem is characterized by a certain value of social surplus. In this situation the market clearing price is unique for the whole system.

On the contrary, if network constraints are considered and some of them are active at the optimal point, congestion can arise causing, along with losses, a different optimum, with a lower level of social surplus. In this situation a market clearing price no longer exists. Congestion may result in certain cases in market price volatility [16] and lead to price spikes.

The demand responsiveness can play a major role in competitive electricity markets, particularly in the case of congestion [6]. There are new degrees of freedom given by the introduction of load demand as an additional decision variable to be considered in the optimisation problem.

In the OPF security constraints are introduced as operational limitations on current flows in lines and transformers both in normal states (intact system) and in contingency cases consequent to the outage of single transmission equipment. The solution of the SCOPF is obtained by the use of an iterative quadratic programming algorithm [17] useful to handle very large scale systems as the Italian electric system, where a transition from a monopolistic structure to a competitive market is in act, passing through the unbundling and deregulation phases.

The actual organization based on a passing-through dispatch for the favorite bilateral contracts is going to be transformed in a hybrid structure (pool and bilateral) with ENEL Power, three major GENCOS, some NUGs, several IPPs and a single buyer. The acceptance of the generation offers will be based on a merit order list. The ISO, called in Italy GRTN (Gestore della Rete di Trasmissione Nazionale), will be responsible of the balance between generation and demand and of determining the optimal and feasible schedules. The SCOPF proposed in [5] for the solution of the ISO problem will provide, together with the loads and generation schedules, the marginal prices in the different busses: their volatility is consequent to the network congestion.

The price of the energy at a bus  $n$  is derived as the variation of the objective function consequent to an increase of 1 MW of real power demand in the bus. It can be evaluated as a linear combination of the Lagrange multipliers of the active constraints at the optimal point with the sensitivity of the right hand sides of the constraints (power flow equations and current limits) with respect to the real power demand in the bus. The prices of the energy at a given bus can be associated to the nodal marginal prices.

Simulations performed on a CIGRE 63 buses network demonstrate the adequacy of a two sided auction OPF tool to assist the ISO in determining congestion relief and in

controlling nodal price volatility. Some numerical results on a CIGRE test system are presented: the 63-bus network adopted (see figure 5) was previously used by the authors of [18] for applications of optimisation techniques to study power system

network performances in an open access environment. The test grid can be divided in five areas, named R, M, F, T, V. The busses of each area are labeled with an integer number with 3 figures, the area code and the voltage level.

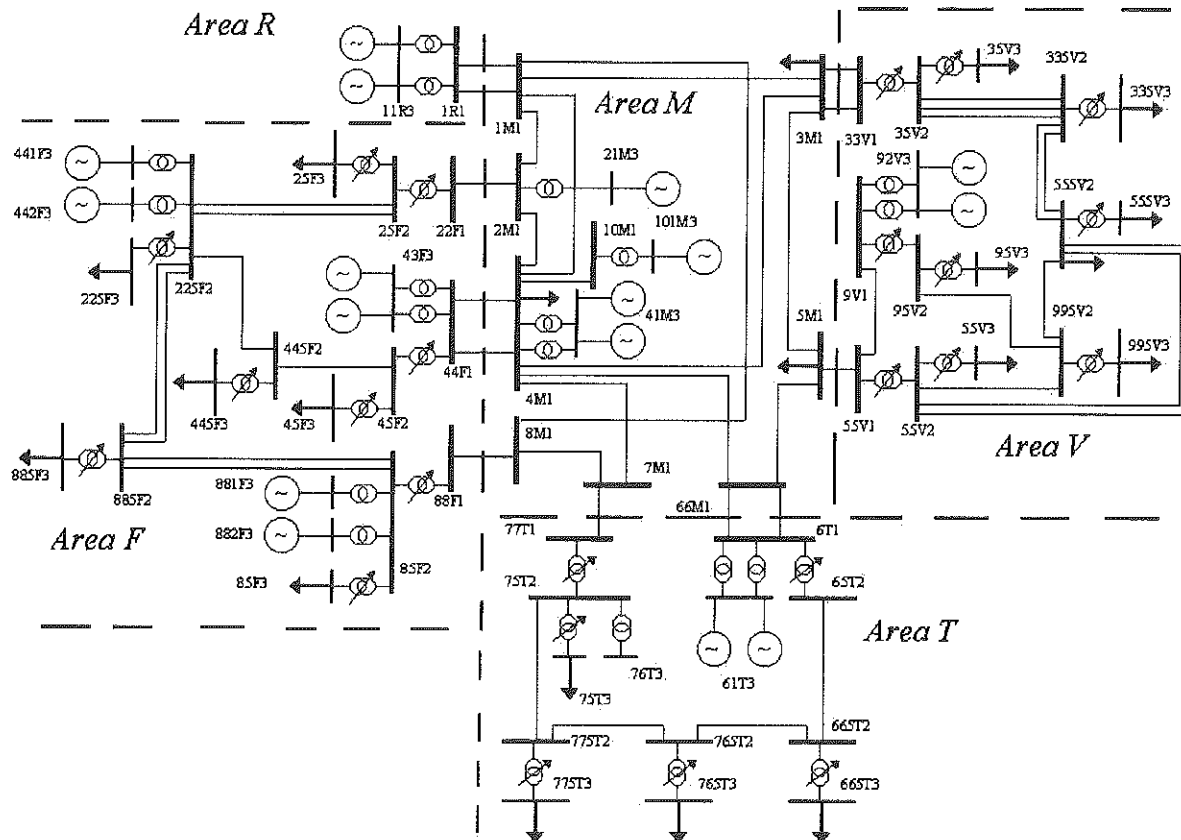


Fig. 5. The CIGRE 63-bus test system

As an example the busses 11R3, 65T2, 9V1 belong to the area R, T and V respectively and are referred to the voltage levels 15 kV, 150 kV, 220 kV. Area R represents an independent power producer, area M is the main grid at 220 kV, areas F, T, V can represent 3 sub-transmission systems at 150 kV with embedded generation. The prices of the generators in the areas R and F are very low, while prices offered in area V are very high. The bottleneck in the system is the line 1M1-3M1 available for the export of the least expensive generations of areas R and F to area V.

An unconstrained base case is given as the  $\beta$  dispatch solution. The dependence of the losses on the power injections in the network busses determines the distribution of nodal prices shown in figure 6.

The presence of network constraints in normal operation (N security) and in a single contingency constrained case (N-1 security) causes congestion on the line between busses 1M1 and 3M1. The congestion consequently leads to an increase of nodal prices in area V, as shown in figure 7 (for N security).

The effect of a two sided auction market structure on nodal price volatility is shown in figure 7.

In presence of the N-1 security constraints imposed by the contingency on the line 5M1-66M1, the line 1M1-3M1 is again the most important cause of congestion.

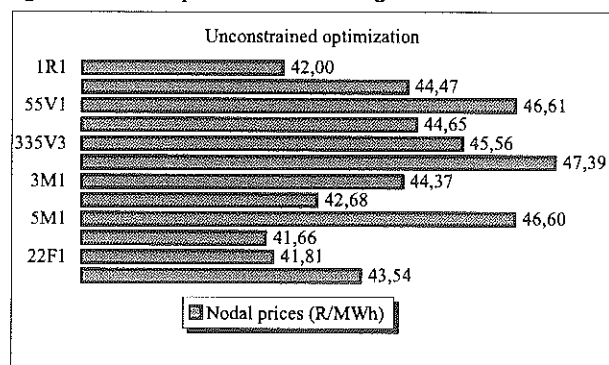


Fig. 6. Impact of losses on nodal prices

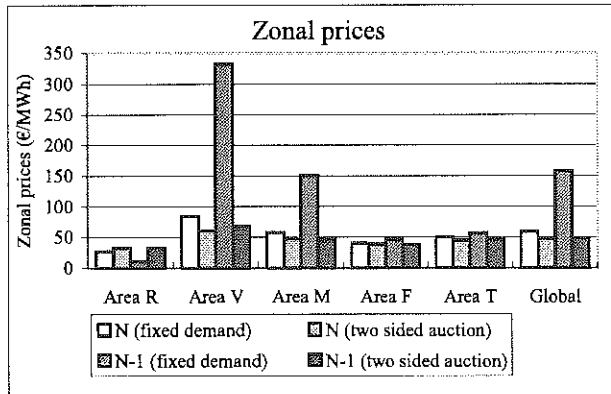


Fig. 7. Impact of congestion due to N security constraints

The zonal prices of each area, obtained as the weighted mean values of the nodal prices, are depicted in figure 8.

It is evident as if the power demand as no responsiveness to the electricity market prices, the volatility of nodal prices is extremely higher.

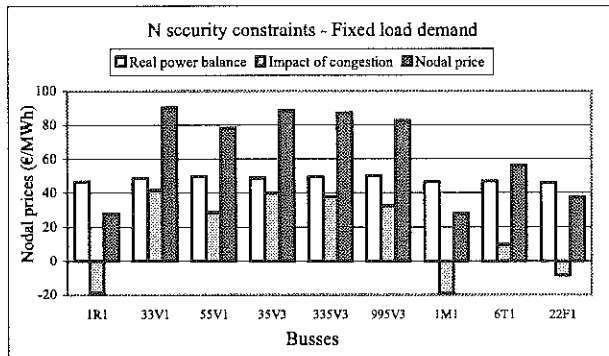


Fig. 8. Comparison of the zonal prices in studied cases

The results confirm that the demand responsiveness can play a major role in competitive electricity markets. In particular, in the congested cases the nodal price volatility can be used to send right signals in terms of load curtailability.

The new OPF can help the ISO, the PX and all the market investors, in terms of financial planning, operational planning and short term operation.

#### 4. FACTS devices as new control tools

In the application described in detail in [8], the need of operating the system in different load and generation scenarios has been investigated. The goal of increasing the network flexibility can be achieved by the introduction of some new devices: in particular, Flexible Alternate Current Transmission Systems (FACTS) [19] have been modeled. The presence of such devices on the grid (typically due to dynamic requirements) can be extremely useful for solving network congestion problems that may arise in an open access environment. The steady-state models of two FACTS devices (the Series Power Flow Control (SPFC) and the Thyristor

Controlled Phase Angle Regulator (TCPAR) [20] have been introduced.

The presence of FACTS devices results in new control variables (added to the traditional set of active power provided by generating units) that can be handled by ISO for a better operation of the system.

The system adopted for the tests is the same of figure 5; also the system characteristics are very similar to the tests presented in the above paragraph 3: the area M is a wheeling path for power exchange throughout the system, area M and F loads and generations are quite balanced, while areas V and T are characterized by large unbalances. Area R is supposed to be an IPP; the generators of area R and some generators of area F have been assumed very cheap, while the generators of area V are supposed to be the most expensive.

The cost curves of the generators belonging to different areas are given in [8]. A dispatch procedure based only on cost minimization ( $\beta$  dispatch with no security constraint, case A.0) leads to a heavy overload of the line 1-3 sending power from the cheapest IPP to the area V. Current flow on this line, which is generally a critical bottleneck for the system, reaches 1179A whith a rated capacity of 900A.

The distribution of the generated power among the five areas of the system in case A.0 is depicted in figure 9: this pattern was obtained neglecting system congestion.

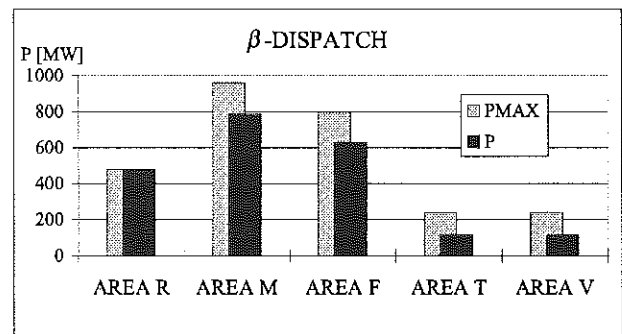


Fig. 9. Distribution of generated power among the five areas

Assuming case A.0 as a benchmark, new tests were performed.

*Case A.1.* For this first SCOPF test, a traditional economic dispatch without FACTS devices is used. The optimisation problem is subject to constraints on lines and transformers current flows in normal operation (no contingency is simulated).

*Case A.2.* An SPFC device ( $-20\%$  and  $+50\%$  of the line impedance) is introduced between busses 1 and 3; the optimisation problem is solved again with security constraints related only to the intact system.

*Case A.3.* The same problem of A2 is solved, with a TCPAR device on line 1-3; the limits of the related control variable are  $\pm 4^\circ$ .

*Case B.1.* In this case, the solution results from the economic dispatch without FACTS devices. The SCOPF problem is now subject to constraints on lines and transformers current flows in normal operation and in contingency cases. For the N-1 security simulations, the interface between areas M and V is considered (the tripping of line 5-66 is simulated, with a

significant overload on line 3-1). To find a feasible point of operation the possibility of accepting a temporary overload of the lines has to be considered; the relevant constraints are relaxed, by multiplying their upper bound (rated current value) by a suitable coefficient  $Cr$ . If only generators available as control variables, the feasibility of the optimisation is obtained with a value of  $Cr$  of 1.24.

**Case B.2, B.3.** Cases B.2 and B.3 optimisation problems are subject to the same constraints as case B.1 (normal operation and N-1 security). In case B.2 a SPFC device is installed on line 1-3; in case B.3 the same line is equipped with a TCPAR.

**Case C.2, C.3.** In cases C.2 and C.3 the same devices are installed: now, the coefficient  $Cr$  (N-1 current limit relaxation) is set at 1.19.

As can be seen in figure 10, in which only N-1 security tests are summarized, the adoption of new control variables allows a better distribution of power flows along the system, and, as a consequence, a lower value in the total production cost.

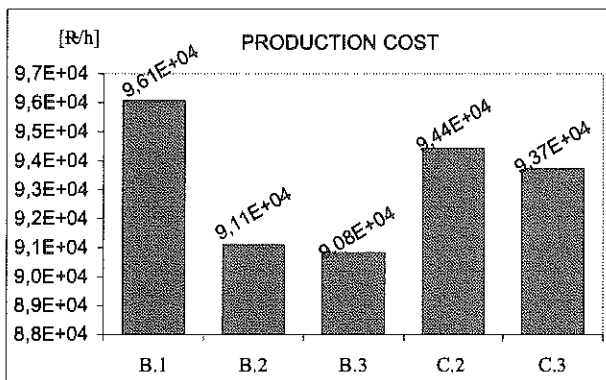


Fig. 10. Production cost in five test cases considered (N-1 security)

In case B.1, the possible trip of line 5-66 leads to an initial operating point with an overload of 42% in line 3-1 current. To relieve such overload, a significant generation shift is required: as a result, the current in branch 3-1 during the normal operation of the system is strongly reduced. The generation in area R is also lowered, while the expensive generators of area V are set at their upper limits, leading to a global production cost much higher than case A.1 ( $9.12E+04$  R/h).

In cases B.2 and B.3, the FACTS devices provide the opportunity to redirect the power flow through alternative paths; the N-1 current constraints have a lower impact on the system and, as a consequence, significant savings can be obtained. The values of the SPFC and TCPAR control variables in the optimal point are the same as in the corresponding N security cases (A.2 and A.3).

In cases C.2 and C.3 stronger current constraints are set; thus, the action of FACTS devices is more limited: this results in a production cost higher than cases B.2, B.3.

A detailed analysis of the Lagrange multipliers associated to active constraints in the optimal point shows the impact of FACTS devices on the energy marginal price at different busses of the power system. In the test cases studied with the above designed procedure, different constraints are likely to be active: real power balance equation and current constraints (for N and

(N-1) security) give partial contributions to the total marginal value at every bus.

Figure 11 shows the different contributions to the Marginal Cost (MC). MC is obtained by the summation of a number of terms equal to the number of constraints which are active in the optimal point. The term given by the balance constraint ( $MC_b$ ) assumes slightly different values for each bus; the contribution of active current constraint ( $MC_c$ ) (line 3-1) gives rise to significant differences among busses, as shown by the marginal costs in busses 1, 3 and 5 (directly affected by the current constraint), and in busses belonging to area V.

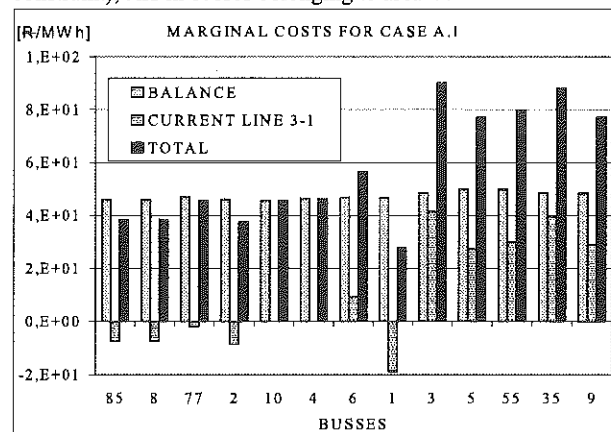


Fig. 11. Different contributions to marginal costs - case A.1

In the three cases presented in figure 12, different current constraints are active in the optimal point. In case B.1, the active constraints are the balance constraint (as in every case considered) and the N-1 current constraint on line 335-555 (area V). Due to the above contingency constraint, the constraint on line 3-1 is not active. In B.2 and B.3 cases the current constraint on line 3-1 is active. As the term  $MC_b$ , due to the balance constraints in the N-1 cases, is similar for all the busses, the total MC of busses 3 e 35 is directly affected by the two different active current constraints depicted above.

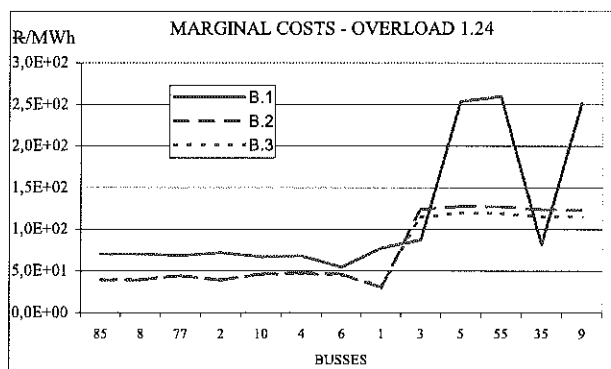


Fig. 12. (n-1) security tests marginal costs

As shown in figure 12, the  $MC_c$  term (due to the N-1 active current constraints) is quite different among the busses and results in a high variability of the total marginal cost of the busses which are more affected by the current constraint.

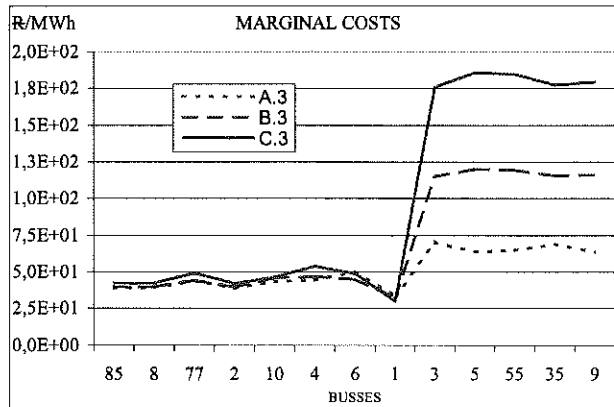


Fig. 13. Comparison of cases A.3, B.3, C.3 marginal costs

In cases A.3, B.3, C.3 (figure 13) the same system topology is considered (TCPAR installed on line 3-1), while the optimisation problem constraints change: in case A.3 only the N current constraints are set; in case B.3, the N-1 current constraint are added; finally, case C.3 is subject to N-1 current constraints more stringent than case B.3.

The current constraint on line 3-1 is active in all the three cases: in case A.3 it is active as for the N security; in cases B.3, C.3 the current constraint is related to the N-1 security. As the current constraints vary, the nodal prices of the buses which are not directly affected by the current constraint are quite similar. The MC of buses 3, 5 and of the buses in area V are more affected by those current constraints and grow as the constraints are added or become stronger. The variability of the total marginal costs becomes wider as much as the constraints affect more the procedure solution point.

From the point of view of the total generation cost, it can be noted that, when new current constraints are added (or the existing constraints are set to more restrictive values), the production cost increases (figure 9 and 10): this increase in the total cost can be seen as the “cost of security”. If the system is operated in a market environment, this additional cost becomes part of the uplift paid by market players in order to accomplish a suitable operation of the whole system.

## 5. Multi-objective Optimisation techniques

The application of new decision techniques to power system operation is presented in paper [11]. Among the possible choices (MO methodologies consist in: a) methods that first determine several possible working points, and then make the choice of the “best” operating point; b) methods that enable the decision maker to choose the “best point” in “one shot”[21][22]) the first set of methods has been considered, as they are more transparent and therefore well suitable to the electric market operation.

Moreover, the first set gives useful information that may help the ISO to understand the consequence of its decision on the market. These informations are related to the knowledge of the Pareto (also called non inferior solution) set.

A MO optimisation problem can be defined as follows:

$$\min [f_1(x), f_2(x), \dots, f_n(x)]$$

$$\text{subject to } g(x) \leq 0 \quad x \in X$$

where:

- $f_j(x)$  is the j-th objective function (OF) considered (to be minimised);
- $g(x)$  is the constraint vector (m elements);
- $x$  is the control variable vector (n elements) and  $X$  is the feasibility region.

A point  $x^*$  belongs to the PS set if, for any other  $x' \in X$ ,  $f_j(x^*) \leq f_j(x')$  for all j and, at least for one k,  $f_k(x^*) < f_k(x')$ .

The Pareto set can be not convex if  $X$  is not convex in the objective function space. After the PS is found, it is necessary to choose the final solution, using a criterion that can help the decision maker. The use of type a) or type b) methods depends on the features of the considered problem.

Type a) methods are more suitable when it is necessary to know as much as possible the consequences of a decision. In fact, they can provide the sensitivities of any OF with respect to remaining OFs, and this can give an idea of the robustness of the decision taken, in order to face possible perturbations.

Type b) methods are easier to solve, and need less computation time, but they can not give any information other than the final point.

The type a) methodologies apply better to power system analysis: once the Pareto set is calculated, the sensitivities of one objective function with respect to the remaining OFs are known. Therefore, the ISO has the best possible knowledge of the influence of any possible decision (control action), on objective functions that include technical, economic and security considerations.

The main methods used to determine the Pareto set are the Weight Method (WM) and the  $\epsilon$  – Constraint Method (CM). Their most important feature is the possibility of exploiting any implemented optimisation method to determine the Pareto set, therefore requiring only minor modifications to the existent traditional optimisation programs.

In [12] different methodologies to calculate the Pareto set are tested.

### 5.1. The Weight Method

A first method employed is named the Weight Method (WM). It transforms the MO optimisation problem into a traditional problem: the different OFs are weighted and added to form a single OF to be optimised. As a consequence, a traditional optimisation method program can be used to build the Pareto set.

The optimisation problem  $P(w)$  can be defined as follows:

$$\min \sum_{k=1}^p w_k \cdot f_k(x) \quad \text{subject to} \quad g(x) \leq 0 \quad x \in X$$

where  $w_k \geq 0$  and  $\sum w_k = 1$

It is worth noticing that the OFs are usually expressed in different units and the weights are used to compare them and to account for the relative importance of each OF.

The geometric interpretation of the WM is that, in the  $p$ -dimensional space of the OFs, the weights define an hyperplane, and the solution of each problem  $P(w)$  is represented by the intersection of the tangent plane defined by  $w$  and the Pareto surface. For this reason, it is possible to generate the entire Pareto set by means of the WM only if the OFs and the constraints are convex. Without the convexity, some noninferior solutions may not be discovered by the WM (whereas all solutions can be found by the CM): this fact is called *duality gap*. A point calculated with this method can not belong to the PS, therefore a test is available.

### 5.2 The $\epsilon$ -Constraint Method

The second method that can be used to build the Pareto set is the  $\epsilon$ -Constraint Method (CM). It allows to transform the MO problem into a traditional optimisation problem choosing an OF as the main OF and taking into account the presence of the other OFs as constraints in the main optimisation problem:

The main problem  $P_k(\epsilon)$  is defined as follows:

$$\begin{aligned} P_k(\epsilon) = \min f_k(x) \\ \text{subject to:} \quad & g(x) \leq 0 \quad x \in X \\ & f_j(x) \leq \epsilon_j \quad j=1, \dots, p \quad j \neq k \end{aligned}$$

where  $\epsilon = (\epsilon_1, \dots, \epsilon_k, \epsilon_{k+1}, \dots, \epsilon_p)^T$

The simplest way to draw the Pareto set by the WM is to vary systematically  $w$  and solve each optimisation problem  $P_k(w)$ . In this case, if any hypothesis is not satisfied, the test must be run (see [11] for more details).

The computational burden increases exponentially with the number of OFs and the number of the points desired for the PS. Problem  $P_k(\epsilon)$  can be solved by using any traditional optimisation method that associates a Lagrange multiplier to each active constraint. Its value is related to the variation of the main OF with respect to the active constraint, that is, in this case, with respect to the other OFs of the MO problem. Therefore, if  $\lambda_{kj}^*$  is the Lagrange multiplier associated to the  $j$ -th function when the  $k$ -th objective function is the main objective function, the following is valid:

$$\lambda_{kj}^* = - \frac{\partial f_k(x^*)}{\partial \epsilon_j}$$

The Lagrange multipliers are quite valuable for further analysis, because of their meaning as local trade-offs: this property is very useful for the decision maker to choose the final operating point from the non inferior solution set [13].

When the problem is convex, the sign of the Lagrange multipliers can also be used to verify if the considered point is in the Pareto set: a solution  $x^*$  belongs to the PS if all the Lagrange multipliers associated to the secondary OFs are strictly positive. In these cases, further tests are not necessary.

The CM is usually more intuitive than the WM. Moreover, it allows the determination of the entire PS in any case (even when the Pareto set is not convex, as for the WM), given that significant values of the component of  $\epsilon$  are available. These last values are easier to assign than the weights in the WM, as they are more strictly related to the power system physics. In fact, the ISO can define them based on its knowledge (e.g. by historical data) and on the goals to attain. In the short time horizon, many different objective functions can be considered by the ISO [23]. In particular, the objective functions related to the security of the electrical system play a central role: ISO can change the economic dispatch (given by the market) only if security problems arise [24]. For these reasons, the MO optimisation technique can help the ISO to understand the consequence of its decision on the market. The MO problem gives non unique solutions, but if ISO adopts some specific decision criteria, MO can be a useful tool to guarantee the independence and the transparency of its decisions.

### 5.3 Test and results for Security, Real power reserve Cost and Area Import

This case allows to define the relationships between Security (VI), represented by a voltage collapse index  $\sigma_{\max}$  (the maximum singular value of the inverted power flow Jacobian), the Real power reserve Cost (RC) and the Area V Import (AI) (see [11] for the data) for the 63 buses CIGRE test grid. The shape of the Pareto set in the space of the OFs is depicted in figure 14.

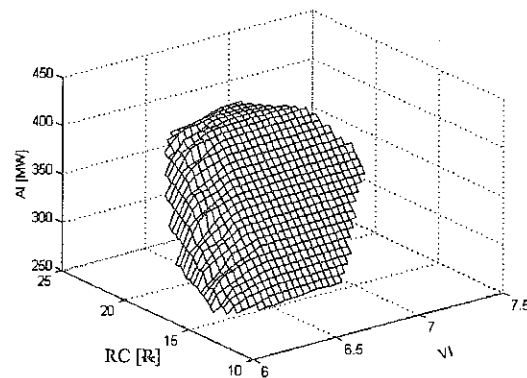


Fig. 14. Pareto set for VI, RC and AI

For this test, the RC of generators in Area V is set higher than the other RC costs. For this reason, as the AI increases, the RC

increases too, as the generators of Area V are less loaded. On the other hand, increasing AI results in worsening of VI, because it leads to higher current values in the interconnections between Area V and the remaining part of the system. Moreover, in this case, due to the differences in the generator reserve costs along the system, VI and RC are conflicting objectives, once the AI is fixed: the attempt to lower RC gives an operating point closer to the voltage collapse. This information is provided by the Lagrange multipliers or the weights (in the CM and WM respectively). When ISO has calculated the Pareto set, many informations about the influence of each OF on the remaining OFs are available. One of the most important informations is the local trade-off among the OFs: using this information it is possible to choose the final solution with an interaction process with the ISO. Other different techniques that allow to choose "automatically" the final solution form the Pareto set are available [13], but, in general, it is necessary an interaction procedure with the decision maker (ISO) to consider his point of view of the problem: the final solution depends on the criteria used and on the relative importance. Therefore, the ISO has to define the criteria and the weights to choose the final point. If such rules are known to all market participants, the procedure to obtain the solution is transparent.

The MO methodologies can give a better knowledge of the system and are useful tool to understand the consequence of the security requirement on the energy market. They can help the ISO to define its behavior when some security problem are present on the system, and, if the criteria of choice are defined *a priori*, a transparent decision is guaranteed.

## 6. Conclusions

The paper analysed the evolution of the policies adopted both in planning and operation of power systems in consequence of the liberalisation of electric energy markets. Some possible suggestions are given about the restructuring of the objectives to be pursued in the optimisation programs and about the constraints related to the maintenance of the quality and security performances at levels comparable with the past.

A first application focussed on the correct management of all the transactions, by adding new terms to the objective function of a traditional OPF. Furthermore, the impact of new control tools (i.e. FACTS devices or correct economical signals related to nodal prices) has been investigated.

The tests highlight that transmission will still have a crucial role in the new market environment: the related constraints (managed in a corrective or preventive way, depending on their effect on the final energy price), force the ISO to find a trade-off between security and economic requirements.

As the above technical and economic duties may give rise to mutual conflict, the use of Multiobjective Optimisation (MO) techniques is envisaged: such techniques may provide the ISO a tool useful to adopt proper decisions when security problems are present in the system, by providing significant indications on the consequences of any possible choice with respect to all the objective functions considered.

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## Discussions on Session VI: VOLTAGE SECURITY ASSESSMENT & STATIC SECURITY ASSESSMENT

### Part 2

**Chairman:** About the final presentation, you're saying that you're scheduling, or your company is scheduling the FACTS device. As I see in any application, that is a static application actually. So I would like to do if the FACTS device is used for the dynamic stability purposes or the static stability purposes. If it is only for the static purposes, I think you could use some mechanically switched controller as well.

**M. Delfanti:** The company is GRTN, which is the national ISO in Italy. They plan to put it into service. They said some FACTS device, because one of the problems of Italian market is lack of transmission capacity at the borders. As you may know, in France and Switzerland, energy is cheaper, as my colleague at EDF will know. The problem is to send the power to Italian loads. So as I noted in the paper, maybe FACTS typically are used for dynamic purpose. But in our simulation, we just want to show that, given the cost of the device, and given the improvement in the ATC at the borders, just based on static affect. It is worthwhile to put in service such a device. Of course, we would be positive after months in terms of dynamic stability and so on. But in our paper, and you'd find it in paper, we just did it with problems of a static mode.

**I. Hiskens (University of Illinois):** Just following up on that subject of FACTS devices. What would be a procedure, I guess, for determining this location, say you would like to build two FACTS devices, could you use your optimal power flow for determining what way is the best thing?

**M. Delfanti:** In our case, you should apply a heuristic procedure, so just try to put them up, and see if it works. But we're working on something based on genetic algorithm, and the best side thing of this device. But based on the experience, so people like GRTN, the Italian ISO, it is very well known, which are the systems affected by congestion. I think it's quite sure, which is the optimal placement of those devices. In a real system, we did the test system as we did. You can take advantage of some genetic algorithm to choose the best placement. But it becomes quite a huge problem, because of the strong non-linearity and unbounded variables. So this is catered to apply to a real system.

**C. Canizares (University of Waterloo):** I guess on the issue of FACTS, the Italian system once has been considered phase shifters, there is no issue of dynamic control or any kind. So that is not a concern, and I

guess that's what you said in your paper. I'm trying to understand what you mean within N-1 security in your optimization, is it just the limit you put in the transmission lines?

**M. Delfanti:** When we ran N-1 security, it means we consider of course one 3, the rated current of the remaining lines, maybe the same as the normal operation, or maybe elastic. So maybe, let's say, one point two times greater than the normal operation.

**C. Canizares:** So you're simulating contingency?

**M. Delfanti:** Yes. In preventive case, it is just contingency and reactive power flow with no change in the generation. On the other side, we have a N-1 criterion, so we're allowed to change the generation, and we also take into account of dynamic constraints and loads.

**T. Overbye (University of Illinois):** One of the interesting aspects of deregulation is as we add the new devices to the system, like FACTS device, you know there are winners and there are losers. I saw in your slides that the locational marginal prices changed. If you're a consumer, that's good. But if you're a supplier in that area, that's not good. Then on the other side of the constraint, because now you can get rid of your exports more, the locational marginal prices went up. It's not really a question. But with deregulation, how do we sell this to people in that we're adding new places that for some people they are going to be worse to make this system more expensive?

**M. Delfanti:** May be I can explain it to you that Italian market is really not a market, or maybe not yet a market. So as far as now we Italian ISO, they're supposed to have a system with national benefit. So no one is arguing about which location for FACTS devices, because our problem is just to improve the capability mainly with Switzerland and France, which is the same thing, because much of the power coming from Switzerland really comes from French units. So this is the issue now. We do not have yet this problem of considering who has to pay, who gets benefit, it's not yet the time to consider this.

**C. Vournas (NTUA):** I have a question for Professor Menniti, although it was partly answered by the last presentation. I like the way that you in your formulation use a balance between some load curtailment and

some generator re-scheduling, which is also related to the question by Tom Overbye. I think that in the new environment, you're really not doing the optimization, unless you specify for whose benefit you're doing it. So I would suggest that if you model at least part of the so-called up-lift cost for security, then it would be easier to find the way in the new environment to implement this type of control, which I think would be beneficial for everybody.

**D. Menniti:** Yes, I know the problem is to choose who will gain in this case but our work doesn't count on this problem but just this is a final step. The broker has to choose the previous dispatching and then all the inclusion from the economic point of view we have chosen.

**T. Overbye:** This is a kind of follow up on what C. Vournas said. I guess it is directed to all of you. As you go through these algorithms, you know there is a rather complicated algorithm, there is a lot of assumptions built into them, and this is going to be this case. You know the ISO is going to run this algorithm to determine prices with a lot of assumptions. A problem that arises is that the market players, in most markets don't have the ability to go in and audit what's going on. They are impacted by all these hidden assumptions, but they don't get to see them. The decision like adding a new line, probability of contingency, is just all the parameters went into your models that determine ultimately how much capacity there is, what price unveil as a market player. I'm a little concerned that the market participants are not getting the reproduces. Nobody is really looking over the shoulder of the ISO. So just comments on that. What should we do? How should we address this problem?

**M. Delfanti:** Our system relies very much on FACTS operation by ISO. But they stated that in some cases the OPF would be run. As far as now, no one in the market participants have any comments about this. Maybe that the first time it happens, the tie-load of megawatts generates some money, then there will be some different views on this problem. But as far as now, what ISO is doing is looking for some tools, analytical tools, would be more simplified than these of course, because I think some are complicated. But they're just looking for tools like this to say how to really dispatch the power in case of congestion. But as far as now, the Italian system was planned 20 years before, and thinking of a revolution of load just not in the place really. So now we have neglected the problems at the borders, just talking about inside the Italian system.

**C. Vournas:** Just to rephrase my previous comments addressed to the two papers from Italy. I think that in the present market structure in Europe, what is done in most market is that you have unconstrained dispatch first, and if there is some security problems, the ISO is

able to re-dispatch, or even curtail the load, maybe, if this is allowed by some contract. The cost of this action, whether rescheduling or load curtailment is called up-lift cost, and is going into the price of kilowatt hour. In the European context of solution, the OPF price, which is maybe a more exact method, is not directly applicable. What could be applicable is an optimization that minimizes the up-lift cost, and everybody would be very happy with this, which is essentially the same as solving the optimization problem with a different method.

**M. Delfanti:** It's an OPF. Someone thinks that it would be to impose minimal shift on the power of generators and someone has to admit to impose a minimal cost, which is slightly different. It's not exactly the same. Of course this cost will be part of the operation, which will be given by scheduling, but anyway, technically they should run an optimization program.

**C. Vournas:** This is exactly what I'm saying. It's an optimization problem to minimize the up-lift cost, and not to schedule nodal prices. The way you have modeled the elasticity of load, maybe is not applicable in the present European market. This was my comment.

**Chairman:** Thank you for the patience. Let's thank the speakers.

**Session VII:**  
**CONTROL**

Thursday, August 30, 09:00–12:30

Chair: Chen-Ching Liu

# Global Hybrid Control of Power Systems

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## Abstract—

This paper presents an overview of recent results on an approach to total control of power systems. It is upwards compatible from any conventional or prior advanced control and provides a framework for coordinated development of control to address all major dynamical problems. The ideas will be illustrated by consideration of coordinated control for transient stability, voltage regulation and emergency voltage control.

## I. Introduction

This paper describes progress towards a general methodology for control of complex systems, particularly those that have large scale, are strongly not linear and have substantial uncertainty in their modeling. The work is motivated by earlier work, on transient stabilisation and network control for voltage security of power systems, and same ideas for general control [1–6]. In arriving at progressively more general and flexible approaches, various techniques from advanced modern control have been absorbed such as dynamic programming, model predictive control, nonlinear control, so-called fuzzy control (just a non-linear control formula), switching and hybrid control. The overall aim to devise controllers which deal with complexity is called global control.

Models are assumed to be of a heterogeneous hybrid kind, ie a mixture of differential, algebraic and switching equations with different versions in different spatial and state domains. The various control elements correspond to existing physical controls, typically designed independently and assumed to be tunable, and other modules to be designed. Control is implemented in several layers of continuous and discrete actions.

Under pressure to expand the capability of the system, such as occurs for power systems under the influence of deregulation, the concept of control-based expansion becomes compelling [16]. This idea suggests that advanced control

can effectively replace physical system expansion. Thus planners could delay building of new network expansion or even allow the decommissioning of controversial constructions.

Global hybrid control is presented as natural way to harness all the control elements optimally to coordinate a control response to dynamical problems as they arise. The controlled response can be designed to achieve feasible secondary specifications such as for transient behavior, quality of supply, economy. Global control is a relatively new concept which has evolved from techniques like gain scheduling and more recent multi-model control. The key idea of global control is to combine the qualitative and quantitative knowledge through some hierarchy (see [7]). One of the most practically successful approaches for utilizing the qualitative knowledge of a system to design a controller is fuzzy control. Results have been obtained in [8] where heterogeneous control provides combination of local control actions appropriate to different operating regions. A common feature of these methods is that they make use of mature results for the local controller design and provide necessary coordinations. The main feature allowed here is that the local controls are coordinated in optimal control schedules.

Following development of the main ideas, two important problems in power system control will be used for illustration, namely transient stability control and network control.

Transient stability and voltage regulation are both important properties of power system control, but they are ascribed to different model descriptions and relate to different stages of system operation (i.e. transient period and post-transient period respectively). Earlier control results deal with the two problems separately, or employ a switching strategy of two different kinds of controllers, which causes a discontinuity of system behavior. We design in this paper a global controller to co-ordinate the transient stabilizer and voltage regulator. The designed controller is smooth and robust with respect to different transient faults.

To enhance the transient stability of power systems, in

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recent years a great deal of attention has been paid to the application of feedback linearization approaches [9], see e.g. [10–12]. Compared with use of conventional approximate linearization, which can only deal with local stability around an operating point, the controlled system can endure large disturbances and retain a steady post-fault condition. Inevitably, in order to enhance the stability, the power angle has to be one of the feedback variables whereas the generator voltage is not needed. In such transient stabilizing control, a common phenomenon is that the post-fault voltage value varies considerably from the prefault one ([13]). From the practical point of view, voltage quality is a very important index of power supply in power system operation; so the post-fault value is expected to reach the normal value as closely as possible. In [13–15], voltage regulation was achieved by introducing voltage feedback. However, the voltage controllers are only effective around a working region, i.e., they work well when a small disturbance occurs and at the post-fault stage, but cannot survive a large disturbance.

Different behavior of nonlinear power systems in different operating regions requires different control objectives and consequently different control actions must be employed under varying operating region. How to achieve a satisfactory control performance over a wide range of anticipated operating conditions is demonstrated using global control.

The second major illustration introduces use of optimal control to achieve coordination of local physically based controllers. A method of optimal coordination is presented for load shedding, capacitor switching and tap changer operation using a dynamic system model in order to preserve or retain long-term voltage stability. The method is based on model predictive control and a tree search. A model of the controlled system, including the network and load dynamics, is used to predict the future system behaviour based on the current state and applied control actions. The optimal control state according to these predictions is then obtained using a search method similar to those used in chess computers.

The structure of the paper is as follows. Section II will discuss global control in general terms. Section III and IV present the specific illustrations of transient stabilisation with voltage regulation and network control with dissimilar devices respectively. Section V gives some conclusions.

## II. Global Control Ideas

### A. Introduction

Global control is a further development of modern control towards the capability to handle complex systems. Like power systems, many practical systems have the following four major characteristics: 1) substantial nonlinearity; 2) large-scale; 3) variable uncertainty in the model; and 4)

hybrid or heterogeneous form. The last aspect refers to a mixture of control actions, ie discrete and continuous, and control requirements, possibly in different regions of operation. Adaptive, robust, intelligent and stochastic control are well-known methodologies which overcome parametric variation, unstructured uncertainty, unknown models and random disturbances respectively. Here it is of interest to note more recent developments in so-called multi-model, switching and hybrid control [19] [20] [21] [22] [23] as at least partially able to address the problems of complexity in a holistic way. No attempt is made to give extensive references; some representative results directly supporting this discussion only are chosen for reference. It remains to develop these methods to address systems of serious large-scale and mixed uncertainty types such as appear in power systems. In practice, a framework is needed for designing controls of a truly global kind which act in a coordinated way across the whole system geographically and for all operating situations, ie for all states and in-the-large (in the sense of stability theory) as parameters and conditions vary. This appears possible by combining ideas already developed for power systems with some of the newer techniques in control.

There are several desirable features of complex systems which apply in the case of power systems: 1) the system has a large-scale network structure; 2) many of the controls are embedded in the system with some having scope for tuning; further control design must allow for and enlist where possible these existing controls; 3) the overall control scheme will have a hierarchical structure; 4) the control actions available physically are already largely determined and have diverse timing, cost and priority for action; 5) the control goals are multi-objective with local and global requirements which vary with system operating state, eg normal and insecure states in power systems; 6) the control interacts with the planning of the system, ie. better control expands the system capability and effectively reduces the need for physical expansion. Of course, many systems in industry, such as chemical processes, shares these features. A related issue which is often mentioned in more practical discussions of general control science needs is "re-configurability". It is recognised that the control designers have a huge toolbox of techniques for developing the models and local controllers throughout a system. There needs to be more effort on the higher levels of control to deal with failures and external events. Power systems engineers certainly need no reminding of this issue.

In general, we need a high-level version of distributed adaptive optimal control which "swarms" around the complex system attacking problems as they arise, but keeping a meta-view so that other problems are not ignored while attending to a particular one. Needless to say the implementation requires accounting for physical features like physical sparseness and time-scales as always to reduce computation demands.

### B. Hybrid Models

The use of hybrid models in power systems is already well-accepted to capture the use of mixed continuous and discrete control actions [69]. The equations often take a differential-algebraic-difference (DAD) form as follows

$$\dot{x} = f(x, w, z(k); \lambda) \quad (1)$$

$$0 = g(x, w, z(k); \lambda) \quad (2)$$

$$z(k+1) = h(x, w, z(k); \lambda) \quad (3)$$

The dynamic state variables  $x$  are variables that appear as derivatives in the differential equations and cannot change instantaneously. On the other hand, the algebraic state variables  $w$  do not appear as derivatives, and can thus change instantaneously due to changes in  $x$  or  $z(k)$ . The discrete state variables  $z(k)$  have discrete-time dynamics and can change only at fixed time instants given by a selected sample time. The dynamic state variables relate to generator flux, control and load dynamics; algebraic state variables relate to network voltages and currents, and the discrete states  $z(k)$  typically arise from discrete control logic such as relay controls. The parameters are denoted  $\lambda$  and may include control parameters, independent parameters and action variables. We can write  $\lambda = (\theta, \vartheta, u)$  where  $\theta$  represents tunable parameters,  $\vartheta$  represents the (structured) uncertainty and  $u$  the control variables which are yet to be designed. The basic DAD model will include and control algorithms (discrete and continuous) for which no further tuning is planned.

terms for power systems in [24] [25]. In particular, the discrete time actions can be generalised to allow for switching and reset events which depend on system behaviour. Recent advances in modelling software make use of such models more straightforward. For instance, we can use the modelling and simulation tool Dymola, which has a power systems library [26].

As for differential equation models and DA models, eg. see [27], a basic set of analysis tools for DAD systems is needed. This is currently the subject of active research. Some results have been summarised in [29] [28].

### C. Control Elements

One of the problems with applying modern control methods like adaptive, fuzzy or robust control to power systems is that they are established in a generic framework which is not sensitive to the structure of particular practical systems. Hence many practitioners get the impression that these methods, while sounding appealing at first, are really intellectual games. A more specific challenge is to blend these new ideas into the overall scheme of control which exists, ie excitation control, PSS, network regulators, eg tap-changers, security control. Typically, much of this is already trusted and we only need some new control modules and some overall co-ordination.

Co-ordination has not been a strong point of power system control in the past. Generally a sequential design approach has been taken rather than a holistic (or global) approach. It has often been the case that the solution to the last problem has caused the next problem, eg fast excitation systems for transient stability led to self-excited oscillations. Of course there were limitations in control technology which prevented use of a more comprehensive approach and the ingenuity of engineers to overcome these problems has been impressive. It might be thought that this has about met its limit with recent changes in the industry - see later. However, modern information technology for control, communication and computing (CCC) gives us possibilities to use intelligent distributed algorithms to complement more traditional approaches. It is worth noting that many of these issues have been dealt with in a simpler form in development of coordinated PSS schemes in the 1980's [30] [31] [32]. The PSS modules were designed largely according to local stability criteria. They could be designed sequentially or simultaneously to accommodate the effect of interactions, but this could be a large computational task either way. The simultaneous approach amounts to an optimisation of any tunable parameters within certain operating constraints to position the closed loop modes of the system with adequate damping. In Russia such algorithms were highly developed for co-ordinating stability on large systems and robustly with respect to changes of system structure - see [33] and especially the references within. In this particular problem, it is interesting to note that system structural conditions were found, related inter alia to loading levels, under which the designs could be largely decoupled [34]. Typically, such decoupling does not apply in heavily loaded systems, but its presence in any degree maybe useful.

In looking to generalise these ideas to the whole control problem of maintaining stability while providing specified performance, we start by identifying the basic *control elements*, ie those existing controllers and their tunable parameters which are free to adjust for system-wide purposes. These will be based on physical devices or at least the designs for them. The controller could have the form

$$u_i = U_i(x_i, w_i, z_i(k); \theta_i, \vartheta_i) \quad (4)$$

where subscript  $i$  refers to a geographical part of the system or some special control task, eg. transient stabilisation in power systems. The controller is typically expressed as a function of state variables or as a dynamical system driven by certain system outputs. This controller could be anything from a simple classical PID controller to the most sophisticated nonlinear controller (including rule-based, fuzzy or model-based designs such as feedback linearisation). The controller is required to perform well in spite of the uncertainty  $\vartheta_i$ . The parameters  $\theta_i$  are available to implement co-ordination with other controllers.

#### D. Bifurcations and Global Control

The development of nonlinear control theory has generally evolved along several lines of thought. There are many books on this topic - see for instance the recent ones [9] [35] [36] [37]. Emerging from mathematics of dynamical systems and the study of some specific systems, there has been an extensive study of nonlinear systems dynamics in terms of underlying bifurcations in the models [36]. This line has been extensively pursued for power systems analysis [38]. While bifurcation control has been developed for special systems of scientific interest [39], it has not been developed for power systems in any practical way. Most work on generic nonlinear control, eg [9] [35] [37], does not deal with the bifurcation structure. In fact, many assumptions used in the development of nonlinear control algorithms effectively rule out bifurcations of dynamical behaviour. When we consider the possibility of parameters crossing boundaries, we should develop control on at least two levels, as is commonly discussed for power systems: the first level uses continuous and switching type control to establish an appropriate equilibrium operating point (or manifold); the second level deals with the system dynamics around these operating points and uses techniques from stabilisation and local bifurcation control. We could classify controllers as: 1) bifurcation avoiding; 2) bifurcation delaying; 3) bifurcation eliminating; 4) bifurcation accepting. Loosely speaking, the controller could keep the system well away from the bifurcation boundaries, as is typical for power systems, push the boundaries further away in parameter space, eliminate certain boundaries, or devise a scheme for operating across the boundaries. The study of performance of the various forms of textbook control tools in these situations is incomplete, but intuitively they will have many problems in their basic form.

Our global control objective is to achieve good control performance over a wide range for the anticipated operating region with robustness to different faults whose sequences are not known apriori. The bifurcation boundaries define domains of operation where the dynamical behaviour is qualitatively different, see [38] for review papers. A possible control strategy, accepting the boundaries, is to design controllers for each structurally stable region and switch between them in some way. A scheme which has the above-mentioned two-level structure has been presented and used for a standard example in [5]. The switching controller has a weighted Sugeno type form used in fuzzy control, but is motivated by the need to allocate control effort according to dynamical behaviour. Assuming the state-parameter space is partitioned into two domains, the control  $u$  takes the form:

$$u = u_e + \mu_1 v_1 + \mu_2 v_2 \quad (5)$$

where  $u_e$  provides the new equilibrium manifold;  $\mu_1$  and  $\mu_2$  are functions of an indicator variable expressing the closeness to a particular region or control concern; and  $v_1$  and  $v_2$  are the local controllers. The overall control for a specific design is just a special form of nonlinear controller which

can have the general form 4, ie it may have tunable parameters. There may be many such controllers acting on the complex system.

More generally the domain boundaries could be defined by regions where modelling is unknown and typically behaviour changes in some major way, so switching control again becomes natural. Between these discrete models the models are incomplete and uncertainty must be allowed for. A complete model becomes an interpolation which can be expressed in various ways, eg see [8] [40] for use again of fuzzy-control type membership functions.

#### E. Optimal Coordination and Swarming

Once all the local controllers are all designed, the freedom to use them flexibly should be fully exploited. It is of no great concern that the controllers might be complex in themselves. Besides the argument that they can often be expressed in software code, at a system-wide level the controller complexity is related more to the number of parameters that need tuning. This may involve simply tuning of free parameters, as in the PSS case mentioned above, or a more complicated scheduling exercise which allows for any control redundancy to use scaling and timing according to control costs, dynamic properties and priority. The latter idea is familiar at least for static scheduling in operations research, but is quite complicated for dynamical systems as it requires the solution of the optimal control problem [41] [42]. A technique along these lines has been developed for optimally coordinated voltage security control of power systems [1] [3] using differential dynamic programming (DDP) and trajectory sensitivity methods to set-up the staged use of available controls in an optimal way. However, there is a wealth of techniques which can be explored here. Many ideas in modern control boil down to use of optimal control. In Section IV, we will illustrate further work on the voltage security problem using Model Predictive Control (MPC) and search techniques as a way to set up the optimal tuning. The connection between DP and MPC can be made [43], but each has been developed with a set of techniques for implementation with various forms of complexity. There are many special ideas which can be mentioned to implement optimal coordination. One useful one, which suits the current framework, was formulated in the Russian literature and used for adaptive nonlinear control [44] [45]. The control objective is expressed in memoryless or integral form. The control algorithm takes a two-level form of a controller of the form 4 and a so-called speed-gradient parameter update.

The switching idea expressed above can be interpreted as allowing the controller to adjust the individual contributions of the local controllers according to the particular problem being faced at a given time. For instance when an instability occurs in a certain domain or in a certain variable type, eg voltage instability, the indicators driving the weighting functions will automatically adjust the con-

trol to emphasise the appropriate actions. When optimal coordination of many such controllers is considered, we can think of numerous controller elements in a complex system as swarming [46] to deal with problems as they arise.

It is beyond the scope of this paper, but it is easy to see all special forms of adaptive and learning control as specific examples of a coordinated tuning of control elements framework. The theory of aspects of optimal control for structured nonlinear systems with variable parameters needs further development, but many ideas have already been established in the development of adaptive control-see for instance [47] [19] [48].

#### F. Issues for Practical Implementation

There has been a lot of discussion about to what extent new control ideas are needed for power systems in the era of deregulation including at the previous IREP Conference [49] [50]. To some extent, the trend has been happening anyway towards operation closer to stability (or bifurcation) boundaries and in situations away from which planning was done, ie. more nonlinearity, and greater interconnection, ie. larger scale. With deregulation comes the possibility of less easy availability of data for modelling, ie more uncertainty, less centralised and more diverse control, stricter quality of supply requirements, nondiscriminatory access, all of which make the control task more difficult. One way or another power systems are becoming more complex and so vulnerable to unexpected phenomena. The above discussion can be interpreted as an expression of confidence that we have the tools to meet whatever challenges arise. Further, the use of these tools in the framework discussed here is entirely compatible with continued use of existing and trusted methods, ie there is upwards compatibility from lower level controls.

The practical implementation of global control ideas draws upon numerical algorithms for analysing DAD systems, prediction, and optimisation. The "curse of dimensionality" is familiar and has been overcome in many other areas of engineering. In power systems, there is a lot of structure in the network giving sparseness and several time-scales; as in other areas like power flow and stability analysis, this should be exploited as much as possible in achieving computational savings.

### III. Global Transient Stability and Voltage Regulation

#### A. Introduction

In this section, we design global control to maintain the transient stability and achieve satisfactory post-fault voltage level of a power system when subjected to a severe disturbance. The control signal from the global controller

is the average of the signals from the local control laws, each weighted by the value of its operating region membership function. Since the membership function can be determined by direct measurable variables of power systems, it has several appealing properties compared with the switching control strategy proposed by [13]. For example, to achieve control action switching, the fault sequence needs to be known apriori; also as long as the switching time is fixed according to a certain fault, the system may not survive another different fault. The global control law overcomes these disadvantages by sensing the relevance of stabilisation and regulation and automatically shifting to the appropriate controller. By a smooth transition between pure control regions, our global control objective is achieved. It is important that it adopts a mature control strategy in each local region, i.e. familiar schemes can be preserved.

The results presented here are based on the paper [6].

#### B. Dynamical Model of Power Systems

We consider the particular SMIB power system arrangement shown in Figure 1. The actual dynamic response of a synchronous generator in a practical power system when a fault occurs is very complicated including many nonlinearities such as the magnetic saturation. However, the classical third order dynamic generator model has been commonly used for designing the excitation controller. More complete models are used in the simulations to evaluate the design in the presence of other effects.

The classical third-order dynamical model of a SMIB power system (Figure 1) can be written as follows ([51–53]):

*Mechanical equations:*

$$\dot{\delta} = \omega \quad (6)$$

$$\dot{\omega} = -\frac{D}{2H}\omega + \frac{\omega_0}{2H}(P_m - P_e) \quad (7)$$

*Generator electrical dynamics:*

$$\dot{E}'_q = \frac{1}{T'_{do}}(E_f - E_q) \quad (8)$$

*Electrical equations:*

$$E_q = \frac{x_{ds}}{x'_d}E'_q - \frac{x_d - x'_d}{x'_d}V_s \cos \delta \quad (9)$$

$$P_e = \frac{V_s E_q}{x_{ds}} \sin \delta \quad (10)$$

$$I_q = \frac{V_s}{x_{ds}} \sin \delta = \frac{P_e}{x_{ad} I_f} \quad (11)$$

$$Q_e = \frac{V_s}{x_{ds}} E_q \cos \delta - \frac{V_s^2}{x_{ds}} \quad (12)$$

$$E_q = x_{ad} I_f \quad (13)$$



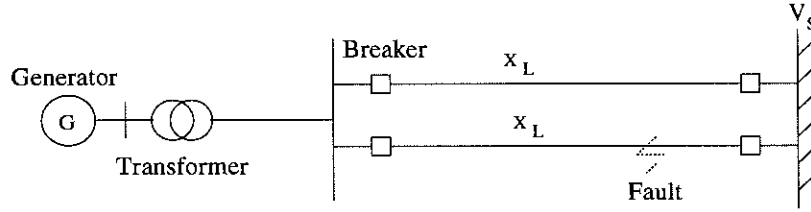


Fig. 1. A single machine infinite bus power system

$$E_f = k_c u_f \quad (14)$$

$$V_t = \frac{1}{x_{ds}} [x_s^2 E_q^2 + V_s^2 x_d^2 + 2x_s x_d x_{ds} P_e \cot \delta]^{\frac{1}{2}} \quad (15)$$

where  $\delta(t)$  is the power angle of the generator (in *radian*),  $\omega(t)$  is the relative speed (in *rad/s*),  $P_m$  is the mechanical input power (in *p.u.*),  $P_e$  is the active power delivered to bus (in *p.u.*),  $E_q'$  is the transient EMF in the quadrature axis (in *p.u.*), and  $V_t$  is the terminal voltage of the generator (in *p.u.*). The notation for other variables and parameters are standard and readers are referred to [13, 53, 54].

The fault considered in this paper is a symmetrical three phase short circuit fault which occurs on one of the transmission lines.

In the next section, we test the existing controller performances on different fault sequences, and then in Section 3.D a new global controller will be presented and tested.

### C. Local Controllers

#### C.1 Nonlinear Controller for Transient Stability

As discussed in [9], feedback linearization is a quite appealing design method for nonlinear systems. Since it avoids the local nature of approximate linearization and transforms the system to be linear over a very wide range, it has been applied to power systems by different authors shortly after it was available – see e.g. [10–14, 55–58]. In the following, we briefly describe the design based on so-called direct feedback linearization (DFL) compensators [12, 13]. This preserve more easily allows actions of physical states than the geometric algorithm version in [9].

By a DFL transformation ([12]), (6)–(8) becomes

$$\begin{aligned} \dot{\delta} &= \omega \\ \dot{\omega} &= -\frac{D}{2H}\omega - \frac{\omega_0}{2H}\Delta P_e \\ \Delta \dot{P}_e &= -\frac{1}{T'}\Delta P_e + \frac{1}{T'}v_f \end{aligned} \quad (16)$$

where

$$\Delta P_e = P_e - P_{m0}, \quad (17)$$

$$T' = \frac{x_{ds} T'_{d0}}{x_{ds}}, \quad (18)$$

$$\begin{aligned} v_f &= \frac{V_s}{x_{ds}} \sin \delta \left[ k_c u_f + T'_{d0} (x_d - x'_d) \frac{V_s}{x_{ds}} \sin \delta \omega \right] \\ &\quad + T' \frac{V_s}{x_{ds}} E_q \cos \delta \omega - P_{m0}. \end{aligned} \quad (19)$$

Note that the mechanical power control is represented as a constant power  $P_{m0}$ , i.e. the governor loop is relatively slow acting.

Now, we note (16) is a linear system with the new input  $v_f$ . Robust control techniques for linear systems [59, 60] can be employed. By solving an algebraic Riccati equation (ARE) – see [12, 54] for detail, the DFL compensating control law is obtained as

$$v_f = -k_\delta \delta - k_\omega \omega - k_P \Delta P_e \quad (20)$$

where  $k_\delta, k_\omega, k_P$  are the linear gains obtained from the solutions of ARE.

The real excitation control  $u_f$  can be obtained from (19) to give

$$\begin{aligned} u_f &= \frac{x_{ds}}{k_c V_s \sin \delta} \left[ v_f - T' \frac{V_s}{x_{ds}} E_q \cos \delta \omega + P_{m0} \right] \\ &\quad - T'_{d0} (x_d - x'_d) \frac{V_s}{k_c x_{ds}} \sin \delta \omega \end{aligned} \quad (21)$$

DFL nonlinear control (21) with (20) guarantees the transient stability of power system (6)–(8) for admissible uncertain  $x_L$  and  $V_s$  (proof is given in [12]). And in the post-fault period,

$$\begin{aligned} \lim_{t \rightarrow \infty} |\Delta \delta| &= 0, \\ \lim_{t \rightarrow \infty} |\omega| &= 0, \\ \lim_{t \rightarrow \infty} |\Delta P_e| &= 0. \end{aligned} \quad (22)$$

However, since  $V_t$  is a nonlinear function of  $\delta, P_e$  and the system structure, any change in the system structure will cause the voltage to reach another post-fault equilibrium point even if  $\delta$  and  $P_e$  are forced to go back to their prefault steady values. So the generator terminal voltage  $V_t$  could stay at a different post-fault state which is undesirable in practice.

From the above, we can see that although the DFL nonlinear compensator is effective for stability, it cannot guarantee voltage regulation. The simulation results shown later

in Section III-C.4 will verify that the DFL nonlinear controller enhances the transient stability of power systems but cannot by itself achieve a satisfactory post-fault voltage level.

### C.2 Voltage Controller

Voltage regulation is an important issue particularly in the post-transient period. Its basic objective is to regulate the voltage to reach its nominal value. Voltage controllers have been given in [14] using LQ-optimal techniques and in [15] using a linear robust control technique. Both of them have the problem that they deteriorate transient stability over the whole operating region.

For example, as proposed in [15], differentiating equation (15) gives

$$\Delta \dot{V}_t = f_1(t)\omega + \frac{f_2(t)}{T'_{d0}} \Delta P_e + \frac{f_2(t)}{T'_{d0}} v_f \quad (23)$$

where  $f_1(t)$  and  $f_2(t)$  are highly nonlinear functions of  $\delta, P_e$  and  $V_t$  – see [15] for details. Since  $f_1(t)$  and  $f_2(t)$  are dependent on the operating conditions, their bounds can be found within a certain operating region. So a new linearized system which is represented by the vector  $[\Delta V_t, \omega, \Delta P_e]$  can be developed. Robust linear control techniques can be applied to obtain

$$v_f = -k_V \Delta V_t - k_\omega \omega - k_P \Delta P_e \quad (24)$$

where  $k_V, k_\omega, k_P$  are linear gains dependent on the bounds of  $f_1(t), f_2(t)$ . The real excitation input  $u_f$  is chosen as defined in (21).

Since the voltage is introduced as a feedback variable in (24), the post-fault voltage is prevented from excessive variation. It is unnecessary to keep the power angle regulated once transient stability is assured.

However, since the design of the voltage controller involves estimating nonlinearity bounds within a certain operating region, it is only effective locally. In another words, when serious disturbances occur which cause the system to operate in a wider range outside the estimated one, the designed system may not perform well.

In conclusion, the voltage controller achieves voltage regulation, but it is only valid locally. This point will be verified in the simulations in Section III-C.4.

### C.3 Coordinated Control by Switching

By now it can be seen that the DFL nonlinear controller and voltage controller achieve different control objectives in different regions of the states. In [13, 54], a nonlinear coordinated control scheme was proposed where a switching strategy is used between the different control actions

to guarantee transient stability enhancement and voltage regulation.

A typical switching scheme is as follows:

*Step 1:* When the fault occurs at  $t = t_0$ , the DFL nonlinear controller  $u_f$  with (20) is employed to maintain the transient stability of power systems;

*Step 2:* At  $t = t_s$ , the control law switches to the voltage controller  $u_f$  with (24) to maintain the desired post-fault voltage level.

The switching time  $t_s$  should be reasonably chosen within the post-transient period, which requires that the fault sequence must be known as apriori. Further, the exact switching time has to be determined by trial and error in simulation. Thus, as the switching time is physically fixed according to one particular fault sequence, it may not be suitable for a different fault sequence, which may then destabilize the power system. Also, the switching time fixed in the first post-transient period cannot achieve voltage regulation over the whole working region allowing for later faults.

In summary, the obstacles preventing the switching strategy from robust practical success are as follows:

- The switching time is fixed;
- Not robustness with respect to different faults.

How to design a universal control law which is robust with respect to uncertain faults is a challenging problem. Before stating our global controller which overcomes these obstacles, we show in the next subsection simulation results of the controllers which were discussed above.

### C.4 Simulations of Local Controllers

The parameters of the SMIB power system which is shown in Figure 1 are as follows:

$$\begin{aligned} x_d &= 1.863, \quad x'_d = 0.257, \quad x_T = 0.127, \\ T'_{d0} &= 6.9, \quad x_L = 0.4853, \quad H = 4, \quad D = 5, \\ K_c &= 1, \quad x_{ad} = 1.712, \quad \omega_0 = 314.159. \end{aligned} \quad (25)$$

The physical limit of the excitation voltage is taken as

$$-3 \leq k_c u_f \leq 6 \quad (26)$$

The operating point of the power system used in the simulations is:

$$\delta_0 = 72^\circ, \quad P_{m0} = 0.9 \text{ p.u.}, \quad V_{t0} = 1.0 \text{ p.u.} \quad (27)$$

The fault is a symmetrical three phase short circuit fault with its sequences described as:

*Case 1. Permanent fault*

Stage 1: The system is in a pre-fault steady state;  
 Stage 2: A fault occurs at  $t = t_0$ ;  
 Stage 3: The fault is removed by opening the breakers of the faulted line at  $t = t_1$ ;  
 Stage 4: The system is in a post-fault state.

*Case 2. Permanent fault + increase of the mechanical input power*

Stage 1: The system is in a pre-fault steady state;  
 Stage 2: A fault occurs at  $t = t_0$ ;  
 Stage 3: The fault is removed by opening the breakers of the faulted line at  $t = t_1$ ;  
 Stage 4: The mechanical input power of the generator has a 30% step increase at  $t = t_2$ ;  
 Stage 5: The system is in a post-fault state.

*Case 3. Temporary fault + permanent fault*

Stage 1: The system is in a pre-fault steady state;  
 Stage 2: A fault occurs at  $t = t_0$ ;  
 Stage 3: The fault is removed by opening the breakers of the faulted line at  $t = t_1$ ;  
 Stage 4: The transmission lines are restored at  $t = t_3$ ;  
 Stage 5: Another fault occurs at  $t = t_4$ ;  
 Stage 6: The fault is removed by opening the breakers of the faulted line at  $t = t_5$ ;  
 Stage 7: The system is in a post-fault state.

We choose in the simulation  $t_0 = 0.1s, t_1 = 0.25s, t_2 = 1s, t_3 = 1.4s, t_4 = 2.1s, t_5 = 2.25s$ .

The fault location is indexed by a positive constant  $\lambda$  which is the fraction of the line to the left of the fault. The fault locations for the three cases of fault sequences are:

Case 1:  $\lambda = 0.035$ ;

Case 2:  $\lambda = 0.204$ ;

Case 3:  $\lambda = 0.04$ .

The controllers employed in the simulations are [15]:

Transient controller :

$$v_f = 22.36 \delta + 12.81 \omega - 82.45 \Delta P_e \quad (28)$$

Voltage controller :

$$v_f = -40.14 \Delta V_t + 10.11 \omega - 30.81 \Delta P_e \quad (29)$$

The power system responses with the different controllers subjected to different faults are shown in Figures 2-6. Figure 2 exhibits the closed-loop power system responses for three kinds of controllers in fault sequence Case 1. Figure 3 shows the responses for the transient nonlinear controller and voltage controller in Case 2, whereas the switching controller responses are shown in Figure 4 for different switching time. In fault sequence Case 3, the responses for the three controllers are shown in Figures 5 and 6.

From the simulation results it can be observed that the transient nonlinear controller stabilizes the disturbed systems but the post-fault voltage differs from the pre-fault

value by 10%-20%, which is not acceptable in practice. The voltage controller can only stabilize the system and maintain good post-fault voltage level in Case 1, but cannot survive more severe faults as in Case 2 and 3. For the switching controllers, the switching time is seen to be important since an inappropriate one causes the loss of synchronism of generators. This point is clearly shown in Figures 4 and 6 where the switching controller with switching time  $t_s = 1s$  stabilizes the system in Case 2, but destabilizes it in Case 3.

The simulation results are consistent with the analysis stated early in this Section. As stated in [13], surviving a severe transient disturbance and maintaining normal voltage values simultaneously are of key importance in power system control. The strategy by simply switching between different control actions is not reliable due to the non-existence of a universal switching time. In the next Section, we will propose a new global control strategy which achieves transient stability enhancement and voltage regulation simultaneously and robustly.

*D. Global Controller*

Our global control objective is to achieve good control performance over a wide range for the anticipated operating region. Specifically, we have the following control task.

**Global control problem:** *Design a smooth nonlinear feedback control law for the excitation system (6)-(8), such that the closed-loop power system is transiently stable when subjected to a severe disturbance, and restores the steady pre-fault voltage value after the disturbance.*

Desired properties of the global controller include robustness with respect to different faults whose sequences are not known apriori.

*D.1 Operating Region Membership Function*

From the analysis of the previous section, we find that if we introduce the power angle  $\delta$  in a feedback controller, transient stability of the system can be greatly improved. In practice, we want to achieve both transient stability enhancement and good post-fault performance of the system. In this context, good post-fault performance means that after the transient period we wish to control the excitation unit to regulate the generator terminal voltage  $V_t$ . According to the qualitatively distinct operating conditions and the corresponding control objectives over each region, local controllers are designed and coordinated through some strategy. We firstly need to define the operating regions and membership functions.

We use the following trapezoid-shaped like membership functions which are able to indicate different operating

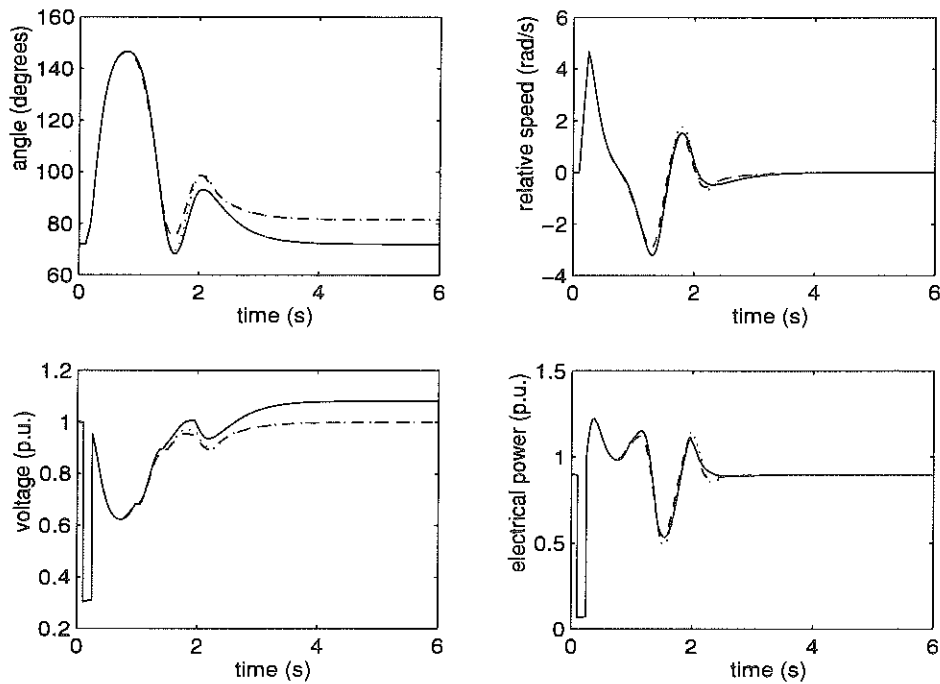


Fig. 2. Power system responses for *Case 1*: '—' DFL nonlinear controller; '---' voltage controller; '· · ·' switching controller ( $t_s = 1s$ ).

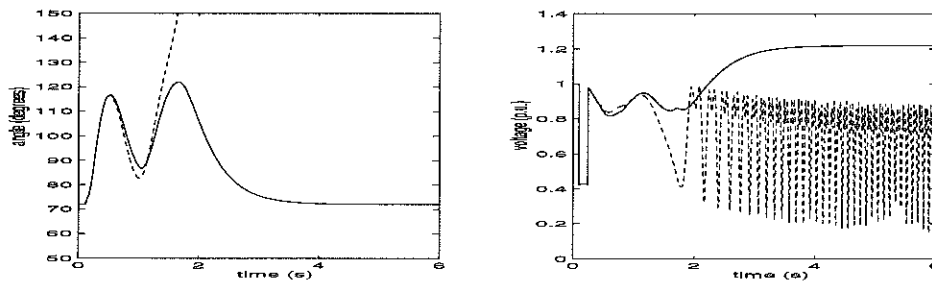


Fig. 3. Power system responses for *Case 2*: '—' DFL nonlinear controller; '---' voltage controller.

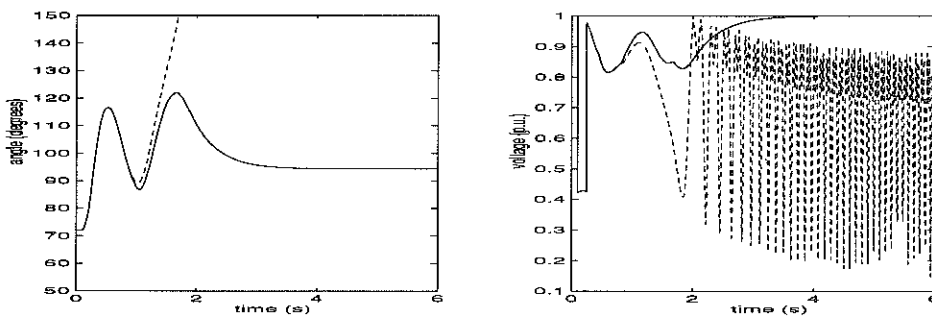


Fig. 4. Power system responses for *Case 2*, switching controller: '—'  $t_s = 1s$ ; '---'  $t_s = 0.8s$ .

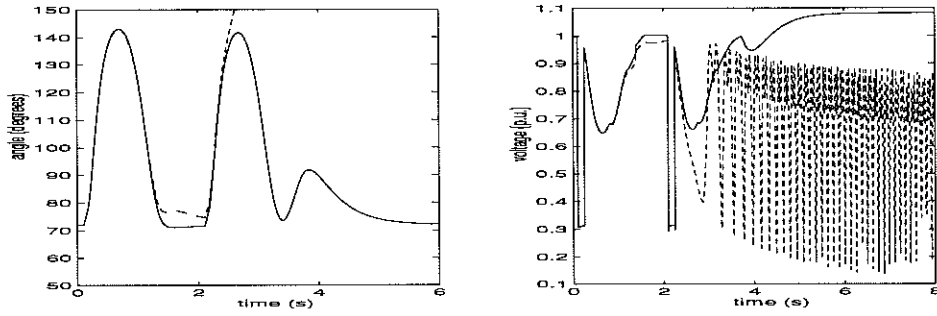


Fig. 5. Power system responses for Case 3: '—' DFL nonlinear controller; '---' voltage controller.

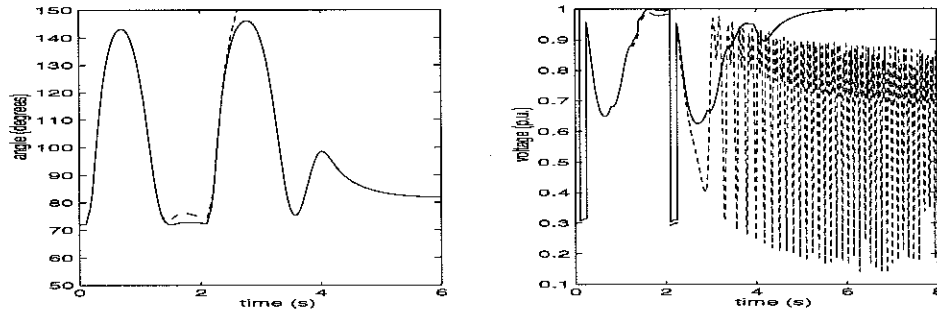


Fig. 6. Power system responses for Case 3, switching controller: '—'  $t_s = 1.3s$ ; '---'  $t_s = 1s$ .

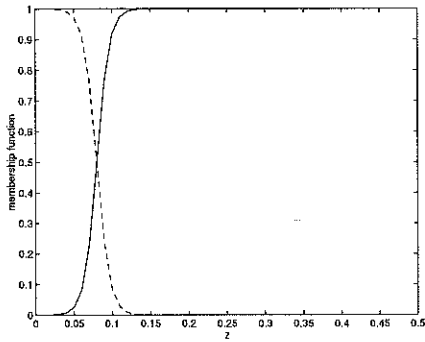


Fig. 7. Membership functions: '—'  $\mu_\delta$ , '---'  $\mu_V$ .

stages.

$$\begin{aligned} \mu_V(z) &= \left(1 - \frac{1}{1 + \exp(-120(z - 0.08))}\right) \\ &\quad \cdot \left(\frac{1}{1 + \exp(-120(z + 0.08))}\right) \\ \mu_\delta(z) &= 1 - \mu_V \end{aligned} \quad (30)$$

where

$$z = \sqrt{\alpha_1 \omega^2 + \alpha_2 (\Delta V_t)^2} \quad (31)$$

and  $\alpha_1, \alpha_2$  are positive design constants providing appropriate scaling which can be chosen according to different sensitivity requirement of power frequency and voltage.

Membership function (30) is plotted in Figure 7. It can be

seen that  $\mu_\delta(z)$  gets its dominant value when  $z$  is far away from the origin, which corresponds to the transient period; on the other hand,  $\mu_V(z)$  does so when  $z$  is close to the origin, which indicates the post-transient period. Since the membership function values are determined by the directly measurable variables,  $\omega$  and  $\Delta V$ , the fault sequence need not to be known beforehand.

Therefore, the whole operating region is partitioned into the following two subspaces by the membership functions, where  $S_1$  indicates the transient period and  $S_2$  indicates the post-transient period.

$$\begin{aligned} S_1 &= \{(\omega, \Delta V) | \mu_V \leq \mu_\delta\} \\ S_2 &= \{(\omega, \Delta V) | \mu_V > \mu_\delta\} \end{aligned} \quad (32)$$

The characteristic function of each subspace  $S_l$  ( $l = 1, 2$ ) is defined by:

$$\tau_l = \begin{cases} 1 & z \in S_l \\ 0 & \text{otherwise} \end{cases} \quad (33)$$

Note that  $\tau_1 + \tau_2 = 1$ .

It should be pointed out that  $\omega$  and  $\Delta V_t$  are chosen as the index variables in (31) since they sufficiently represent the operating status for the problem of transient stability and voltage regulation. If the problem under consideration is voltage stability, reactive power could be included in the index. Similarly, the proposed method can be extended to other power system control issues. The chosen membership functions have a trapezoid-like shape which is well known

in fuzzy control to separate operating conditions. From our simulation experience, the system performance is not sensitive to different parameters  $\alpha_1$  and  $\alpha_2$ .

#### D.2 Global Control Law

After the state space is partitioned, it is desirable that in the transient period, which corresponds to subspace  $S_1$ , the DFL nonlinear controller takes effect; while in the post-transient period, which corresponds to subspace  $S_2$ , the voltage controller does. The global control law is the average of the individual control laws, weighted by the operating region membership functions, i.e., the input  $v_f$  takes the form:

$$v_f = \mu_S v_{f1} + \mu_V v_{f2} \quad (34)$$

where  $v_{f1}$  is the DFL nonlinear controller (20) and  $v_{f2}$  is the voltage controller (24). The real excitation control  $u_f$  can be implemented by (21).

The global control (34) has the following interpretation: in the transient period system states are far away from the equilibrium, the primary control is to regulate them to enter a neighborhood of the equilibrium without large oscillations; then in the post-transient period around the equilibrium the voltage needs to be tuned to reach the pre-fault level. The membership functions play the role of appropriate weighting and smooth interpolation of the two controllers. One of the appealing abilities of the method is that the operating status is automatically distinguished by the membership functions which are functions of directly measurable variables. The form of control law (34) is such that a smooth transfer between the local controllers is automatically achieved.

The global heterogeneous control for transient stability and voltage regulation is illustrated in Figure 8, where block #1 and #2 represents local controllers, and membership functions play the role of appropriate coordination.

#### D.3 Discussion

The global control design procedure involves the following three steps:

- Qualitatively distinct operating regions are indicated by membership functions of directly measurable variables, and the region partitionings admit overlap;
- The control law in each region is specified to be the usual type of controller developed from model-based nonlinear control techniques: in the transient period, the controller is designed to dampen out the power angle oscillations quickly, while in post-transient period the voltage is regulated to return to the original equilibrium;
- The global control law is the weighted sum of local controllers, which achieves smooth transitions between the transient period and post-transient period.

The proposed global control law (34) features the following properties:

- Control action is determined by online measurement of power frequency and voltage, which makes it unnecessary to know the fault sequence beforehand;
- The controller is globally effective in the presence of different uncertain faults;
- The controller inherits the properties of local controllers, i.e., it is robust with respect to parameter uncertainties.

It should be pointed out that the design relies on a fixed system frequency, which may not be valid in a situation where the system frequency is abnormal. However, from our simulation experience, the global controller has certain robustness with respect to system frequency.

Simulation results follow to demonstrate the effectiveness of the heterogeneous control law.

#### D.4 Simulations of the Global Controller

In this subsection, we exhibit the closed-loop power system performances in the presence of different fault sequences and locations. The power system parameters and fault cases are the same as in Section III-C.4. The global control law employed is (34) with  $v_{f1}$  and  $v_{f2}$  from (28) and (29) respectively.

Figures 9-11 show the system performance when subjected to different faults as defined in Section III-C.4. In fault sequence *Case 1*, Figure 9 exhibits good transient performance and restoration of normal post-transient voltage. In fault sequence *Case 2*, Figure 10 shows similar performances; this contrasts with that in Figures 3 and 4 where unsatisfactory performances are observed for the voltage and switching controllers. In fault sequence *Case 3*, Figure 11 contrasts with Figures 5 and 6 in that both transient stability and normal post-fault voltage values are achieved. Figure 12 shows the angle and voltage responses with respect to different fault locations. From the simulations, we can see the global controller achieves the proposed control task and is robust with respect to different faults.

### IV. Emergency Voltage Control

#### A. Introduction

Electric power systems are designed, through careful planning and preventive control schemes, to survive most foreseeable disturbances [53]. Not all possible disturbances, however, can be foreseen at the planning stage and these may result in instability that will eventually lead to collapse or islanding of the system. The objective of an emergency control system is to detect such situations and carry out control actions necessary to prevent collapse of the system.

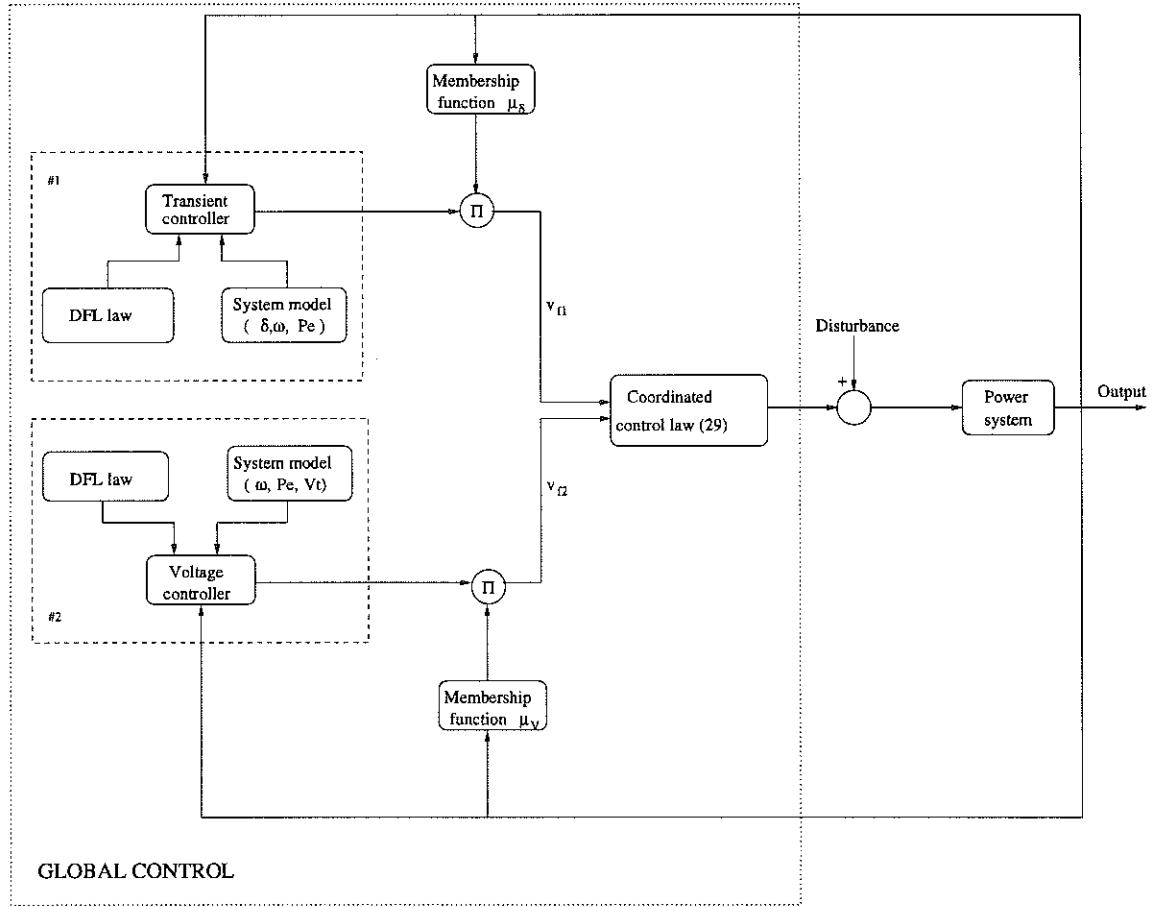


Fig. 8. Global controller for transient stability and voltage regulation.

The emergency controls considered here are: switching of capacitor banks, tap changer operation and load shedding. The principles of using these as efficient emergency controls have been established in [61–64]. The highly nonlinear nature of the problem calls for more sophisticated methods based on a dynamic system model in order to account for the current operating point and network state. In particular, proper coordination of all controls would minimize the amount of load shed. Most controls are inherently discrete in their nature; for example, capacitor banks and tap changers must be switched in fixed steps and while most utilities lack direct load control schemes, load shedding must still be carried out by disconnecting whole feeders.

Methods for coordination of secondary voltage control and load shedding using static system models have been described, eg in [65]. Coordination of dissimilar controls in the emergency state based on a dynamic system model has so far received little attention. A method based on differential dynamic programming and a security measure as the distance to the closest bifurcation has been derived in [1,3,66]. None of the above mentioned references fully take account of the discrete nature of controls or the inherent

dynamics of the loads.

This section demonstrates the application of model predictive control (MPC) to optimise emergency state voltage control. General model predictive control is well established for process control (see, eg [17,18,67] but the application to power systems network control is novel. A model of the controlled system, including the network and load dynamics, is used to predict the future system behaviour based on the current state and the applied control actions. The optimal control actions can then be obtained from the solution of a combinatorial optimization problem by a search method. Various predictors are employed, ranging from a detailed predictor based on simulation of the system to more computationally tractable linearized versions. The results presented here are based on the paper [2].

### B. System Modelling

Consider the simple power system in Figure 13. There are two loads, four capacitor banks and two on-load tap

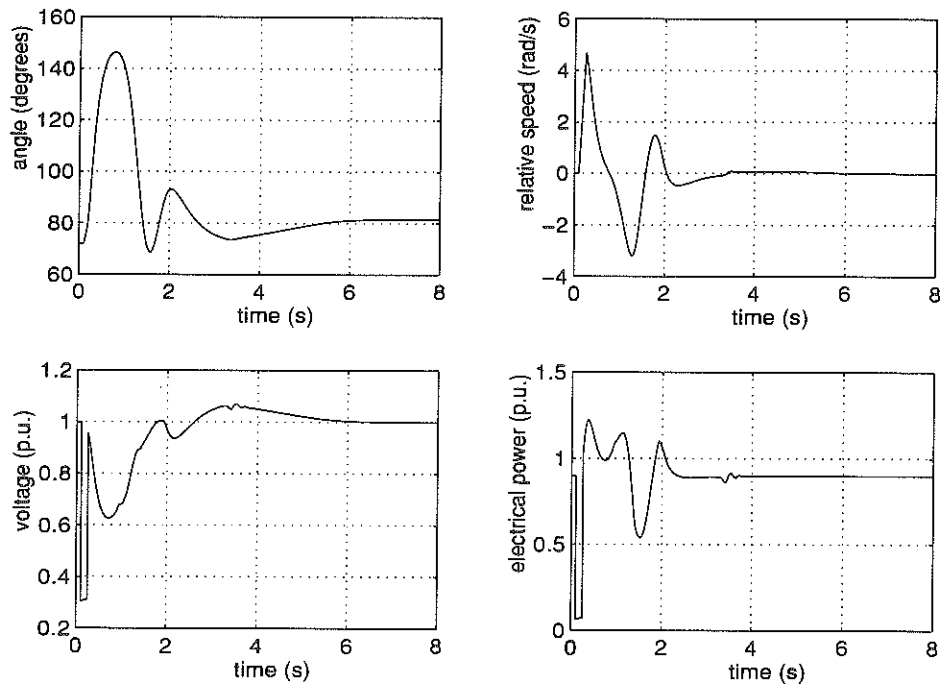


Fig. 9. Power system responses for Case 1: global control law.

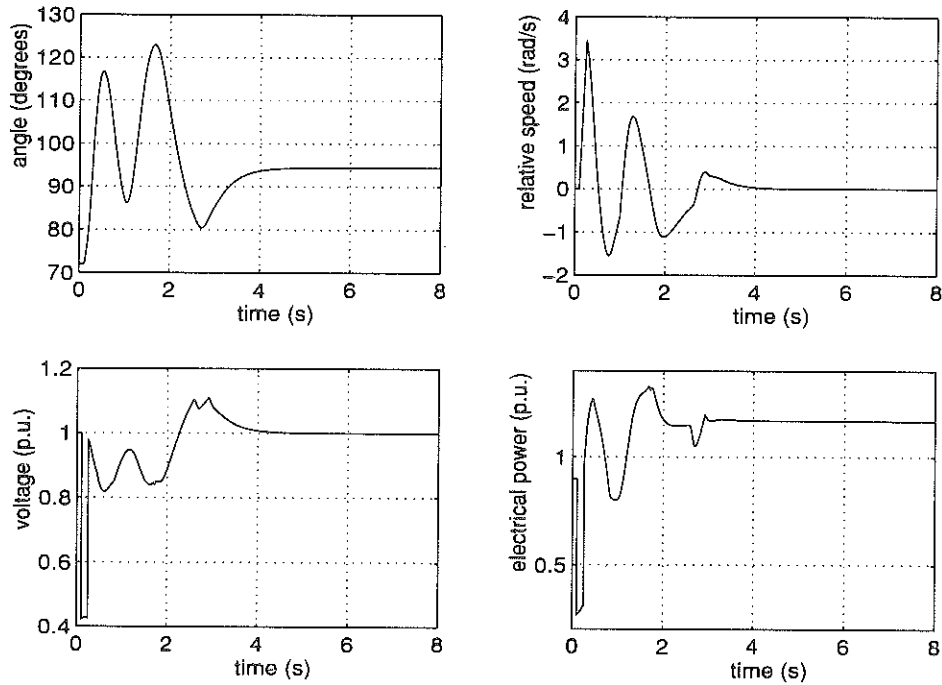


Fig. 10. Power system responses for Case 2: global control law.



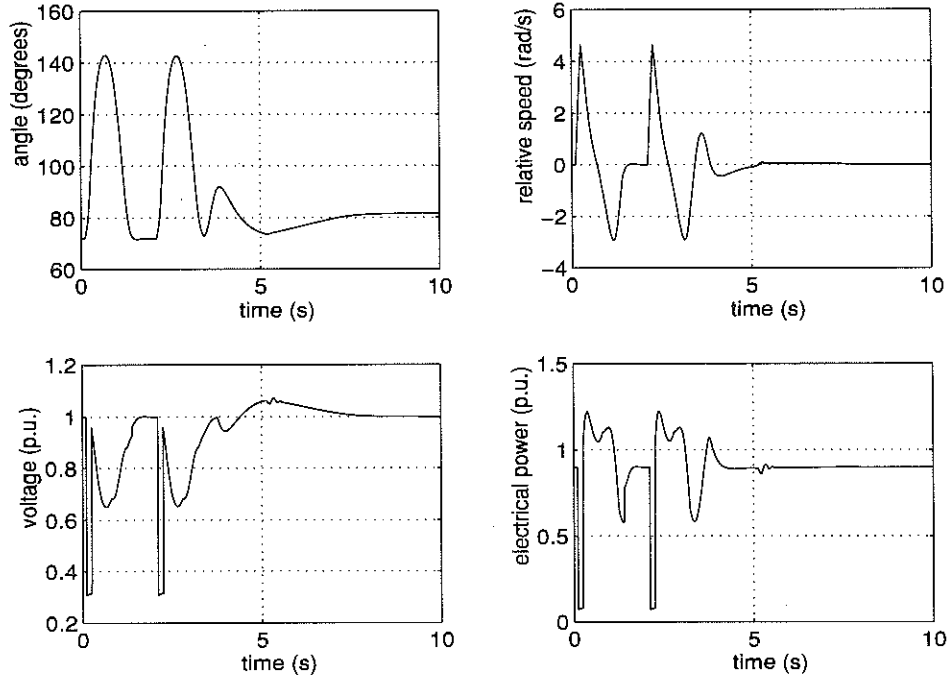
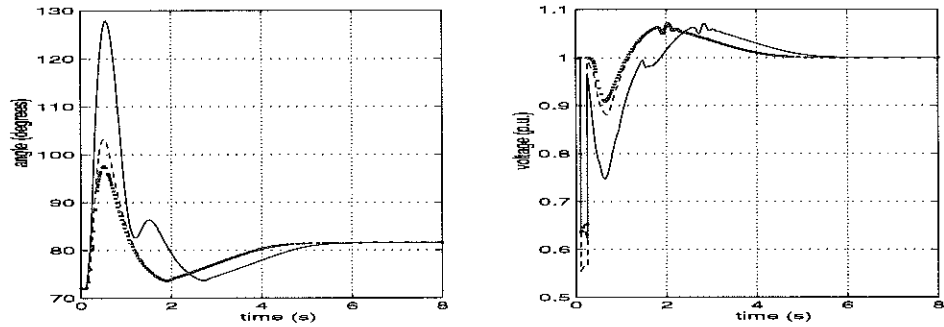


Fig. 11. Power system responses for Case 3: global control law.

Fig. 12. Power system responses for different fault locations in Case 1: (—)  $\lambda = 0.1$ ; (---)  $\lambda = 0.5$ ; (· · ·)  $\lambda = 0.8$ .

changing transformers considered as actuators. These can be operated in the discrete fixed steps given in Table II.

The generator at bus 1 is modelled as an infinite bus with fixed voltage and voltage angle while the generator at bus 2 is modelled using the standard sixth order dq-model with first order excitation system, an over-excitation limiter and a first order governor. The loads are modelled using the aggregate exponential recovery model [68]

$$T_p \dot{x}_p + x_p = P_s(V) - P_t(V) \quad (35)$$

$$P_d = k_l(x_p + P_t(V)) \quad (36)$$

where  $x_p$  is a continuous dynamic state that can be interpreted as a measure of the energy deficit in the load and  $P_s(V) = P_0 V^{\alpha_s}$  and  $P_t(V) = P_0 V^{\alpha_t}$  are the steady-state and transient voltage dependencies respectively.  $P_d$  is the

actual active load power and  $T_p$  is the active power recovery time constant. For the reactive load power, a similar model is used with corresponding characteristics  $Q_d$ ,  $x_q$ ,  $Q_s(V) = Q_0 V^{\beta_s}$ ,  $Q_t(V) = Q_0 V^{\beta_t}$  and time constant  $T_q$ . The scale factor  $k_l$  models load shedding and is applied to the reactive as well as to the active load model. The transformers are modelled as pure reactances in series with an ideal turns ratio change.

For the purpose of control determination, generators and their associated control systems are modelled more simply, using their quasi-steady state approximations given in [69], i.e., the derivative terms in the mechanical and flux equations are neglected.

A power system network model is conveniently expressed in the hybrid differential-algebraic-difference form given by

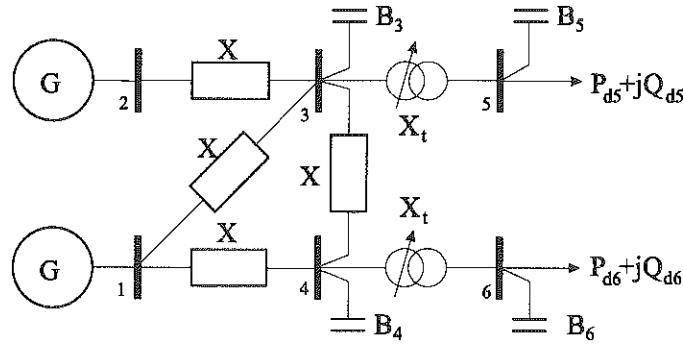


Fig. 13. Example power system studied.

equations (1,2,3).

### C. Control Problem Formulation

The basic principle of Model Predictive Control (MPC) is illustrated in Figure 14. A model predictive controller uses a system model to predict the future output trajectories (dotted lines) based on the current state and for several different candidate input sequences. A cost function is defined based on the deviation of each predicted trajectory from a desired trajectory (dashed line). The optimal control sequence, in the sense that it minimizes the defined cost function, is then obtained by solving an optimization problem on-line each time a new instance of the control sequence is to be determined. The optimal control is then applied to the system, until the next sample time. The interval between the current time  $t^*$  and the prediction horizon  $t^* + t_p$  is referred to as the prediction interval, and is chosen based on the settling time of the slowest dynamics. Usually, the prediction interval is chosen as a multiple of the sample time.

In the standard formulation, it is assumed that all control signals are continuous, i.e., can assume all values within some fixed range. In the case of a linear system this leads to an optimization problem that can be solved using quadratic programming whereas nonlinear programming is required with a nonlinear system.

Our application differs from the general nonlinear case in that the control variables are constrained to fixed discrete values which makes it necessary to resort to a combinatorial optimization method. In the standard formulation a sequence of control inputs, for the first  $n$  samples during the prediction horizon, is obtained from the optimization. The first control signal in this sequence is then applied to the plant, and the rest is discarded when the next optimization has been carried out. Here, when computing the new control signal, it is assumed that it will be in use during the entire prediction interval (that is,  $n = 1$ ).

Accordingly, the problem of selecting the new control vector  $u^+$  at the operating point  $(x^*, u^-) = (x(t^*), u(t^*))$  can

be formulated as the combinatorial optimization problem

$$\begin{aligned} & \text{minimize} && J(x^*, u) \\ & \text{subject to} && u \in \mathcal{S}(u^-) \end{aligned} \quad (37)$$

where  $u$  is the optimization variable corresponding to the new control state to be used during the interval  $[t^*, t^* + t_p]$  whereas  $u^-$  denotes the control state presently in use, in other words before the optimization starts at time  $t^*$ .  $\mathcal{S}(u^-)$  is the set of available control states at time  $t^*$  and is normally a function of  $u^-$ . The scalar function  $J(x^*, u)$  is referred to as a cost function and should evaluate the candidate control state  $u$  such that a smaller result indicates a more desirable state. Typically the cost function should include a component based on the deviations of the chosen outputs from their reference trajectories and a component based on the control variations.

Constraints can be imposed on inputs as well as states and outputs as follows:

- Input constraints, for example actuator limits, are modelled using the set of available control states. Since the set may be a function of the present control state, actuator ramp limits can also be handled. More specific constraints can also be represented. For instance, a useful constraint is to set priorities for control actions as in [1, 3, 66].
- Output and state constraints could be modelled as hard constraints by letting the cost function assume an infinite value, thus ensuring that a control state leading to a constraint violation is never selected. However, it is generally not desirable to impose hard constraints on the outputs or states since they may be impossible to strictly fulfil, and for large disturbances no control could be determined. Therefore output and state constraints are modelled as soft constraints by adding terms to the cost function that represent the "cost" of violating a (soft) constraint [70]. If this cost is dominant over other terms in the cost function, the primary aim of the controller will be to minimize any constraint violation.

Control actions are divided into two classes:

- Normal control measures that will be routinely scheduled; capacitor and tap changer operations belong to this

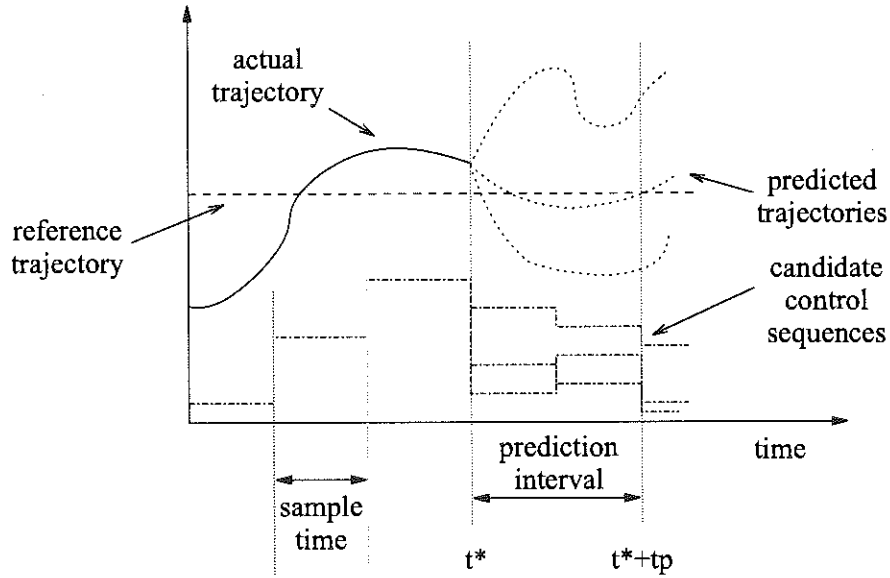


Fig. 14. Principle of Model Predictive Control.

category.

- Emergency control measures that will be scheduled only when required for the satisfaction of a constraint. This control is activated only if the constraint cannot be satisfied using any combination of the normal control measures. Load shedding belongs to this category.

The cost function is defined in the form

$$J(u^+, x^*) = \int_{t^*}^{t^*+t_p} ((\hat{y} - y_r)^T Q (\hat{y} - y_r) + (u^+ - u^-)^T R (u^+ - u^-) + P(t, x^*, u^+)) dt \quad (38)$$

where  $\hat{y} = \hat{y}(t, x^*, u^+)$  is a prediction of the output trajectory using information up to time  $t^*$  if the new piecewise constant control  $u^+$  is applied during the prediction interval. The control state presently in use is denoted  $u^-$ , the reference trajectory  $y_r$ , and the weighting matrices for output errors and control variations  $Q$  and  $R$  respectively. A special penalty term  $P(t, u^+, x^*)$  is introduced whenever a constraint violation or a singularity-induced bifurcation is predicted to occur within the prediction horizon ( $t \in [t^*, t^* + t_p]$ ). A suitable selection of  $Q$ ,  $R$  and  $P(t, u^+, x^*)$  ensures that none of the emergency controls are scheduled unless necessary to remove a constraint violation during the prediction interval.

### C.1 Predictors

The cost function is calculated from predictions of the output trajectories. Several different methods of obtaining (approximations of) these trajectories are possible [2]. The benchmark method is Nonlinear MPC (NLMPC). The system (1)–(3) is a hybrid nonlinear system and it is therefore

generally impossible to find an analytical expression for the trajectories ( $\hat{y}(t, u)$ ). The most straightforward method is to obtain them numerically. This requires simulation of the hybrid DAE model over the prediction interval for each evaluation of the cost function.

The NLMPC predictor is the most accurate method. It makes use of the full simulation model and thus accounts for hybrid as well as nonlinear behaviour of the system.

In [2], the performance of NLMPC is compared with various approximate prediction methods:

- Euler State Prediction (ESP);
- MPC using off-equilibrium linearisations (LMPC);
- Euler state prediction – linear output approximation (ESPLO).

The details are more to do with numerical methods than the ideas of this paper. Nevertheless, it is an important topic for practical implementation – see [2] for further discussion.

### D. A Tree Search Method

The combinatorial optimization problem (37) can be seen as a search problem, where the search state-space is given by the control constraints. The set of available control states  $S(u)$  is explored for a best control state using the standard recursive depth-first algorithm [71] shown in Table I. The algorithm relies on two auxiliary functions:

$s(u)$  which generates all control states reachable from the current state  $u$  with a single switching of one control, that is, the subset of  $S(\Pi)$  reachable from the state  $u$  by the

TABLE I

PSEUDOCODE FOR CONSTRUCTION AND TRAVERSAL OF THE SEARCH TREE.

```

[ $f_{out}$ ] = function search ( $f_{in}$ ,  $u_{in}$ ,  $m$ );
 $f$  = call  $c(u_{in})$ 
if  $m = 1$  /* the node is a leaf node */
    best =  $f$ 
else
    best = min( $f$ ,  $f_{in}$ )
    for  $u_i$  = call  $s(u_{in})$  do
         $f_{tree}$  = call search( $f_{in}$ ,  $u_i$ ,  $n - 1$ )
        best = min( $f_{tree}$ , best)
    end
return  $f_{out} = best$ 

```

|           |   |                                          |
|-----------|---|------------------------------------------|
| $f_{in}$  | - | best value found prior to search of tree |
| $u_{in}$  | - | initial (root) control state             |
| $m$       | - | search depth                             |
| $f_{out}$ | - | best value found after search of tree    |

switching of a single control.

$c(u)$  which evaluates the state  $u$ , according to the cost criteria Eq. (38).

Figure 15 shows the search tree for a simplified search problem where only the controls  $B_3$  and  $B_4$  in Figure 13 are enabled; an additional constraint that each control may only change once in the tree has been imposed. The number shown below each node corresponds to the result reported by the function *search*. The search starts at the initial state (1) with  $B_3 = 0.15$ ,  $B_4 = 0.15$ , corresponding to the root of the tree. From here four new states can be reached (2, 5, 8, 11) by changing either  $B_3$  or  $B_4$  one step up or down. From each of these four states another two can be reached by changing the other control. Here the optimum is found in nodes 3 and 9 for  $B_3 = 0.3$ ,  $B_4 = 0.3$ . Note that the search tree (13 nodes) is larger than the state space ( $3^2 = 9$  possible combinations) since it contains not only all possible control states but also all paths to them. The example search requires 13 evaluations of the cost-function.

For this simple example, the search state space is limited by the control constraints because of the small number of controls. However, the tree grows exponentially with the number of controls and an exhaustive search of the tree is not feasible for practical cases. With a larger number of controls, the size of the tree is limited by applying a maximum search depth. This search depth consequently corresponds to the maximum number of controls that may change in one search.

### E. Simulation Results

To illustrate the performance of the emergency controllers, results from simulation of the system in Figure 13 are presented in Figs. 17-18. The disturbances applied are changes of the four line impedances from  $X=0.2$  to  $X=1.0$  p.u. If no emergency actions are taken, voltage collapse will occur at simulation time 70 s as shown in Figure 16. This figure also shows the response with a more detailed model including the fast electromechanical oscillations. The simulations have been carried out with a 30 s sampling interval of the controller, i.e. the tree-search optimization is carried out periodically every 30 s. By the use of voltage constraints, load shedding is authorized if the voltages at bns 5 or 6 are predicted to be lower than 0.9 p.u. at the prediction horizon. The search depth is 4, the prediction horizon 120 s and the weight matrices and penalty terms were chosen according to particular tuning procedure in [2], with the output vector  $y$  containing the voltages of buses 5 and 6.

Figure 17 shows the voltage response at buses 5 & 6 with all controls enabled. In this case, it is possible to stabilize the system without resorting to load shedding. All the predictors yield near identical results. The NLMPC stabilizes and restores the voltages close to their pre-disturbance levels using 5 capacitor bank steps and 6 tap changer operations. In [2] it is shown that more approximate predictors are capable of stabilizing the voltage with less computation, but use an extra capacitor switching for a total of 6.

Figure 18 shows the voltage response to the same disturbance but with capacitor controls  $B_5$  and  $B_6$  disabled. The NLMPC stabilizes the voltages using 4 capacitor steps, 5 tap changer operations and 4 load shedding steps.

Here, the tap changer positions are explicitly controlled by the emergency controller. Normally, the two tap changing transformers would be under feedback control by relays such as those described by for example [72]. Thus, the emergency control applicable to tap changers would normally be tap locking. Reference [2] discusses use of search heuristics to reduce computation.

### F. Other Possibilities

The results presented here consider emergency state operation. The same methodology can be used in an implementation that provides control coordination aimed at loss minimization in the normal state and for arresting voltage collapse in the emergency state. The cost function would be based on system active power losses and two sets of voltage constraints would be used, for the normal and emergency states respectively. In principle the methodology described here could be applied to any kind of stability problem in power systems.

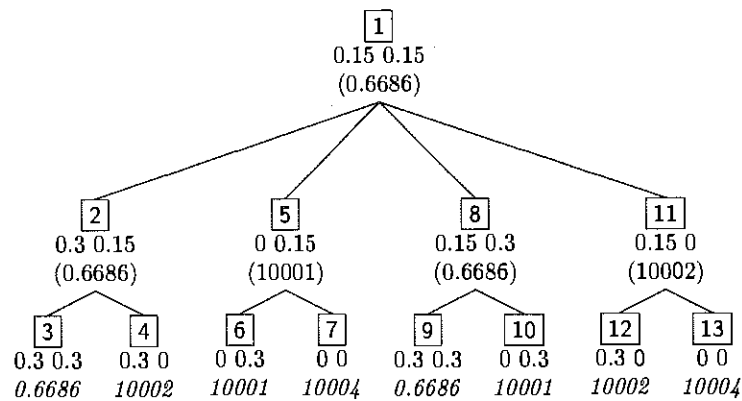


Fig. 15. Search example

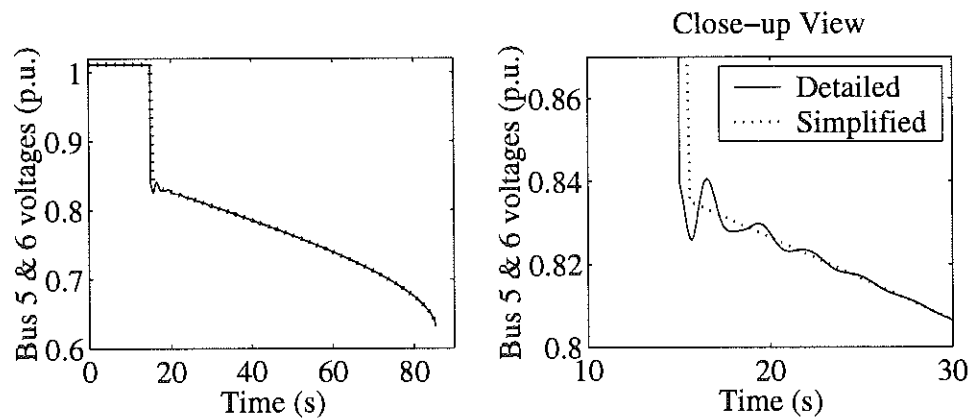


Fig. 16. Voltage response without voltage control.

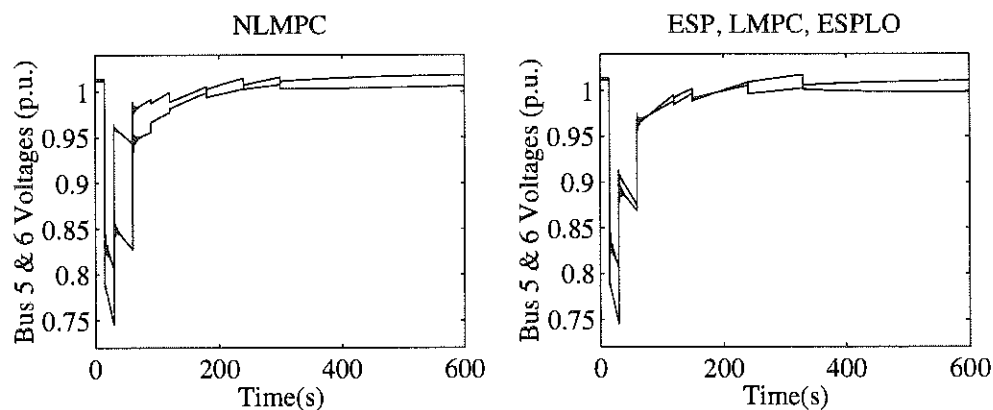


Fig. 17. Voltage response at buses 5 and 6 with all controls enabled.

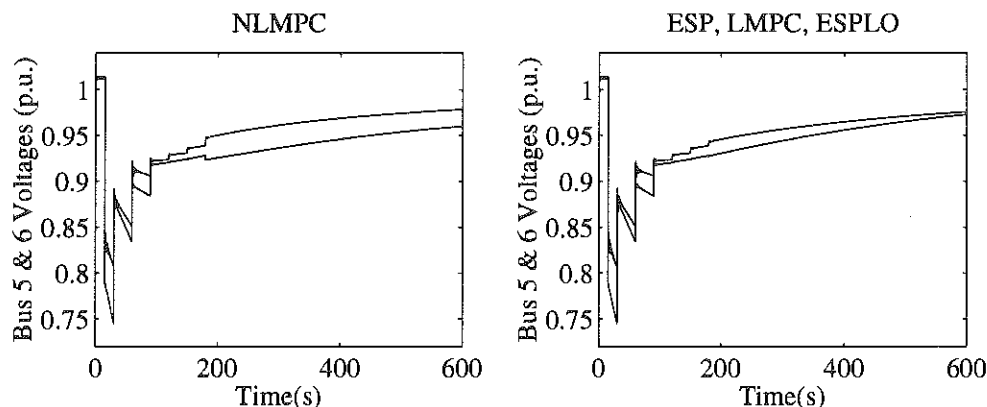


Fig. 18. Voltage response at buses 5 and 6 with  $B_5$  and  $B_6$  disabled. The three methods in the right hand figure yield identical results.

## V. Conclusions

This paper has given a conceptual framework, called global control, for the control of complex systems. The term global refers to scale (in dimension or geographically) and size of disturbances as is clearly needed for the world's larger power systems. The combination of ideas developed in control science, optimisation and related to the specific structure of power systems provides the possibility of more advanced control in the era of deregulation where more complexity is going to be inevitable. The framework involves hybrid system modelling, bifurcation analysis, switching control and optimal coordination and scheduling of control. Two special control tasks were investigated in more detail. Firstly, we showed how global control can even improve the coordination of multi-objective control of a single machine on an infinite bus power system. We defined our global control objective as achieving satisfactory control performance over a wide range of anticipated operating conditions; specifically, transiently stabilizing the power system when subjected to a severe disturbance and retaining good voltage level after the disturbance. The controller was of the switching kind using membership functions. The second illustration demonstrates use of coordinated control by the application of Model Predictive Control to emergency voltage control. The controller optimally coordinates capacitor switching, tap changer operation, and load shedding in different geographic locations, ensuring minimum usage of emergency controls such as load shedding. A search method is employed to minimize a cost function based on predictions of the system's future behaviour.

## VI. Appendix: System Data

See Tables II and III.

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TABLE II  
CONTROL VARIABLES (ALL DATA GIVEN IN P.U.)

| symbol    | control | initial value | lower limit | upper limit | control step |
|-----------|---------|---------------|-------------|-------------|--------------|
| $B_3$     | cap. 3  | 0.00          | 0.00        | 0.30        | 0.15         |
| $B_4$     | cap. 4  | 0.00          | 0.00        | 0.30        | 0.15         |
| $B_5$     | cap. 5  | 0.00          | 0.00        | 0.30        | 0.15         |
| $B_6$     | cap. 6  | 0.00          | 0.00        | 0.30        | 0.15         |
| $k_{t35}$ | tap 3-5 | 1.04          | 0.80        | 1.20        | 0.02         |
| $k_{t46}$ | tap 4-6 | 1.06          | 0.80        | 1.20        | 0.02         |
| $k_{l5}$  | load 5  | 1             | 0.85        | 1           | 0.05         |
| $k_{l6}$  | load 6  | 1             | 0.85        | 1           | 0.05         |

TABLE III  
NETWORK, GENERATOR & LOAD PARAMETERS

| Load                                                                                                   | Generator (at bus 2)                     |
|--------------------------------------------------------------------------------------------------------|------------------------------------------|
| $P_{05} = P_{06} = 0.6$ p.u.                                                                           | $V_r = 1.05$ p.u.                        |
| $Q_{05} = Q_{06} = 0.3$ p.u.                                                                           | $P_m = 0.3$ p.u.                         |
| $T_{p5} = T_{p6} = 60$ s                                                                               | $H = 3.54$ MVA/MWs, $D = 0.0$ p.u.       |
| $T_{q6} = T_{q8} = 60$ s                                                                               | $r_a = 0.00327$ p.u.                     |
| $\alpha_{s5} = \alpha_{s6} = 0$                                                                        | $x_d = 1.76$ p.u., $x_q = 1.58$ p.u.,    |
| $\alpha_{t5} = \alpha_{t6} = 2$                                                                        | $x'_d = 0.42$ p.u., $x'_q = 0.30$ p.u.   |
| $\beta_{s5} = \beta_{s6} = 0$                                                                          | $x''_d = 0.10$ p.u., $x''_q = 0.20$ p.u. |
| $\beta_{t5} = \beta_{t6} = 2$                                                                          | $T'_{d0} = 6.66$ s, $T'_{q0} = 0.44$ s   |
| <b>Network</b>                                                                                         | $T''_{d0} = 0.02$ s, $T''_{q0} = 0.03$ s |
| $n_{max} = 1.2$ p.u.                                                                                   | <b>Exciter &amp; AVR (at bus 2)</b>      |
| $n_{min} = 0.8$ p.u.                                                                                   | $T_{exc} = 2.5$ s                        |
| $X_t = 0.1$ p.u.                                                                                       | $K_{avr} = 100$                          |
| $T_t = 30$ s                                                                                           | $E_{fmax} = 3.5$ p.u.                    |
| $X = \begin{cases} 0.2, & \text{time} < 15 \text{ s} \\ 1.0, & \text{time} > 15 \text{ s} \end{cases}$ | $E_{fmin} = -3.5$ p.u.                   |
| $V_1 = 1.05 \angle 0$ p.u.                                                                             |                                          |

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## Nonlinear Stabilizing Control Using State-Space Linearization

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**Abstract:** This paper presents the results of simulator tests for an advanced power system stabilizer (APSS) using the theory of nonlinear feedback control. The conventional PSS was designed by linearizing under one operating point. Therefore the possibility exists that the PSS does not operate effectively after the power system changes drastically. If a nonlinear power system is linearized at all operating points, the damping controller operates effectively under various kinds of conditions. The generator control system was designed using an exact linearization approach toward one machine-infinite bus model. Furthermore to evaluate the dynamic performance of this controller for nonlinear operating points, digital simulations and real-time digital simulator tests were performed. The effect of the nonlinear control was compared with the effect of ( $\Delta P + \Delta \omega$ ) input type PSS.

### 1. Introduction

Recently restrictions on economy and environmental impact are placing new demands on effectiveness in bulk power transmission systems employed at high power transmission levels. From theoretical development of nonlinear control, linearized control by feedback has become one of the most powerful candidates to deal with the problem of interarea poorly-damped oscillations. Isidori [1] systematically interpreted the law of the feedback which linearizes control of a nonlinear system. The authors have linearized the generator control system including the AVR and governor (GOV) strictly, and showed the effect in decentralized control by digital simulations [2],[3]. Furthermore, the authors verified the effect of the developed nonlinear control by simulator tests.

This paper consists of the following. Section 2 presents the nonlinear model of the multi-machine system containing the AVR and GOV. In Section 3, the exact linearizing technique by coordinates transformation and feedback and the design method of the linear controller are described. In Section 4, the technique of presuming system information using only the local measurement values is described because power system information is required for exact linearization. Section 5 summarizes verification results by simulator tests.

### 2. State equation of nonlinear system

It is assumed that an external multi-machine power system is one machine-infinite bus model (Fig. 1). The dynamics such as power swing and voltage deviation of this system is expressed by the transient model of Park's generation equations (1) and excitation governor system equations (2). For example electrical power  $P_e$  and

generator d axis current  $I_d$  are expressed using the trigonometric functions of internal phase angle, because  $P_e$  and  $I_d$  have strong nonlinear characteristics. AVR and GOV dynamic characteristics are expressed by the simple block shown in the figure.

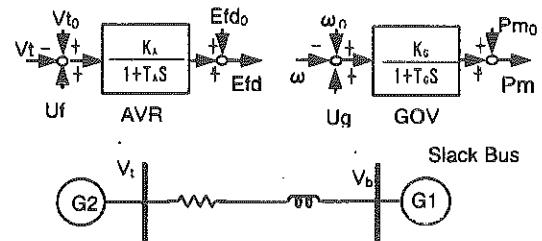


Fig.1. One machine-infinite bus model

$$\left. \begin{aligned} \dot{\delta} &= \Delta\omega & \dot{\omega} &= \frac{W_0}{2H} \left[ P_m - P_e - \frac{D}{W_0} \Delta\omega \right] \\ \dot{E}'_q &= \frac{1}{T_{d0}} \left[ -E'_q - (x_d - x'_d) I_d + E_{fd} \right] & W_0 &= 2\pi f_0 \end{aligned} \right\} \quad (1)$$

$$\left. \begin{aligned} \dot{E}_{fd} &= -\frac{NE_{fd}}{T_A} + \frac{K_A}{T_A} \Delta V_t + \frac{K_A}{T_A} U_f & (AVR) \\ \dot{P}_m &= -\frac{P_m}{T_G} + \frac{K_G}{T_G} \frac{\Delta\omega}{W_0} + \frac{P_0}{T_G} + \frac{K_G}{T_G} U_G & (GOV) \end{aligned} \right\} \quad (2)$$

2H: inertia constant (MW-Sec/MVA) D: damping (p.u.)  
Pm: mechanical power(p.u.) Pe: electrical power (p.u.)  
Eq': internal voltage (p.u.) Efd: field voltage (p.u.)  
Uf: excitation system control signal  
UG: speed governor control signal

The state equation of the one machine-infinite bus system can be expressed by (3) from these differential equations (1) and (2).

$$\left. \begin{aligned} \dot{X} &= F(X) + G \cdot U \\ Y &= H(X) \end{aligned} \right\} \quad (3)$$

Here

$$\left. \begin{aligned} X &= [\Delta\delta, \Delta\omega, E'_q, E_{fd}, P_m]^T \\ U &= [U_f, U_G]^T \\ Y &= [\Delta\delta, \Delta V_t]^T = [h_1(X), h_2(X)]^T \\ G &= [g_1, g_2]^T \\ g_1 &= \left[ 0 \quad 0 \quad 0 \quad \frac{K_A}{T_A} \quad 0 \right]^T \\ g_2 &= \left[ 0 \quad 0 \quad 0 \quad 0 \quad \frac{K_G}{T_G} \right]^T \end{aligned} \right\} \quad (4)$$

### 3. Controller design by exact linearization

The nonlinear system expressed with (3) is exactly linearized by coordinates transformation and feedback. That is, new output  $Z$  and new input  $V$  shown in (5) and (6) are considered.

$$Z = \Phi(x) \quad (5)$$

$$U = V / \beta(x) - \alpha(x) / \beta(x) \quad (6)$$

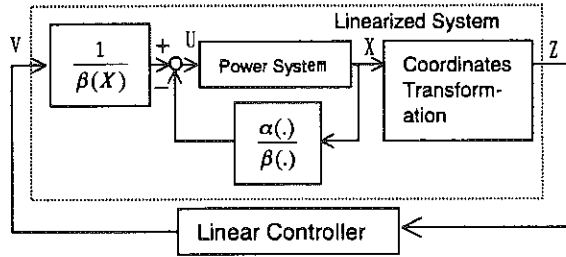


Fig.2. Exact linearization of nonlinear system

If the state equation (3) satisfies the theorem of Frobenius, function  $h(x)$  surely exists. One of the coordinates transformation and the feedback that linearize a system are as follows.

$$Z = \Phi(x) = \begin{bmatrix} h(x) \\ L_f h(x) \\ L_f^2 h(x) \\ \vdots \\ L_f^{n-1} h(x) \end{bmatrix} \quad (7)$$

$$U = \frac{V}{\beta(x)} - \frac{\alpha(x)}{\beta(x)} = L_g L_f^{n-1} h(x) V + L_f^n h(x) \quad (8)$$

The scalar function Lie-derivatives of scalar function  $h(x)$  with respect to vector field  $F(x)$  are defined as follows.

$$L_f h(x) = \frac{\partial h(x)}{\partial x} \cdot F(x) \quad (9)$$

Here  $1/\beta(x)$  is the coefficient of input transformation and  $\alpha(\cdot)/\beta(\cdot)$  is the gain of linearization feedback. The scalar functions  $\alpha(x)$  and  $\beta(x)$  are defined in [2] specifically.

The linearized system can be expressed with (10) and (11).

$$\dot{Z} = A \cdot Z + B \cdot V \quad (10)$$

$$Z = \begin{bmatrix} \Delta \delta \\ \Delta \omega \\ \dot{\omega} \\ \Delta V_t \\ \dot{V}_t \end{bmatrix} \quad (11)$$

$$A = \begin{bmatrix} 0 & 1 & 0 & 0 & 0 \\ 0 & 0 & 1 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 1 \\ 0 & 0 & 0 & 0 & 0 \end{bmatrix} \quad V = \begin{bmatrix} V_1 \\ V_2 \\ V_3 \\ V_4 \\ V_5 \end{bmatrix}$$

$$B = \begin{bmatrix} 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & -1 & 0 \\ 0 & 0 & 0 & 0 & 0 \\ 0 & -1 & 0 & 0 & 0 \end{bmatrix}$$

To design the optimum controller, the performance index function  $J$  (12) is selected with regard to the multi-input multi-output system (10).

$$J = \int_0^\infty [Z^T Q Z + V^T R V] \quad (12)$$

The feedback control input variable  $V$  that minimizes the performance index function  $J$  is found,

$$V = -R^{-1} B^T P X \quad (13)$$

where  $P$  is a nonnegative solution of the following Riccati equation,

$$A^T P + P A + Q - P B R^{-1} B^T P = 0 \quad (14)$$

when

$$\begin{aligned} Q &= \text{diag}(500, 90000, 500, 500, 500) \\ R &= \text{diag}(1, 1, 1, 1, 1) \end{aligned} \quad (15)$$

then

$$\begin{aligned} V_2 &= 22.4 \Delta V_t + 23.3 \dot{V}_t \\ V_4 &= 22.4 \Delta \delta + 302.5 \Delta \omega + 33.2 \dot{\omega} \end{aligned} \quad (16)$$

### 4. Estimation of system information values

In order to linearize a power system exactly, it is necessary to calculate  $\alpha(x)$  and  $\beta(x)$  shown by (6) according to the operation point. Then, these scalar functions are derived only from the active power, the reactive power, and terminal voltage of generator. In the proposed method, the multi-machine system seen from the generator terminal is modeled equivalently as an infinite bus and a transmission line. The partials for a particular machine are given by (17) using resistance  $R_e$  and the reactance  $X_e$  of the transmission line [4].

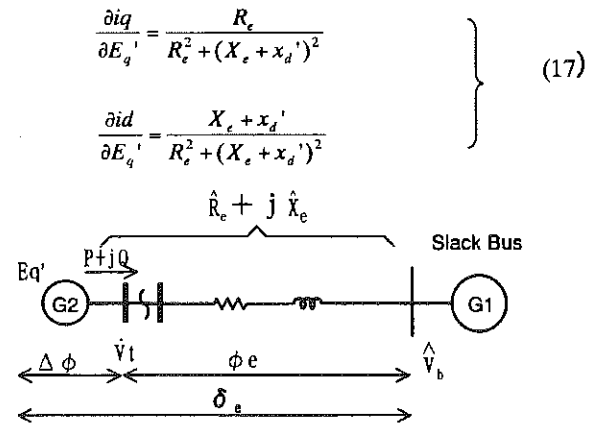


Fig.3. Estimation of system information values

There is a technique that determines the equivalent reactance and equivalent voltage of a power system [5]. However, in an actual multi-machine system, system load exists near the generator and there has been a problem that the place of the load can not be pinpointed. On the other hand, even if a system load exists, the devised method can presume a power system equivalent. That is, it is possible to consider existence of a load by presuming equivalent series resistance of a power system. Expression (18) relates the active power  $P$ , reactive power  $Q$ , terminal angle from system voltage  $\phi_e$ , terminal voltage  $V_t$ , system equivalent resistance  $R_e$ , the system equivalent reactance  $X_e$  and the system equivalent voltage  $V_b$ .

$$P = \{R_e \cdot (V_i^2 - V_i \cdot V_b \cdot \cos \phi_e) + X_e \cdot V_i \cdot V_b \cdot \sin \phi_e\} / (R_e^2 + X_e^2) \quad (18)$$

$$Q = \{X_e \cdot (V_i^2 - V_i \cdot V_b \cdot \cos \phi_e) - R_e \cdot V_i \cdot V_b \cdot \sin \phi_e\} / (R_e^2 + X_e^2)$$

Terminal angle  $\phi_e$  can be eliminated in the simultaneous equations (18), then the relation  $I_g^2 V_i^2 = P^2 + Q^2$  gives the following.

$$(R_e^2 + X_e^2) \cdot I_g^2 - 2(Q \cdot X_e + P \cdot R_e) + V_i^2 - V_b^2 = 0 \quad (19)$$

$V_b$ ,  $R_e$ , and  $X_e$  are considered constant and 3 sets of  $(I_{g1}^2, Q_1, P_1, V_{i1})$ ,  $(I_{g2}^2, Q_2, P_2, V_{i2})$ ,  $(I_{g3}^2, Q_3, P_3, V_{i3})$  measurements are obtained during the transient oscillation of the generator.

$$\left. \begin{aligned} (R_e^2 + X_e^2) \cdot I_{g1}^2 - 2(Q_1 \cdot X_e + P_1 \cdot R_e) + V_{i1}^2 - V_b^2 &= 0 \\ (R_e^2 + X_e^2) \cdot I_{g2}^2 - 2(Q_2 \cdot X_e + P_2 \cdot R_e) + V_{i2}^2 - V_b^2 &= 0 \\ (R_e^2 + X_e^2) \cdot I_{g3}^2 - 2(Q_3 \cdot X_e + P_3 \cdot R_e) + V_{i3}^2 - V_b^2 &= 0 \end{aligned} \right\} \quad (20)$$

The simultaneous equations (20) are solved and the equivalent resistance  $R_e$ , the equivalent reactance  $X_e$  and the equivalent voltage  $V_b$  are obtained.

When (18) is solved for  $\phi_e$ ,

$$\phi_e = \cos^{-1} \left[ \frac{(R_e V_i^2 / \sqrt{R_e^2 + X_e^2} - P \cdot \sqrt{R_e^2 + X_e^2}) / V_i V_b}{-\arg(R_e + jX_e)} \right] \quad (21)$$

Then, substituting the presumed  $R_e$ ,  $X_e$  and  $V_b$  into (21) gives

$$\phi_e = \cos^{-1} \left[ \frac{(\hat{R}_e V_i^2 / \sqrt{\hat{R}_e^2 + \hat{X}_e^2} - P \cdot \sqrt{\hat{R}_e^2 + \hat{X}_e^2}) / V_i \hat{V}_b}{-\arg(\hat{R}_e + j\hat{X}_e)} \right] \quad (22)$$

As shown in Fig.4, the internal rotor angle  $\Delta \phi$  is the phase difference between the effective internal voltage phasor  $E_q'$  and the armature terminal voltage phasor  $V_t$ . The angle  $\Delta \phi$  is calculated by (23)[6].

$$\Delta \phi = \arctan \left( \frac{V_d}{V_q} \right) \quad (23)$$

Where  $V_d$  is the d-axis component of the armature terminal voltage and  $V_q$  is the q-axis component. These dq components are obtained by (24) using  $P$ ,  $Q$  and  $V_t$  of the local generator terminal.

$$\left. \begin{aligned} i_q &= \frac{P \cdot V_i}{\sqrt{(P \cdot X_q)^2 + (V_i^2 + X_q \cdot Q)^2}} \\ V_d &= X_q \cdot i_q \\ V_q &= \sqrt{V_i^2 - X_q^2 \cdot i_q^2} \end{aligned} \right\} \quad (24)$$

As mentioned above, the presumed value of the internal rotor angle from system voltage is calculated by (25).

$$\delta_e = \phi_e + \Delta \phi \quad (25)$$

The obtained internal rotor angle  $\delta_e$  is used as an input signal for the nonlinear controller.

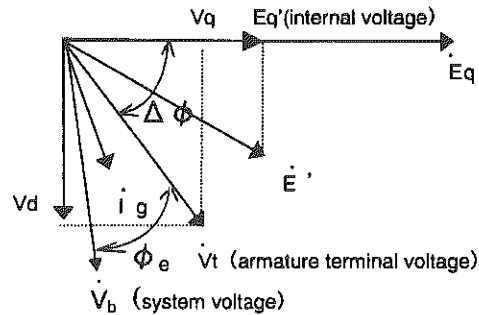


Fig.4 Steady-state generator phasor diagram

## 5. Verification of nonlinear control effect

### 5.1 Nonlinear control system configuration

Fig. 5 shows the nonlinear control system configuration. The inputs of the nonlinear controller are angular velocity of the rotor  $\omega$ , active power  $P$ , reactive power  $Q$  and the armature terminal voltage  $V_t$ . The control outputs of the nonlinear controller are the excitation system control signal  $U_f$  and the speed governor control signal  $U_G$ . The generator internal parameter and power system equivalent impedance and voltage are required for input transformation and exact linearization via feedback. This nonlinear controller estimates these parameters using active power  $P$ , reactive power  $Q$  and the armature terminal voltage  $V_t$ . Moreover the magnetic field voltage

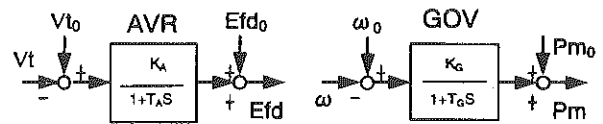


Fig.6. Simplified AVR and GOV block

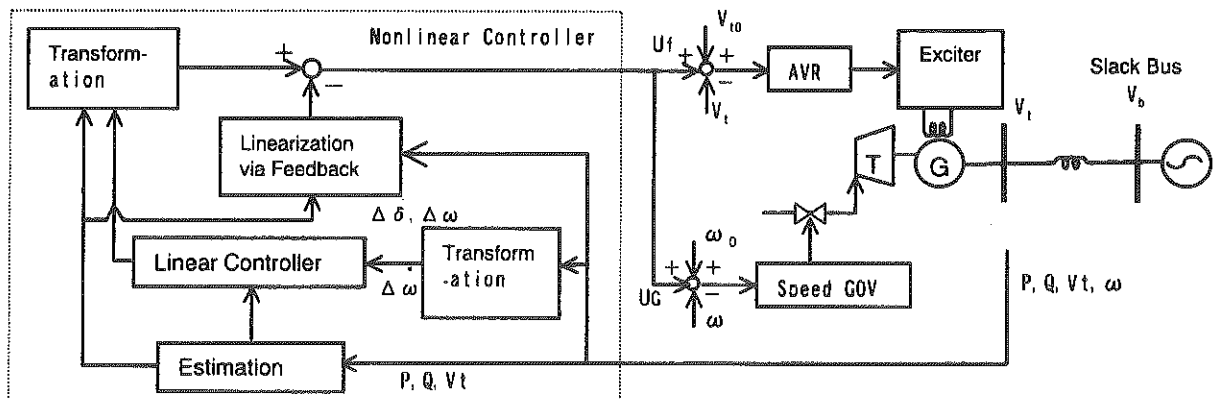


Fig.5. Nonlinear control system configuration

and the output of the speed governor are required for linearization. For this reason, in the nonlinear controller, the simple AVR and GOV block shown in Fig. 6 was modeled, and the output was used as the presumed value.

## 5.2 Evaluation by digital simulations

In order to evaluate the system stabilization effect applying nonlinear control, simulations were performed using the one machine-infinite bus model with load (Fig. 7). Fig. 7 shows the initial load flow when no control is applied. Fig. 8 shows the AVR block diagram and Fig. 9 shows the PSS block diagram. The stability problem arising from large-scale power system interconnections is low-frequency oscillation. Such low-frequency oscillation (about 0.16Hz to 0.5Hz) can occur with a one machine-infinite bus model with load.

If the cycle period of power swing is about 6 seconds, the nonlinear operation domain can become long, and there is a possibility that the conventional  $(\Delta P + \Delta \omega)$ -PSS has a small effect on damping power swing. Then, the following three cases were examined for transmission line 3LG-O failure.

- Case 1: Stability limit without auxiliary generator control
- Case 2: Stability limit with conventional  $(\Delta P + \Delta \omega)$ -PSS
- Case 3: Stability limit with nonlinear control

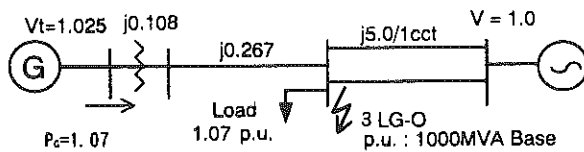
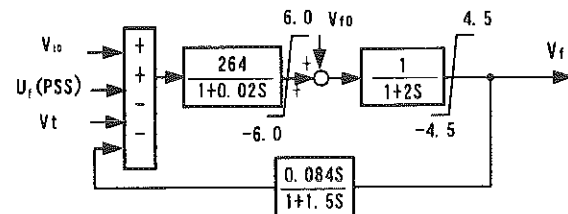


Fig. 7. One machine-infinite bus model with load



U : Output of Nonlinear Control  
PSS : Output of PSS

Fig. 8. AVR block diagram

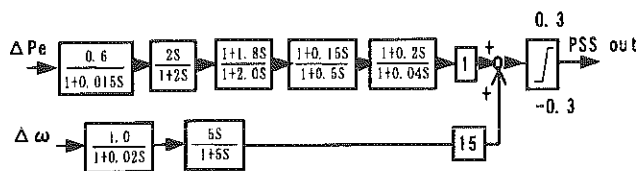
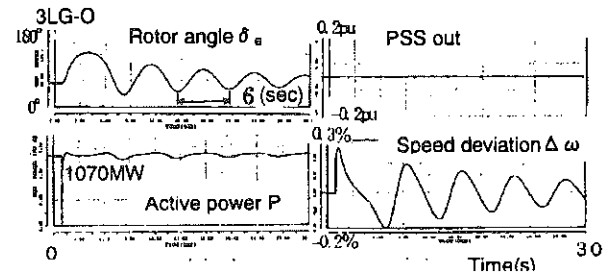


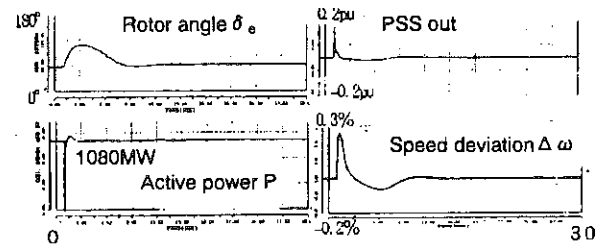
Fig. 9.  $(\Delta P + \Delta \omega)$ -input type PSS

The waveforms of the internal rotor angle, generator active power, rotor speed deviation and control output are shown in Fig. 10. The stability limit without auxiliary generator control is 1070 MW. The stability limit with conventional  $(\Delta P + \Delta \omega)$ -PSS is 1080 MW. The stability limit with nonlinear control is 1120 MW, and the limit of nonlinear control is larger than the conventional  $(\Delta P + \Delta \omega)$ -PSS by about 4%. If the internal rotor angle becomes

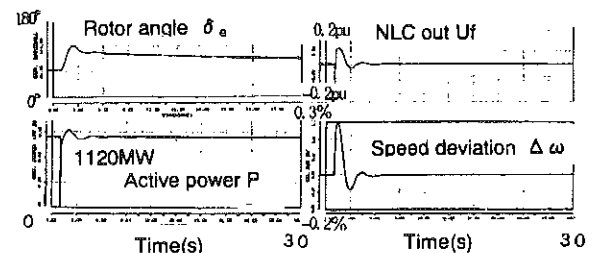
about 80 degrees or more after failure, the nonlinear characteristics of the power system become strong. In such a case, the nonlinear control has a larger effect than the conventional  $(\Delta P + \Delta \omega)$ -PSS.



Case 1: Without auxiliary control



Case 2: With conventional  $(\Delta P + \Delta \omega)$ -PSS



Case 3: With nonlinear control

Fig. 10. Digital simulation results

## 5.3 Evaluation by simulator tests

Fig. 11 shows the construction of the simulator. The generator and power system were modeled by the real time digital simulator (RTDS). After checking control block operation in digital analysis, the dynamic characteristics of the controller, modeled as a block diagram, was automatically changed and compiled for C code generation with the graphic user interface type engineering tool (MATLAB/SIMULINK), and mounted in the digital signal processor (DSP).

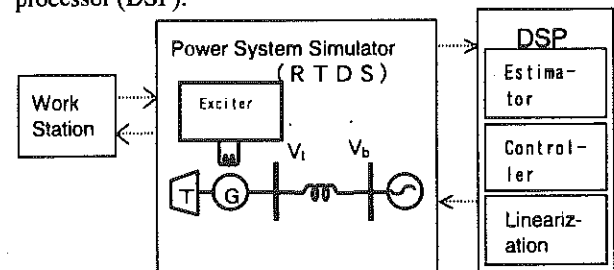


Fig. 11. Construction of simulator

The calculation time for the nonlinear controller is about 2ms on the pre-production DSP. The waveforms in the digital simulator are distorted by the noise, sample and hold etc. For this reason, by only calculating a rate of change for every sampling period, the calculation error becomes large and the system will be unstable. Then, a differentiation operation was devised as follows. The present value and the sample value of the 4 past times are used to calculate a rate of change by the least squares method.

The rate of change  $R$  is written by the following expression(26).

$$R = \frac{20 \cdot S_{g0} + 10 \cdot S_{g1} - 10 \cdot S_{g3} - 20 \cdot S_{g4}}{dt} \cdot \frac{1}{100} \quad (26)$$

$S_{g0}$ : Present sample value

$S_{g1}$ : First past times sample value

$S_{g3}$ : Third past times sample value

$S_{g4}$ : Fourth past times sample value

$dt$ : Calculation time

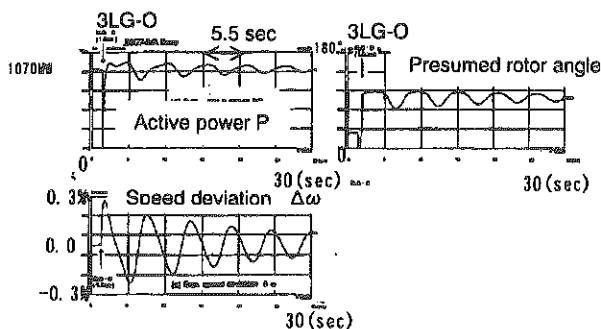
In order to evaluate the system stabilization effect when applying the nonlinear controller, simulations were performed using one machine-infinite bus model with load shown in Fig. 7. The simulator tests were performed under the initial load flow condition in a digital simulation. Then, the following three cases were examined for transmission line 3LG-O failure.

Case 1: Stability limit without auxiliary generator control

Case 2: Stability limit with conventional  $(\Delta P + \Delta \omega)$ -PSS

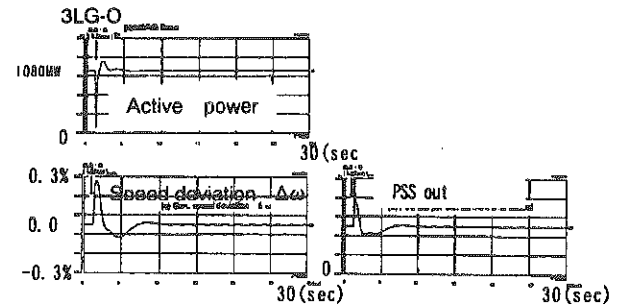
Case 3: Stability limit with nonlinear control

The waveforms of generator active power, rotor speed deviation, internal rotor angle and control output are shown in Fig. 12. The stability limit without auxiliary generator control is 1070 MW. The stability limit with conventional  $(\Delta P + \Delta \omega)$ -PSS is 1080 MW. The stability limit with nonlinear control is 1070 MW. Although the power swing continues for a long time without auxiliary generator control, the power swing at the stability limit is mitigated immediately with nonlinear control. The effect of nonlinear control is not as notable as seen for digital analysis. The conditions of simulator tests need to be checked and evaluated quantitatively.

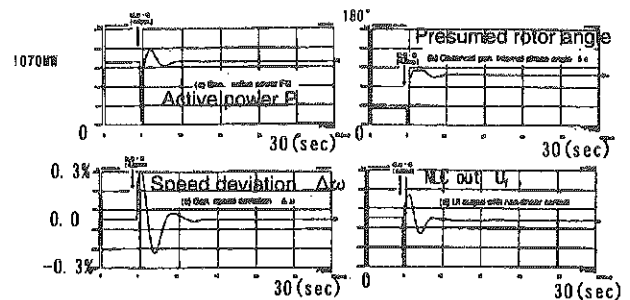


Case 1: Without auxiliary generator control

Fig.12a Simulator test results



Case 2: With conventional  $(\Delta P + \Delta \omega)$ -PSS



Case 3: With nonlinear control

Fig.12b Simulator test results

## 6. Future work

The effect of nonlinear control could be checked by digital simulations. The performance of a nonlinear controller will now be verified further using the multi-machine power system model. Moreover, the control system of FACT apparatus is built using nonlinear control theory. This research was performed under the international joint research grant of NEDO.

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## Appendix 1 Estimation of system information values

In Fig.1.1 the following equation is given.

$$\begin{aligned} \dot{I}_g &= (\dot{V}_1 - \dot{V}_2) \dot{Y}_{12} \\ \dot{Y}_{12}(\dot{V}_1 - \dot{V}_2) &= (\dot{V}_2 - \dot{V}_b) \dot{Y}_{23} + \dot{Y}_{22} \dot{V}_2 \end{aligned} \quad (1.1)$$

The equation (1.1) is transformed to the following equation by eliminating the voltage  $V_2$ .

$$\dot{I}_g = \frac{\dot{Y}_{12}(\dot{Y}_{22} + \dot{Y}_{23})}{\dot{Y}_{12} + \dot{Y}_{22} + \dot{Y}_{23}} \left( \dot{V}_1 - \frac{\dot{Y}_{23}}{\dot{Y}_{22} + \dot{Y}_{23}} \dot{V}_b \right) \quad (1.2)$$

From equation (1.2), the one machine-infinite bus model is obtained. Fig. 1.2 shows the one machine-infinite bus model. Fig.1.3 shows a transformation example.

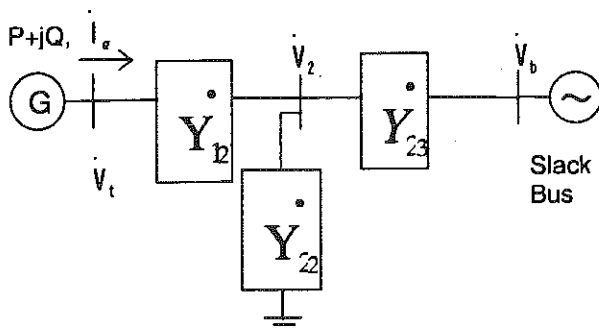


Fig. 1.1 One machine-infinite bus model with load

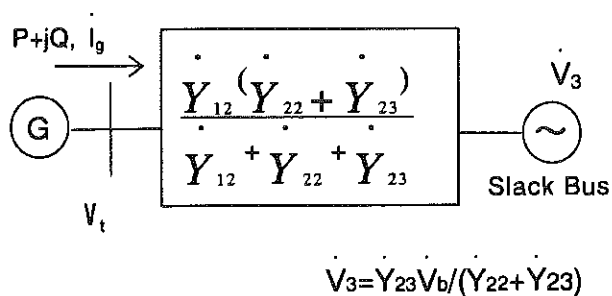


Fig. 1.2 One machine-infinite bus model

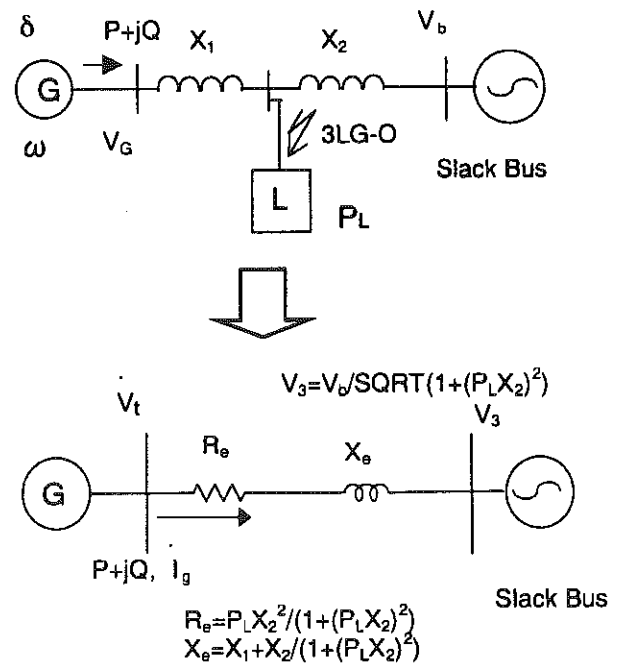


Fig. 1.3 Transformation to one machine-infinite bus model

## Appendix 2 Generator constants

Table 2.1 Generator constants

|                             | Generator G1 | Generator G2 |
|-----------------------------|--------------|--------------|
| xd [p.u.]                   | 1.569        | 1.651        |
| xd' [p.u.]                  | 0.324        | 0.232        |
| xd'' [p.u.]                 | 0.249        | 0.171        |
| xq [p.u.]                   | 1.548        | 1.590        |
| xq' [p.u.]                  | 0.918        | 0.380        |
| xq'' [p.u.]                 | 0.248        | 0.171        |
| xl [p.u.]                   | 0.204        | 0.102        |
| Td0' [s]                    | 5.140        | 5.900        |
| Td0'' [s]                   | 0.0437       | 0.033        |
| Tq0' [s]                    | 0.500        | 0.535        |
| Tq0'' [s]                   | 0.070        | 0.078        |
| D [p.u.]                    | 2.000        | 2.000        |
| $\omega_0 = 2\pi f$ [rad/s] | $120\pi$     | $120\pi$     |
| H [MW-Sec/MVA]              | 50.00        | 9.00         |
| Capacity [GVA]              | 6000         | 2            |

## The Hierarchical Voltage Control to face market uncertainties

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### Summary

The paper deals with the operating advantages coming from the possible implementation of a Hierarchical Voltage Control (HVC) for the transmission network voltages in the new deregulated environment.

At present, even if the need of a voltage regulation feature to ensure the security of a power system operation is largely recognized, the structure unbundling of modern electric systems may be considered as a challenge for the development of an integrated system for voltage levels and reactive power flows control. However, the paper is aimed at showing that a centralized grid voltage control, as well as the related improvement of the operation security, are of interest for all the participants to the electric market: it should be therefore implemented as a part of the ancillary services market, mainly concerning voltage quality and security.

The paper is aimed also at demonstrating how the presence of the hierarchical automatic voltage control, designed in the past by ENEL and recently taken over by the Italian ISO (GRTN), is still helpful in maintaining the security level and in facing the uncertainties of the electric system scenarios given by the market, that will be higher than in the past. Such a conclusion is supported by a complete and detailed analysis of several operating points of the Italian system, derived by the reports of the on-line state estimation.

### 1. Introduction

The common trend to the market in modern power systems is progressively resulting in the change of operation practices, which are more and more adapted to accomplish economic requirements. At the same time, technical requirements have to be in some way arranged, so as not to prevent the full application of the market rules. This allows the power systems operation more and more close to the maximum loading point but results in coordination problems of the various participants to the energy market [1].

However, the grid operation security needs a growing level of coordination among the power system resources (transmission grid and generating units), in order to avoid conflicting control actions and to properly act toward a common goal. This can be achieved in a market model by the ancillary services definition, where the Independent System Operator (ISO) can require or buy the participation of some Independent Power Producers (IPP) to the particular grid service of interest.

In any case, the ISO has to provide the service of coordination, in order to maintain the security level which is one of its duties. The security can be maintained by means of different control actions, more or less automatic, whose level of technology and performance does also contribute to determine the overall quality and economy of the grid operation practice.

In Italy, the former monopolist ENEL and more recently the national ISO (GRTN), designed and implemented a centralized and coordinated grid voltage control solution.

This paper deals with the performance of such a Hierarchical Voltage Control (HVC), applied to the Italian electric transmission system, in relation with the current development of the electricity market in Italy, which introduces new operation uncertainties to be faced.

The Italian HVC is based on three control levels [2][3]. The first level is represented by the well known primary Automatic Voltage Regulation (AVR), that provides the local support to the grid voltage profile. The second level is given by the Secondary Voltage Regulation (SVR): its aim is to coordinate the reactive power production in each area, by controlling the voltage at particularly high short-circuit level buses, named pilot buses; each generator controlling a pilot bus voltage acts in such a way that its reactive production is automatically balanced with the reactive production of the other controlling generators of the same area. The third level is the Tertiary Voltage Regulation (TVR): it defines in real time the most appropriate set points for the pilot buses, on the basis of the real system state and of the optimal voltage profile determined off-line, by the short-term reactive power dispatching, or also on-line, by the very short-term reactive rescheduling [4][5][6].

The HVC solution aims at improving the security margins and at obtaining a better voltage profile in the system, with an adequate distribution of the reactive resources in the different areas: this allows the system to face possible perturbations caused by contingencies or by significant displacements of the loads from the expected values. The HVC structure exploits the possibility to reach the above mentioned goals by means of a low number of signals and controls, requiring therefore a reduced amount of investments necessary.

The SVR is being implemented in Italy since 1998 [7][8][9] and its complete scheme is presently based on 18 control areas and pilot buses, with about 46 regulating power stations and 200 controlling generating units. The highest hierarchical level of TVR is scheduled to be put in service within 2002.

The paper is focused on the demonstration that the adoption of the HVC, originally designed for the management of the previously vertically integrated Italian system, is compatible with the new structures of the electric industry and market. Moreover, the performance of the power system operation, attainable by the adoption of SVR and TVR, better than the simple local control demanded to the AVR, is demonstrated also in the new environment.

The results presented refer to the analysis and simulation of several cases of real operation from 1998 to 2000 relevant to the overall Italian transmission system in its interconnected operation with the UCTE system. The system state estimations studied refer to a grid of about 1300 buses and are relevant to the both HV and EHV networks.

## 2. The hierarchical voltage control

The ENEL project taken over by the Italian ISO (GRTN) is based on a hierarchical control structure (see figure 1) which provides a network subdivision into electric areas around the so-called pilot nodes, which are grid busses selected on the basis of the short-circuit level and some sensitivity computation criteria.

The pilot nodes are chosen based on their short circuit capacity, i.e. the nodes with the largest short circuit ratio in a given region are chosen as the pilot nodes. The generators that control each pilot node are then chosen through a sensitivity analysis of the pilot node voltages with respect to the generating units outputs: the largest inputs on the sensitivity matrix define the most suitable generators that should be associated with the pilot nodes.

In the SVR framework, each pilot node voltage is controlled in real time at a desired set point by means of signals of "reactive power level" of the pertinent area provided by the Regional Voltage Regulators (RVR). The reactive voltage level represents the reactive power that should be produced by the controlling generators of the area in order to maintain the pilot node voltages at the desired values. The controlling generators of each area are chosen among generators which most influence the pilot node voltage. The generator control is locally achieved at power plants by means of Reactive Power Regulators (PQR), directly acting on the Automatic Voltage Regulators (AVR) of the generating units.

In the TVR framework the National Voltage Regulator (NVR), at the national/utility level, controls in closed loop the RVRs for a secure and economic operation, establishing the "pilot node voltage" pattern, according to the actual network state and to the long, short or very short-term forecasting of the pilot node optimal voltages and of reactive levels.

By means of the coordination between the SVR and TVR, it is possible to operate in security the transmission network very close to the highest voltage limits, through the real-time control of the main generators which are automatically forced to their limits only when needed, satisfying high requirements of functionality and reliability related also to market uncertainties.

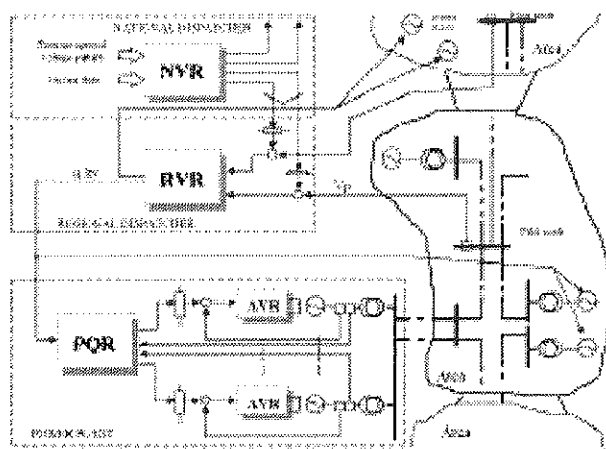


Fig. 1 - Schematic diagram of the Italian hierarchical SVR and TVR system.

The detailed design and development of the TVR is currently being carried out, while the application plan of the SVR is on the way to be finished with very satisfactory results. Both of them required the knowledge of power system needs and the design and practical realization of very specialized control devices, which had to take into account also of the present evolution of control technology, the growing automation level required and the effective and friendly interfaces asked by control room operators.

The overall SVR application plan involves all the major power plants connected with both the 380 kV and 220 kV network, for a total reactive power capacity of about 18,000 Mvar. Currently, the Italian SVR project is in partial operation: in October 1998 the first area in the Lombardy region has been set under the RVR of Milan, with the pilot bus of S.Rocco (or alternatively Baggio) and only the Piacenza thermal power plant controlling the pilot bus voltage; in September 1999 other power stations (Turbigo, La Casella, Tavazzano) became into the same SVR controlling set. In June and December 2000 two areas have been further set in the Campania region, under the RVR of Naples: the hydro plant of Presenzano is currently controlling the S.Sofia pilot node, while the thermal power plant of Rossano Calabro is controlling the related pilot bus.

The figure 2 depicts the complete diagram of the SVR pilot nodes and control areas for the overall Italian transmission system, as foreseen by the present GRTN application plan.

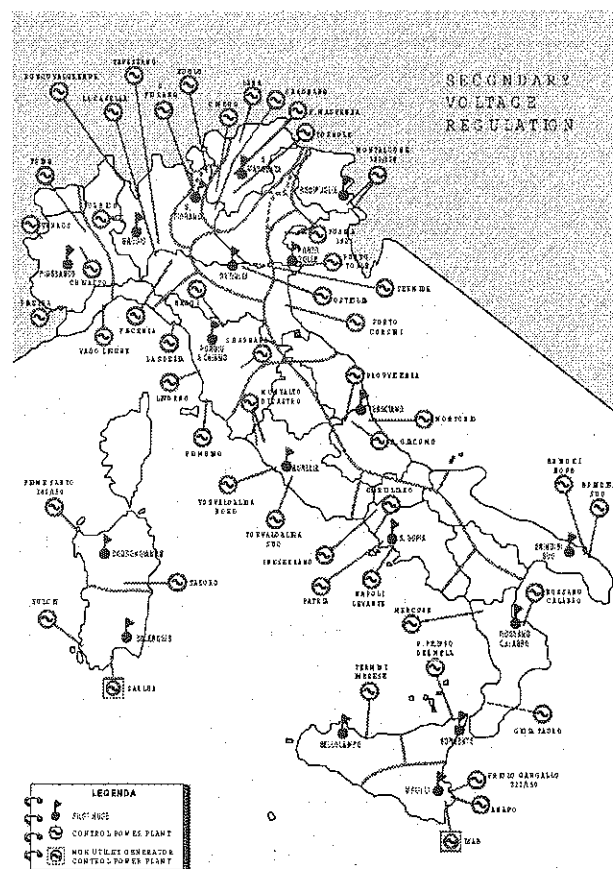


Fig. 2 - Outline of the Secondary Voltage Regulation.



### 3. The methodology adopted

In order to demonstrate how the centralized HVC can be of interest also in a deregulated environment, its performances have been monitored and resumed following a methodology detailed in this section. The results of the research make use of some performance indicators, which take into account the real losses in the transmission system, the global margin of reactive power at disposal of the generation units, the distribution of the reactive power in the different areas, the attainment of operational constraints. Once suitable metrics are defined, a procedure to compare the performances of the system with the HVC in full operation, with the HVC in its present partial operation or with only the primary control is presented [10].

#### 3.1 The considered scenarios

The first scenario considered (called **SE**) is given by the state estimation program reports at the GRTN Control Center. They give the actual state of the power system at a selected time horizon. The studied scenarios result from the methodology that GRTN is planning to employ for scheduling the AVR set points. The AVR reference values are determined by a reactive OPF program, running the day before for the next day on the basis of the short-term load forecast. This procedure results in an operating point that is sub-optimal, due to the difference between the forecasted and the actual load. Moreover, often the system operator does not adopt fully the voltage set points resulting from the OPF, preferring to set some voltages or some reactive power levels based more on his practical experience than on a mathematical optimization procedure, so taking into account other objective functions in something like an empirical multi-objective optimization framework [11].

As a first step, in order to evaluate the performances of the HVC, the same situations are then studied by using a Reactive Optimal Power Flow (ROPF) in order to determine the optimum point, starting from the state estimation operating point. The ROPF adopted makes use of the Han-Powell second order procedure to determine the best generator voltage set point (AVR) profile in order to minimize the total transmission losses of the system [12]. The point determined (called **UO**) is relevant to the optimization of the global system, Italy plus UCTE, considering the voltage constraints on the most important busses (sentinel busses) and the constraints given by the capability charts of generators. Of course, this optimum point calculated taking into account losses only, is not aimed at improving the security level at all.

A second ROPF solution point (called **SVR**) is obtained taking into account the SVR additional constraints, i.e. the constraints relevant to the pilot bus voltage and the "alignment" reactive power production constraints of the controlling generators, for each area. In this second case, given that the number of constraints is higher than in the previous case, and given that the controlling generators are not free to set independently their AVR reference values, the losses are higher.

An intermediate point (called **SVRL**) is given, for each scenario considered, by the partial introduction of the SVR in the only Lombardy region, as in the actual system in operation since 1998. Thus, a third ROPF run is performed with the SVR in operation only in the area with pilot node S.Rocco.

#### 3.2 The computed metrics

For the three situations above described, a set of indices is evaluated, in order to highlight the performances of the HVC. The indices are chosen among the possible metrics in order to compare the performances in terms of efficiency, quality and security of the power system.

The following indices are considered:

1. mean value of the pilot bus voltages calculated in pu:

$$MV = \frac{\sum_{i \in P} \frac{V_i}{V_{ir}}}{N_P}$$

where  $P$  is the set of the pilot nodes,  $V_i$  is the voltage of the  $i$ -th bus,  $V_{ir}$  is the rated voltage of the  $i$ -th bus,  $N_P$  is the number of the pilot nodes considered; of course, in all cases, the busses considered are the same, but actually they are pilot busses only in presence of HVC.

2. losses on the transmission system  $L$  (in pu of the total load);

3. reactive power margins of generators for each area  $k$ :

$$MQ_k = \sum_{i \in A_k} (Q_{gi \max} - Q_{gi})$$

where  $A_k$  is the  $k$ -th area,  $Q_{gi \max}$  is the maximum value of the reactive power of generator  $i$  and  $Q_{gi}$  is its actual reactive power generated;

4. violation of voltage constraints at sentinel busses:

$$VV = \sum_{i \in S} \frac{|\Delta V_i|}{V_{ir}}$$

where  $S$  is the set of operating voltage constraints violated,  $|\Delta V|$  is the absolute value of the violation. Actually, voltage violations have been subdivided into 400 kV violations ( $VV_{400}$ ) and 230 kV violations ( $VV_{230}$ ), that can be considered less important from the security point of view. The sentinel busses are defined by the experience of the system operators as the busses particularly representative of the area voltage profile.

Index 1 is related to the quality of service and to the security level; index 2 is relevant to the efficiency of the system; indices 3 and 4 can give an idea of the security level of the current network operating point.

The above indices have been recorded for each situation and for each optimized point in order to evaluate the impact of the different control schemes and of the different degrees of application of the HVC.

#### 3.3 The simulation of market uncertainty

A second set of tests has been carried out, related more in detail to the ability of the HVC, which is an automatic voltage control, of facing the possible situations given by the market, and in particular the uncertainties between the active and reactive load forecasting and the actual values.

At present, it is easy to predict that the complete functionality of the market (forecasted for the year 2002) will result in a greater uncertainty on the load and generation profile and on the grid topology; thus, for the GRTN will be more and more difficult to ensure the security of the system by managing the ancillary services such as the reactive control.

A major difference with respect to the past is that the planned operating procedure of the GRTN, consisting in the definition of the AVR set points based on the situation forecasted the day before, can be overcome by the fact that the forecasted situation can result significantly different from the actual operating point due, for example, to the greater volatility of the electricity market price.

The methodology here considered aims at simulating what will be the impact of the automatic voltage control in presence of the market, in order to evaluate whether the HVC can help the GRTN in managing conditions perturbed with respect to those forecasted, or even critical conditions. Based on the load forecast available the day before, the evolution of the system in such a scenario can be simulated in presence of the HVC, in particular with the SVR in operation. The effect of the HVC is evaluated by means of the comparison between two situations determined as described in the following:

1. the **case UO** corresponds to the optimization run on the forecasted scenario without SVR, in order to calculate the best AVR set-point voltages for the next day;
2. the **case SVR** corresponds to the optimization run on the forecasted scenario with SVR: the best AVR and pilot bus reference voltages are calculated for the next day;
3. the **case PF1** actual scenario is the one resulting by the state estimation, where the loads are, in general, different from the forecasted ones and the AVR set points are resulting by the optimization output determined as in the point 1, corrected by the operator on the basis of his experience and on the on-line requirements of the system;
4. the **case PF2** scenario is the result of the power flow computation resulting by the simulation of the power system where the loads are retrieved by the state estimation (case PF1) but the AVR set points given by the optimization output determined without SVR as in the point 1 are imposed at generator terminals;
5. the **case PF3** scenario is the result of the constrained power flow computation resulting by the simulation of the power system where the loads are retrieved by the state estimation (case PF1) but the AVR set points and the pilot bus set points are defined according to the optimization output determined with SVR as in the point 2.

The metrics defined in the previous subsection are calculated for each situation and allow the comparison of the performances of the power system in full and partial presence or in absence of the HVC.

#### 4. Tests and results

The tests for the evaluation of the impact of the HVC are based on the scenarios coming from the state estimation of the GRTN on-line control system. The data are relevant to the HV and EHV Italian power system (380 and 220 kV) in its interconnected operation with the UCTE system, represented by an equivalent system. The Italian system is made up by approximately 1350 busses, 45 thermal generators and 150 hydro generators.

Due to the on-going practical implementation of the HVC, the SVR is not in operation until 1998, and in the state estimation cases since 1998, the SVR is actually present only in a limited (although very important) area of the power system.

For the study, 34 cases have been considered (19 for morning peak load hours, including a Sunday, 15 for night no load hours) selected among the most significant scenarios for the Italian system in the different time seasons. The load supplied directly at the 380/220 kV level is described in table 1 (just for reference, the total yearly peak load in the Italian system was about 46 GW, with imports of approximately 4.5 GW).

It is worth noticing that the load is growing during the years. On the contrary, due to environmental and bureaucratic reasons, it is more and more difficult to build new transmission facilities and therefore the transmission grid is going to become progressively more critically exploited. For this reason, also the efficiency of the HVC may result progressively limited, due to the reduced possibility to influence the network operation.

| Day      | HV load [GW] |          |
|----------|--------------|----------|
|          | 11.00 AM     | 03.00 AM |
| 27/01/98 | 28.334       | 15.093   |
| 28/01/98 | 28.540       | 15.211   |
| 18/03/98 | 25.841       |          |
| 22/04/98 | 23.413       |          |
| 20/05/98 | 23.500       | 13.354   |
| 17/06/98 | 26.001       |          |
| 12/07/98 |              | 13.646   |
| 19/08/98 | 19.296       |          |
| 27/01/99 | 29.284       | 15.718   |
| 18/03/99 | 26.224       | 14.788   |
| 22/04/99 | 25.901       | 13.560   |
| 23/06/99 | 26.249       |          |
| 22/09/99 | 25.552       |          |
| 21/10/99 | 27.728       | 15.093   |
| 15/12/99 | 29.038       |          |
| 16/12/99 | 28.646       |          |
| 27/01/00 |              | 16.675   |
| 19/04/00 | 27.437       | 15.584   |
| 10/05/00 | 26.740       | 14.393   |
| 17/05/00 | 26.418       | 14.887   |
| 21/06/00 |              | 16.184   |
| 20/09/00 |              | 18.451   |

Tab.1 - Scenarios considered for the case study.

The first tests are relevant to the comparison of the results of different types of optimization applied to the scenarios coming from the state estimation, according to the procedure described in section 3.1. In particular such a comparison is made based on the metrics defined in section 3.2.

The first metric considered is MV. In figure 3 the different behavior for cases SE, UO, SVR, SVRL is shown, for the scenarios relevant to the peak load hours (11.00 AM). The most evident result is that the mean value of voltage levels at the considered busses (that are actually pilot busses only when SVR is considered) can be very different, and in particular higher, in presence of any optimization procedure. The difference among the optimized and the non optimized cases is about 6% of the rated bus voltage.

The second index considered is given by the total losses of the system, in percent of the total load. In figure 4, the losses of the system are shown for the no load hours (03.00 AM) cases studied. For those cases, also, the voltage profiles obtained in cases with SVR are quite higher than without it, but losses are not quite different. In the peak hours scenarios, the optimization allows operating points with a slightly improved losses, although the improvements are not quite significant.

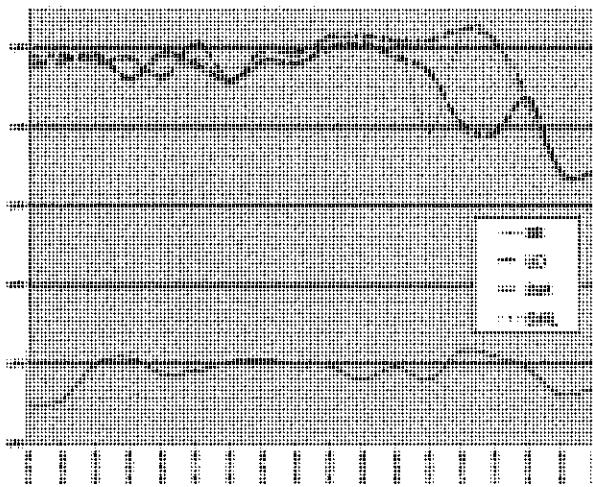


Fig.3 - Index MV for the peak load hours.

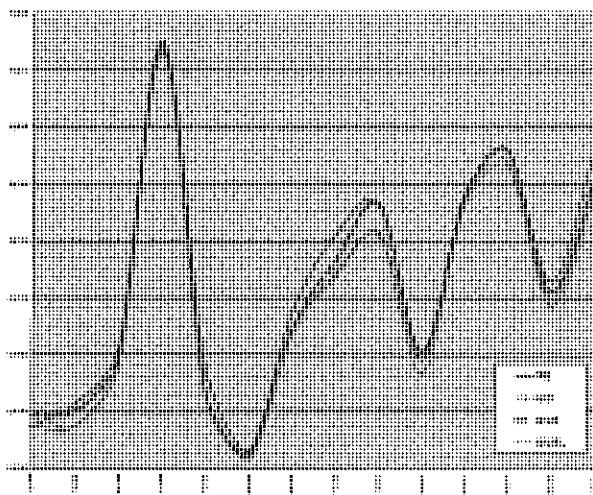


Fig.4 - System losses for the no load hours.

Usually, the introduction of the alignment constraints in the SVR and SVRL cases, results in losses higher than in case UO. At this regard it has to be pointed out that the HVC is not mainly aimed at reducing the system losses, but at improving the security margins at disposal of the system operator.

Another interesting issue is the consideration that, as the load increases (from 1998 to 2000 the total load increases of about 8%), the capability of the voltage control to coordinate voltage resources is progressively limited. This can be seen in figure 5, where the linear trend (determined by a linear regression technique) of the percent losses calculated for the system is depicted, using the UO cases as base cases. At present, because the reinforcements of the transmission system are more and more difficult to be realized, the transmission grid is more and more "saturated" and the coordinated voltage control system as well as any type of optimization have less and less freedom degrees and thus can result less effective. This is the reason why the trend of the losses is converging to the SE trend.

The last index considered is relevant to the violation of voltage constraints. Some particularly critical busses experience, called sentinel busses, have been identified, based on the system operator. Index VV is computed for the voltage violations at these busses, and it is represented in figure 6: in general, the voltage violations can be considered negligible in all the studied situations.

The better coordination of the reactive resources of each area can be observed from figure 7, where the reactive production of the Piosasco area generators is shown for the peak load hours, in percent with respect to the total reactive power that can be produced in that area. The interesting aspect is that the SE cases usually are characterized by a high level of reactive power production (and therefore by reduced margins), while the SVR cases are in an intermediate position between the SE and the UO cases. The conclusion is that the SVR can give, automatically, a security level comparable to the security level that could be obtained by optimizing on-line the power system.

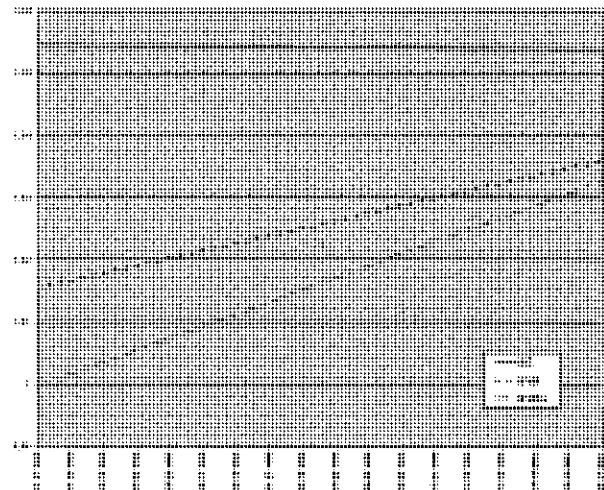


Fig.5 - Linear trend of losses in peak load hours.

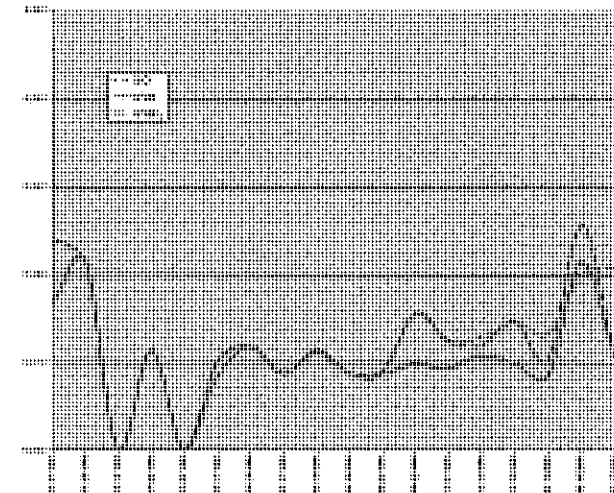


Fig.6 - Voltage violations in peak load hours.

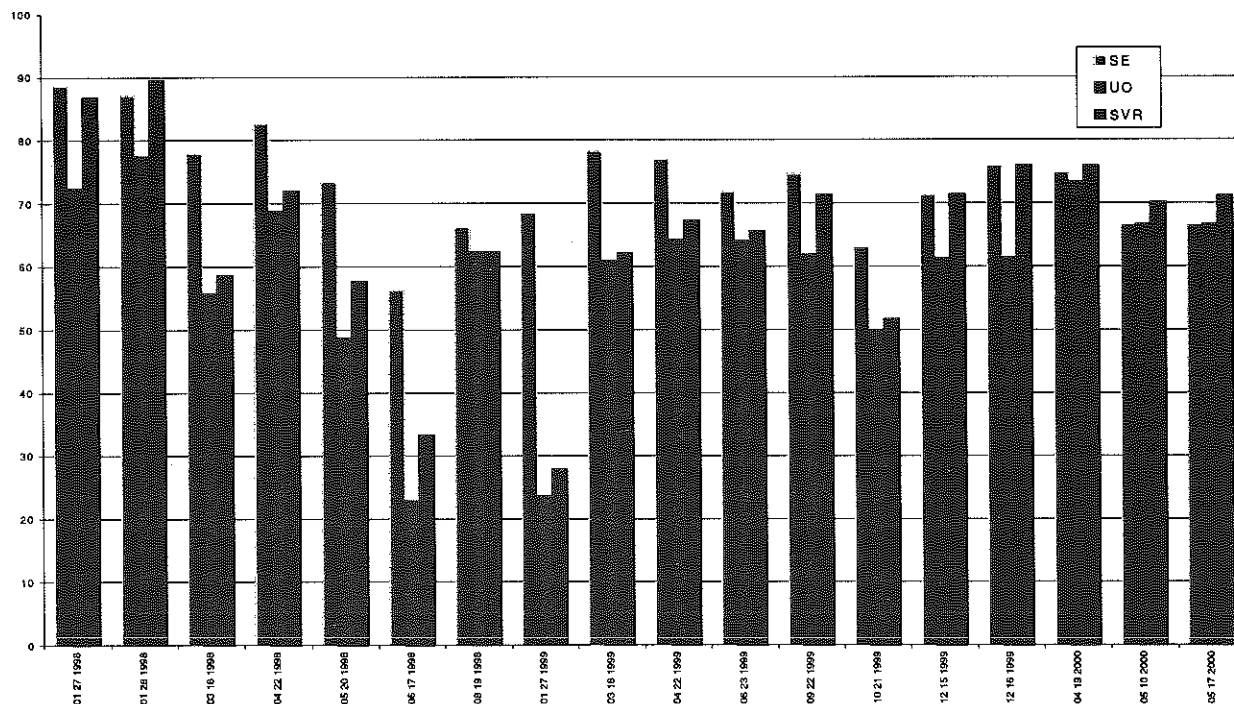


Fig.7 - Reactive power margins of the Piosasco area.

A second set of tests deals with the robustness of the HVC against possible deviations from the forecasted scenario. This particular aspect is actually critical not only in presence of market forces, but it is going to become more and more important due to the volatility of prices that can increase the uncertainty level of the load and generation scenario. Thus, for the system operator it will be difficult to face correctly the uncertainties; therefore, the HVC can become a very efficient automatic tool to help the system operator.

The difference between the forecasted scenario and the actual load and generation profile can be quantified for the considered network situations in about 200 MW.

The figure 8, relevant to the index MV defined in section 3.2, shows this error impact on the voltage control procedure. With reference to the notation adopted in section 3.3, cases UO, SVR, PF1, PF2 and PF3 results are shown.

The interesting comment is that, adopting the reactive dispatch settings corrected by the system operator (case PF1) does not result in a performance as good as the behavior given by any automatic voltage control (case PF2 and case PF3). The comparison among these three cases shows that the adoption of the set points given by the optimization procedures applied to the forecasted scenario result in mean voltage levels higher than those resulting from the practice of the system operators.

In particular, the presence of the SVR allows the operation of the power system at a mean voltage level significantly higher than the other cases. This circumstance is basically allowed by the automatic level of coordination made available by the HVC, which is capable to regulate the pilot node voltage fully exploiting the reactive power capability on the controlled units. Moreover, the difference between cases UO and PF2 compared with the difference between cases SVR and PF3 shows that the

performance degradation due to the load forecasting errors is more significant without coordinated control than in presence of SVR; the power system operation is therefore more secure due to this higher level of control robustness.

The figure 9 deals with the losses in the power system. The results shown are relevant to the same five cases UO, SVR, PF1, PF2 and PF3 defined in section 3.3.

This figure confirms that the automatic voltage control can make more robust and efficient the power system against grid perturbations or errors in the forecasted scenario. The lower loss level of the PF2 and PF3 cases compared with the PF1 case shows that the power system is less sensitive in presence of HVC and can be operated in a more efficient and secure way, reducing losses and facing unexpected situations.

A more in-depth analysis is allowed by the comparison between the above mentioned data and the other two columns. UO and SVR represent a benchmark of the behavior of the automatic voltage control. They are relevant to the actual load scenario optimized without and with the SVR respectively: they can simulate a zero error forecasting procedure, that is the best performance that can be obtained given the actual load level. The comparison between PF2 and UO shows that the optimization in absence of SVR could improve significantly the voltage profile. This can be explained both by the error in the load forecast procedure and in a low robustness level of the primary voltage control. On the contrary, the second comparison, between PF3 and SVR, shows that the robustness of the HVC is very important: given the same error in the load forecast procedure, the HVC can face in a quite better way the unexpected load level, resulting in performance that operates the power system at a point where the loss level is the best that can be achieved (equal to the benchmark).

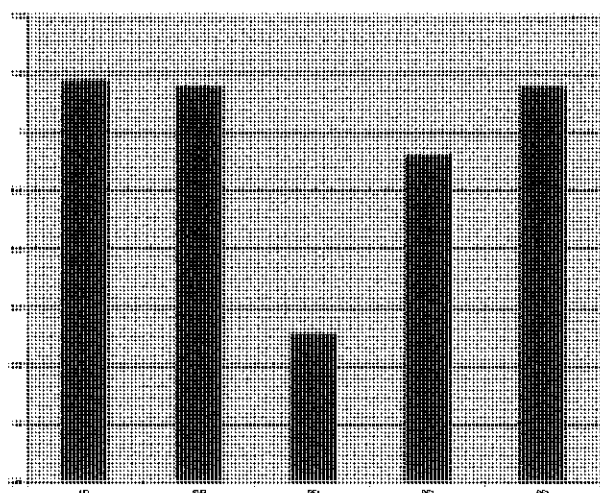


Fig.8 – HVC effect on the index MV of the transmission system.

## 5. Conclusions

The paper demonstrates that the positive impact of the presence of a Hierarchical Voltage Control in presence of increased uncertainty levels given by the electricity market. Actually, the HVC provides an operating point which is more robust than the situation without the HVC, against perturbations such as load forecast errors or contingencies. The robustness given by the HVC is very important in presence of an electricity market where, due to economic strategies that can be very different from technical strategies, it is more and more difficult to forecast accurately which generators will produce or will be not committed, due to their bids out of the merit order. The presence of a higher level of insensitivity to these market uncertainties increases the overall reliability of the electric system and therefore represents a strong incentive to actuate a centralized form of voltage control, even in presence of a market pushing to a decentralized form of grid operation.

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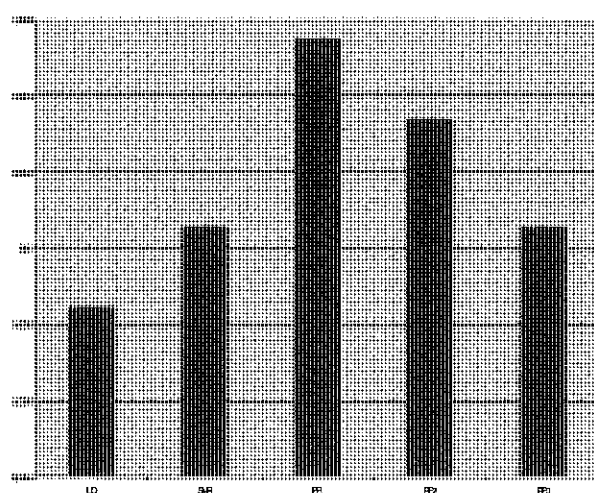


Fig.9 - HVC effect on the losses of the transmission system.

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## Evaluation of load margins with respect to voltage collapse in presence of Secondary and Tertiary Voltage Regulation

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### Summary

The paper deals with a static and dynamic evaluation of the load margins, with respect to the voltage instability and collapse phenomena, of a power system with different network voltage control configurations, in particular in presence of a coordinated voltage control of the transmission grid based on Secondary and Tertiary Voltage Regulations (SVR and TVR). This automatic control system allows an effective coordination of the reactive power resources, mainly those of the generators, through a composite regulation structure, in order to keep up a suitable network voltage profile, facing continuously changing reactive power demands and possible grid perturbations.

As shown in the paper, with the presentation of examples pertinent to the Italian 400 kV network, the SVR and TVR control schemes originally proposed by ENEL and in an advanced application phase by the Italian ISO (GRTN) increase the load-ability of the transmission system and defer the occurrence of critical operating conditions with respect to the voltage instability or collapse risk. This expected result, which can be easily checked through suitable steady state approaches and transient simulations, could also be predicted with the help of both off-line and on-line suitable voltage stability indicators. The increase of the load margins of the transmission network is basically achieved by a proper coordination between the Regional and National Voltage Regulators (RVR and NVR), whose control actions try to avoid that the generating units are operated at their limits. If the reactive power regulation margins available for the SVR control become strongly reduced, as a consequence of severe perturbations or abnormal load pattern, the TVR attends the transmission network voltage reduction, progressively renouncing to the optimal day-ahead forecasted or short-term planned voltage profile. The coordination between TVR and SVR represents therefore a real chance for the grid operators, in order to achieve a full exploitation of the power transfer capabilities of transmission networks, requirement more and more important in the restructured and liberalized electric energy markets.

### 1. Introduction

The electrical utilities are progressively operating the networks as closer as possible to their maximum transmission capability. Moreover the increasing interconnection among grids of different sizes and characteristics makes the voltage control more and more critical, with increase of active and reactive power losses as well as of voltage instability and collapse risk.

The "voltage instability" phenomenon, usually due to a wide variety and combination of different grid operating conditions (high loads, system components failures, OLTCs reverse actions, generating units operation at over-excitation limits), initially arises with a gradual reduction of the transmission network voltages, which progressively becomes considerable and without recovery. The voltage profile decay, once it becomes irreversible, determines the terminal phenomenon of "voltage collapse", characterized by uncontrollable transient instability, with units breaking and protections intervention.

The voltage stability problem have recently largely drawn the attention of both researchers and operators for limiting system faults and related costs. This mainly because of the growing competition in the electricity market and the increased needs of improving system operation security and quality, reducing at the same time operational, maintenance and reliability costs. In particular, the precise evaluation of load margins, with respect to the voltage instability and collapse limit, has been largely investigated with high interest in recent literature, mainly for planning studies but also for network optimization, short-term operation up to real-time monitoring and control.

The growing need in some power systems of reactive power resources, for the transmission network voltages support, as well as the strong connection of this problem with voltage instability and collapse phenomena are further reasons of this enlarged interest. At this concern they have to be considered the growing difficulties for units reactive power control, mainly due to the perspective of a continuously changing scenario of the reactive resources availability, also because of the "voltage service" market and its recognition into the energy tariff. The above reasons are pushing the utilities in developing and applying the most suitable voltage control systems, adequate for an economic point of view and capable to deal with the evolution of load demands and possible system contingencies.

About the voltage instability and collapse problem the literature is very wide: excellent reports [1][2][3][4] include the description of basic phenomena, terms and definitions, modeling and simulation requirements, different kinds of voltage stability indices, various scenarios of incidents and an extensive list of references. Papers [5, 6, 7] show also the growing trend to study such a phenomena taking into account the overall power system dynamics, through detailed mathematical models inclusive of unit regulation and limitation loops, OLTCs and network voltage control loops (i.e. SVR and TVR). The modeling of these dynamic aspects contributes also to properly consider the non-linear effects, due for instance to the control loops limits and the system protections intervention.

Over the recent years a lot of examples and criteria for the evaluation of power system stability margins, with respect to the voltage instability and collapse phenomena, have been studied and proposed by the literature. Such evaluations have been often based on voltage stability indices [8][9], which generally give a measure of the margin between the current network operating point and the grid instability limit, thereby providing an early warning of a potential critical situation.

The load margins evaluation based on voltage stability indices mainly concerns the off-line preventive analysis, related to the system planning [10][11][12][13]. The evaluation usually needs system state condition, load-flows and algorithms falling within either the large-perturbations analysis or the small-variations analysis around a given steady-state condition, resulting often onerous, due to the iterative methods used for wide network models, Jacobian and sensitivity matrices, optimization, etc.

The literature gives also practical examples of instantaneous evaluation criteria, for the stability margins computation of the network operation point with respect to the voltage instability limit [14][15][16]. This kind of evaluation has to be based on real-time measurements of the state and control variables of the

network and has to be performed in a short time (few seconds) in comparison with the dynamic of the network voltage reduction process. In this framework an automatic network control and protective action could also be triggered on-line and in real-time with the goal to delay or avoid the attainment of unstable operating conditions.

At present, even if the need of a voltage regulation feature to ensure the security of a power system operation is largely recognized, the unbundling structure of the modern electric systems may be considered as a challenge for the development of an integrated system for voltages levels and reactive power flows control. However, a centralized grid voltage control, as well as the related improvement of the operation security, are of interest for all the participants to the electric market: it should be therefore implemented as a part of the ancillary services market, mainly concerning the voltage quality and security. The possibility to combine a voltage security assessment with a high quality and economic operation, depicts in fact a solution for advanced EHV network voltage control systems, which can be achieved through the modern very powerful digital technology and the support of high level software tools.

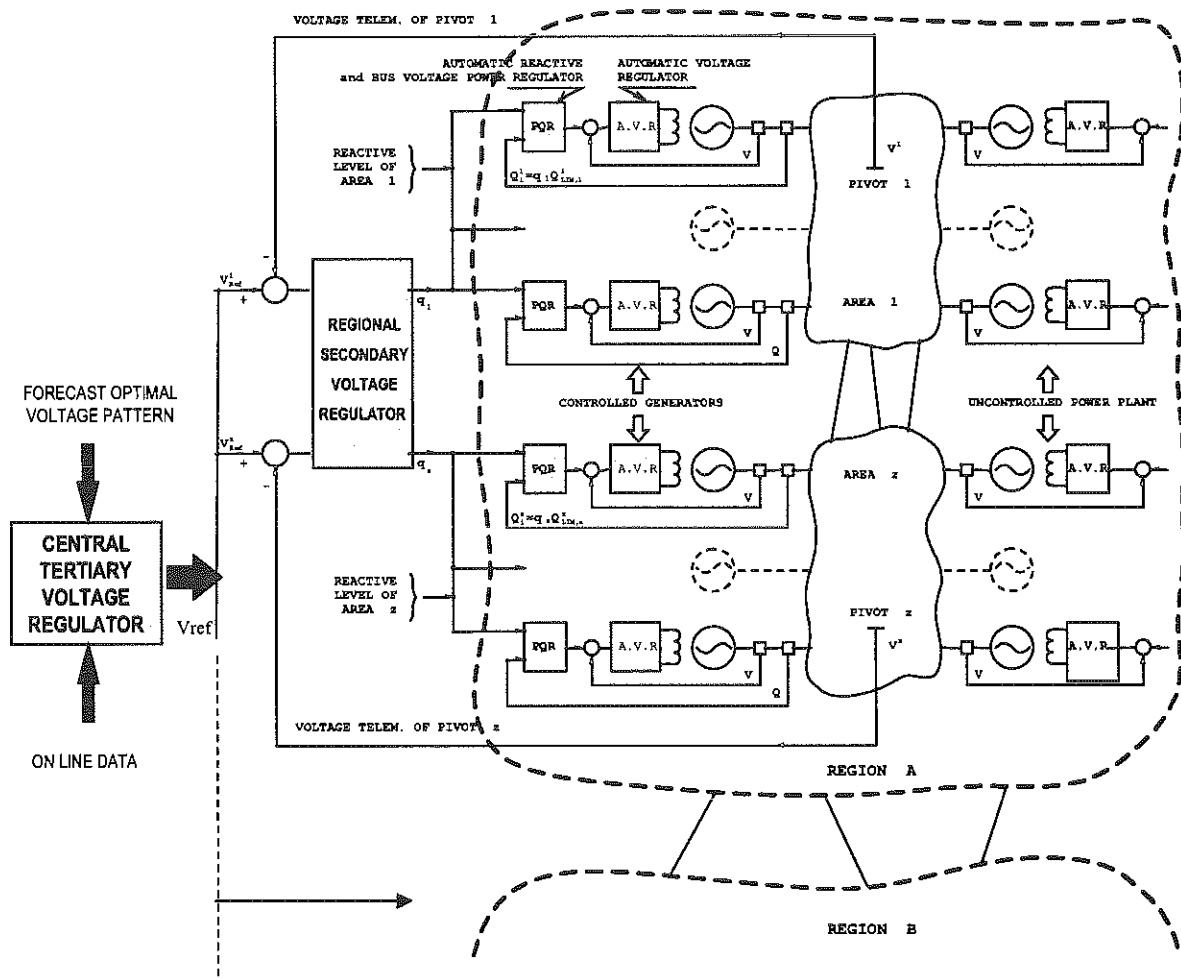


Fig.1 - Schematic diagram of the Italian hierarchical SVR and TVR system.



## 2. The Italian voltage control system

The ENEL project [17][18][19], recently taken over by the Italian ISO (GRTN), is based on a hierarchical control structure (see the figure 1). This provides network subdivision into electric areas around the so-called pilot nodes, which are grid busses selected from the strongest ones, on the basis of short-circuit powers and sensitivity matrices computation criteria. In the SVR framework these areas are controlled by suitable signals of “reactive power level”, one for each area, provided by the RVR apparatuses, which maintain the pilot nodes voltages at the desired values, through the real-time control of the reactive powers of those generators which most influence the pilot nodes busses. The generator control is locally achieved at the power plants by means of the Reactive Power Regulators (PQR), directly acting on the set-points of the Automatic Voltage Regulators (AVR) of the generating units. In the TVR framework the NVR, controls in closed-loop at the utility level the RVRs for a secure and economic operation, establishing the “pilot nodes voltages” pattern, according to the actual network state and the long or short-term forecasting of optimal pilot nodes voltages and areas reactive levels. By means of this hierarchical control system it is possible to operate in security the transmission network, very close to the highest voltage limits, through the real-time control of the main generators, which are automatically forced to their capability only when needed. The ENEL project for the SVR and TVR required the knowledge of power system needs and the design and practical realization of specialized control apparatuses, not available on the manufacturers market, developed by using of various electronic technologies [20][21][22]. The detailed design and development of the TVR is currently being carried out, while the application plan of the SVR is practically finished with very satisfactory results [23]. Taking into account the present evolution of control technology, the growing automation level required and the effective and friendly interfaces asked by the control room operators, it comes out that the PQR, RVR and NVR apparatuses must satisfy, today more than in the past, high requirements of functionality and reliability, for facing also market uncertainties [24].

### 2.1 Secondary Voltage Regulation (SVR)

The basic SVR structure of the Italian network subdivides at present the overall country into 18 areas for voltage regulation, chosen based on their geographical and systemic characteristics, i.e. location and network “density”. Each area has a pilot node, with its voltage controlled remotely by a RVR and a set of regional generators: the pilot nodes are chosen based on their short circuit capacity, i.e. those nodes with the largest short circuit ratio (SCR) in a given region are chosen as the pilot nodes. The generators that control each pilot node are then chosen using the sensitivity analysis of the pilot node voltages with respect to the generator reactive powers: the largest inputs on this matrix define the generators that should be associated with the pilot nodes.

The overall plan involves all the major power plants connected with both the 380 kV and 220 kV networks, for a total reactive power capacity of about 18,000 Mvar

The figure 2 shows the subdivision into areas of the Italian network, pointing out the nodes and the control power plants according to the SVR application plan.

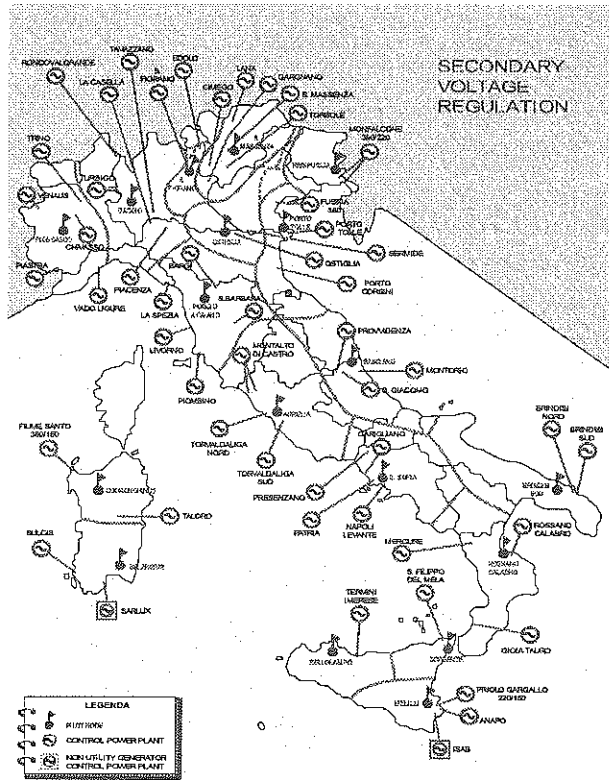


Fig.2 - Application plan of the SVR in the Italian grid.

### 2.2 Tertiary Voltage Regulation (TVR)

At the highest hierarchical level of TVR, the NVR, scheduled to enter in service within 2002, will define in real-time, for a secure and economic operation, the most appropriate voltage set-points of the pilot nodes, on the basis of the actual state of the network and the forecasted optimal voltages and area reactive powers, optimizing the Objective Function (OF):

$$OF = [V_p - V_{Pref}^0]^T \beta^2 [V_p - V_{Pref}^0] + [Q_A - Q_{Aref}^0]^T \gamma^2 [Q_A - Q_{Aref}^0]$$

where:

- $[V_p]$ ,  $[Q_A]$  are the vectors of the real-time measurements of pilot node voltages and the area reactive power levels.
- $[V_{Pref}^0]$ ,  $[Q_{Aref}^0]$  are the vectors of the optimal forecasted pilot node voltages and of the area reactive power levels.
- $\beta^2$ ,  $\gamma^2$  are weight diagonal matrices of the pilot voltages and area reactive power levels deviations with respect to the optimal-forecasted values.

With the adoption of this objective function an optimal compromise is reached between the need to have a desired voltage pattern and the need to maximize the area reactive power margins in respect to the control variable bounds.



### 3. The Italian electric power system model

The Italian electric power system has an installed capacity of about 73 GW, of which 20 GW come from hydro plants and 53 GW from thermal units. The overall generation on the 380 kV system corresponds to an installed capacity of about 35 GW.

#### 3.2 The original Italian transmission system model

The original model of the Italian network used in these studies is based on a representation of the 380 kV transmission grid only (namely 243 busses). All main generators (71 units) connected to the 380 kV network, as well as all the 380 kV interconnections with other countries, are explicitly represented in this system. It is important to mention that in this system the lower voltage levels (220-150-132 kV), including loads and generators, are simply represented through equivalent PQ injections at the corresponding 380 kV connecting busses.

The system model has been previously validated and used to perform recent system studies on the Italian grid.

In the 380 kV system model used here, the 220 kV and the sub transmission systems supply approximately 3.5 GW to the loads; this value was kept roughly fixed for the voltage stability studies reported here. In the base case adopted the import level on the 380 kV lines is approximately 3 GW. In the simulations performed for the calculations of the voltage collapse distance this level is allowed to increase following imposed load ramps and according to the maximum power transmission capacity.

The loading conditions of this network correspond to those on July 17, 1999, at 11:00 AM, with a total equivalent load at 380 kV level of about 22 GW, which is quite low in comparison to the typical peak loading conditions, which are in the order of 40 GW (just for reference the maximum loading levels registered on the Italian system have been in the order of 46 GW, with ENEL and IPPs supplying about 41.5 GW and imports of approximately 4.5 GW).

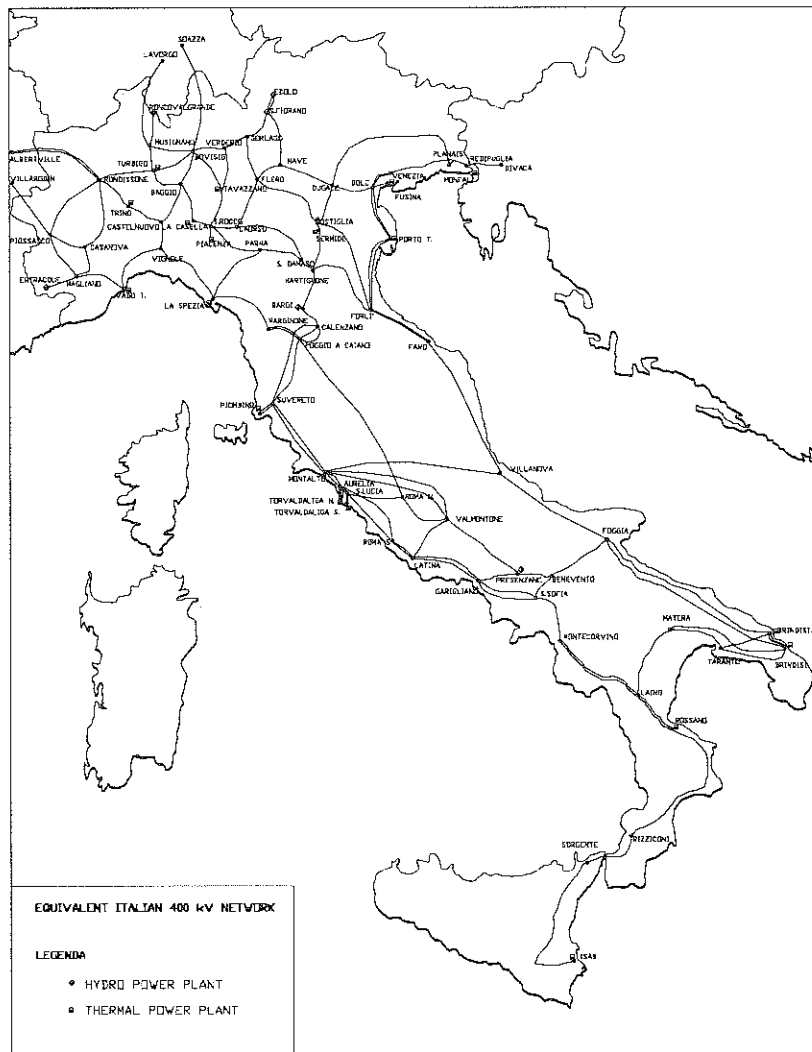


Fig.3 - Reduced model of the Italian transmission grid.

### 3.2 The reduced Italian transmission system model

The validation of the adopted hierarchical voltage control scheme was performed by the use of steady-state and dynamic simulation tools. In order to reduce the computational burden relevant to the dynamic simulations, two suitable equivalent of the original 243-busses 380 kV system were determined.

A 113-busses 380 kV system, with 29 generator busses was calculated and validated for the steady-state voltage collapse analysis (see the figure 3). For the dynamic analysis a further reduction was carried out which led at the end to a 65-busses 380 kV system model, with 25 generators.

The validation of the two models was preliminary performed by power flow calculations and then by a suitable sensitivity analysis, carried out to confirm the pilot node choice and the controlling power plants selection for each SVR area, as well as to compute the sensitivity matrices for tuning the controllers.

The voltage stability studies on the reduced Italian 380 kV system has assumed that only the largest loads in the different regions are modeled using a PQ representation and they are changed according to suitable predefined regional patterns.

For the other loads, including those representing power injections from the 220 kV or 150 kV networks and below, which add up to 9 GW of demand and 3.5 GW of injections, were described using impedance model, in such a way these loads are not dependent on the loading factor; thus, the powers on these loads do not increase as the system is loaded, rather, these powers tend to decrease due to system voltages degradation, mainly approaching the grid voltage instability or collapse operating conditions.

However, throughout all the studies on the reduced system, it could be observed that the powers on these loads tend to remain somewhat constant, as the voltages on the corresponding busses do not change significantly when the system is loaded. It is interesting to notice that, given the fact that some loads are modeled as impedance loads, the maximum loading or power transfer point of the reduced system does not necessarily coincide with the corresponding collapse or bifurcation point. In all cases, nevertheless, these two values were so close that for all practical purposes they can be considered to be the same, which somewhat validates the selection of the PQ representation of the loads.

### 4. The VOSTA static simulation model

The automatic procedure VOSTA (Voltage Stability), which is used here for the static simulation, provides an affordable estimation of the power system capability to be operated quite far from possible voltage instability limit conditions.

The actual security level is computed through an iterative procedure based on subsequent load variations, in such a way to stress the power system up to its voltage collapse limit. At each iteration, on the basis of the achieved load-flow solution and taking into account the system non linearity, suitable sensitivity indicators are computed considering the presence of primary, secondary and tertiary voltage regulations.

VOSTA is also capable to simulate corrective actions aimed to recover grid operating conditions acceptable from the point of view of voltage stability.

Such corrective actions regard the reactive compensation in the critical areas, as well as the active load tripping necessary for timely stopping the voltage instability phenomenon.

For both these purposes a suitable optimization algorithm, conceived for operational planning studies, is used and envisaged to be effective also for the tertiary regulation simulation. In the security assessment phase, VOSTA can take into account the possible operation of the system under contingency (like generator or line tripping) and perform suitable contingency screening and ranking.

The iterative procedure used by VOSTA is essentially based on the definition of the minimum active load increment  $\Delta C_{\min}^{(k)}$ , related to the corresponding reactive load increment, which at the k-iteration leads at least one controlling generator at its reactive power limitation (over or under excitation limit). The generators reaching their reactive power limits are switched from PV type nodes to PQ nodes.

The evaluation of  $\Delta C_{\min}^{(k)}$  is based on the sensitivity coefficients  $(\partial Q_{gi} / \partial C_{tot})^{(k)}$  related to the reactive power variation of the i-generator  $\Delta Q_{gi}^{(k)}$  with respect to the overall active load increment of the system  $\Delta C_{tot}^{(k)}$  according to the formula:

$$\Delta C_{\min}^{(k)} = \min_{i=1, N_{pv}^{(k)}} \left\{ \frac{(Q_{gi}^{(k)} - Q_{gi}^{(k)})}{(\partial Q_{gi} / \partial C_{tot})^{(k)}} \right\}$$

where:

- $N_{pv}^{(k)}$  is the number of generators which at the k-iteration may be represented as PV nodes because not arrived yet at their reactive power limits;
- $Q_{gi}^{(k)}$ ,  $Q_{gi}^{(k)}$  are the maximum and the current reactive power production levels respectively of the i-generator at the k-iteration.

The sensitivity coefficients  $(\partial Q_{gi} / \partial C_{tot})^{(k)}$  are computed by a linear combination of the reactive power generation derivatives with respect to the real and reactive power injections at the load nodes and to the real power variations at the generation nodes, taking into account the load characteristics. The computed total real load increment  $\Delta C_{\min}^{(k)}$  is then applied to each load bus according to the assumed evolution scenario and the initial load pattern.

#### 4.1 Static model of the primary voltage regulation

The static simulation of the primary voltage regulation loops (AVRs) is made assuming the control generators as PV type nodes until their capability limits are attained.

At the limits the type of such generator nodes is simply changed to PQ representation. They do not contribute any more to the grid voltage profile control.

Capability curves of the generators in the AVR can be exactly represented or, as a simplified alternative, only fixed rectangular stator and rotor limitations can be adopted.

#### 4.2 Static model of the secondary voltage regulation

The following algorithm performs the static simulation of the secondary voltage regulation (PQRs and RVRs).

- The pilot nodes are handled as PV type; as a consequence of the load increase fictitious reactive power injections  $\Delta Q_p$  appear to maintain the desired voltage levels. Resetting the SVR reactive levels  $\Delta Q_A$  eliminates the unbalances  $\Delta Q_p$ . The reactive power change of each area  $\Delta Q_A$  is obtained by the area matrix relations:

$$\Delta Q_A = \left( \frac{\partial Q_A}{\partial V_p} \right) \Delta V_p$$

$$\left( \frac{\partial Q_A}{\partial V_p} \right) = \left( \frac{\partial Q_p}{\partial Q_A} \right)^{-1} \left( \frac{\partial Q_p}{\partial V_p} \right)$$

where the matrix  $(\partial Q_p / \partial Q_A)$  is obtained by the weighted sum of the sensitivities of the reactive power injections in the pilot nodes with respect to the reactive power of the controlled generators (PQ type buses).

- The control generators are represented as PQ nodes, because they have to provide the required reactive power level for each area in order to keep the assigned pilot node voltage profile. Moreover all the plants within each area (under the RVR control), as well as all the units within each plant (under the PQR control), are managed to maintain a unique reactive power level, computed by each RVR and sent to all the PQRs operating under its control. This alignment assures a balanced exploitation of all the reactive resources in each area avoiding at the same time reactive loop flows among the units of the same plants, as well as among plants of the same area.

#### 4.3 Static model of the tertiary voltage regulation

At defined levels of the load increase in the ramp simulation the short-term reactive Optimal Power Flow (OPF) program NEWREA [25][26] determines the optimal values of the pilot node voltages and of the area reactive power levels following a minimum losses objective and taking care of the desired security constraints.

The static simulation of the tertiary voltage regulation in VOSTA requires the formulation and the solution of a suitable Optimization Problem (OP) with the OF already introduced in section 2.2. In the definition of the optimal set for the variables  $V_p$  and  $Q_A$  operational constraints must be satisfied on the generation terminal voltages. Besides in the model adopted for the SVR the variables  $Q_A$  are defined as function of the variable  $V_p$ . With this assumptions the OP constraints are the equality constraints that represent the relations between the area reactive levels and the pilot node voltages, the inequality constraints on the voltage at each generator bus and the lower and upper bounds on the control variables ( $V_p$  and  $Q_A$ ). Therefore the OP results as a standard quadratic programming problem, which can be generally expressed according to the following system:

$$\min_x \left( C^T x + \frac{1}{2} x^T H x \right)$$

$$Ax \leq b$$

$$\underline{x} \leq x \leq \bar{x}$$

For a system with  $N_{ASVR}$  secondary regulation areas in the problem OP the vector  $C$  of dimension  $(2N_{ASVR}, 1)$  is:

$$C^T = [-2V_{Pref1} \beta \dots -2V_{PrefN_{ASVR}} \beta \quad -2Q_{Aref1} \gamma \dots -2Q_{ArefN_{ASVR}} \gamma]$$

while  $H$  is a diagonal matrix of dimension  $(2N_{ASVR}, 2N_{ASVR})$  with the first  $N_{ASVR}$  entries the  $\beta$  coefficients, and the other entries the  $\gamma$  coefficients. Notice that vector  $C$  must be up-to-date only when short-term reactive OPF program NEWREA gives new optimal values of pilot nodes voltages and area reactive power levels, while the terms  $\beta$  and  $\gamma$  of diagonal matrix  $H$  is fixed initially by operator and then they are kept constant during all the simulations.

Matrix  $A$  and vector  $b$  contain the coefficients of the equality and inequality linearized constraints: a first group of  $N_{ASVR}$  rows of  $A$  contain the coefficients of equality constraints that link pilot nodes voltages with area reactive power levels according to the following relation:

$$Q_{Ai}^{(k)} = Q_{Ai}^{(k-1)} + \sum_{j=1}^{N_{ASVR}} \left( \frac{\partial Q_{Ai}}{\partial V_{pj}} \right)^{(k)} (V_{pj}^{(k)} - V_{pj}^{(k-1)}) \quad i=1, 2, \dots, N_{ASVR}$$

where  $V_{pj}^{(k)}$  and  $Q_{Ai}^{(k)}$  are respectively the  $j$ -pilot node voltage and the  $i$ -area reactive power at the current  $k$ -iteration, while  $V_{pj}^{(k-1)}$  e  $Q_{Ai}^{(k-1)}$  refer to the previous one. The calculation of  $(\partial Q_{Ai} / \partial V_{pj})^{(k)}$  is based on  $(\partial Q_A / \partial Q_p)^{(k)}$  and  $(\partial Q_p / \partial V_p)^{(k)}$  terms:

$$\left( \frac{\partial Q_{Ai}}{\partial V_{pj}} \right)^{(k)} = \sum_{l=1}^{N_{ASVR}} \left( \frac{\partial Q_{Ai}}{\partial Q_{pl}} \right)^{(k)} \left( \frac{\partial Q_{pl}}{\partial V_{pj}} \right)^{(k)} \quad i, j=1, 2, \dots, N_{ASVR}$$

The second and the third group of  $N_{GSR}$  rows ( $N_{GSR}$  is the number of control generators in SVR) contain the coefficients of inequality constraints on generator terminal voltages, given by the following formulas:

$$V_{Gimin} \leq V_{Gi}^{(k-1)} + \sum_{j=1}^{N_{ASVR}} \left( \frac{\partial V_{Gi}}{\partial V_{pj}} \right)^{(k)} (V_{pj}^{(k)} - V_{pj}^{(k-1)}) + \sum_{j=1}^{N_{ASVR}} \left( \frac{\partial V_{Gi}}{\partial Q_{Aj}} \right)^{(k)} (Q_{Aj}^{(k)} - Q_{Aj}^{(k-1)}) \leq V_{Gimax} \quad i=1, 2, \dots, N_{GSR}$$

At last the upper and lower bounds for control variables are built: they contain respectively the maximum and minimum values of pilot nodes voltages and area reactive power levels. The routines adopted for the OP solution, called SOLIS and QUADRI, are based respectively on the Rosen and Han-Powell algorithms. A new routine, called PREQUADRI, has been prepared in order to build the above matrix and vectors necessary for the optimization procedure.

### 5. The Easy5x dynamic simulation model

The tool Easy5x (Engineering Analysis System from Boeing Computer System), which is used here for the dynamic simulation of the reduced Italian power system model, is a software suited for system modeling, non linear simulation, design and validation of control systems. Easy5x is an integrated computation environment, with powerful computing capability and advanced graphical user interface, which allows:

- to build the system model by using standard blocks in predefined libraries, user blocks programmed in standard language or macro-components libraries: it is necessary to define the parameterization of the various blocks, the interconnection rules and, for the user blocks, the algebraic and differential equations of the mathematical model;
- to check the modeling coherency by verifying the correct definition and respect of the interconnection rules between the system variables, subdivided into input variables (or system parameter), state variables (characterized by ordinary differential or finite differences equations) and output variables (computed through algebraic equations);
- to achieve an ordered and explicit formulation of the equations describing the mathematical model, so creating the executable model which consists in a suitable sequence and syntax routine, with the overall system equations: such operation may put in evidence the presence of possible implicit or algebraic loops, which have to be removed;
- to produce the object code and to control the execution flow, by using of the native resources of the workstation as concerns both the compilation and the source level debugging features, executable directly within the session;
- to allow the execution of the following analysis:
  - steady-state: search of an equilibrium operating condition of the system, characterized by a state derivative vector with predefined minimum norm;
  - simulation: computation of the transient responses of the system, following perturbations injected on some input variables: different type and order numerical integration methods are used, explicit or implicit ones, whose evolution is controlled through interactive graphical primitives (slider, button, strip-chart);
  - linear model generation: determination of the system model linearization around a steady-state condition, evaluation of the transition, input and output matrices, as well as the eigenvalues and eigenvectors;
  - transfer function and frequency response: computation of the linearized system matrices of an input-output transfer function and plot of the frequency responses;
  - root locus and eigenvalues sensitivity: evaluation of the sensitivity and plotting of the geometrical locus of the positions reached in the complex plane by the linearized system eigenvalues, changing a particular system input variable (or parameter);
  - stability margins: determination of the maximum variations allowed to a particular input variable without destabilizing the linearized system, that is the positioning of at least one eigenvalue in the half left complex plane with positive real part.

Easy5x is used here with a macro-components library, mainly oriented to the simulation of electric power systems (Power System Library), containing the dynamic models commonly proposed in literature or subjected to international standard. These models may be used for the dynamic analysis of generation and transmission systems (load-flow computations, synchronous/asynchronous generators and motors, excitation systems of static or rotating type, turbines of conventional or innovative type, unit/plant/grid control systems, HVDC systems and FACTS controllers, etc.), with particular regard to the design review and dynamic performance validation of control and regulation (AVR, PQR, RVR, NVR, EHC, PLU, etc).

Such models have been effectively used for short-term dynamics analysis, concerning electromechanical and torsion stability problems, as well as synchronous generators operating point limitation, design review and performance validation of excitation control systems and conventional and combined cycle turbines governors. Long-term dynamics network studies, devoted to voltage instability and collapse phenomena or secondary and tertiary grid voltage regulation problems, have been also carried out by using of these dynamic models.

#### 5.1 Dynamic model of the primary voltage regulation

The dynamic simulation of the primary voltage regulation loops (AVRs), which represents the lowest and perhaps the most critical level of the hierarchical control structure, is made assuming the presence of terminal voltage control, active and reactive feedback compound, over-excitation field current limit, under-excitation reactive current limit, stator over-flux and current limit, power system stabilization.

Such a level allows, through the field current control of static or rotating excitation systems, the primary terminal voltage control of the synchronous generators, in order to hold the unit machine voltages at the references, either fixed by a constant or forecasted profile or by the set-point overlapping of PQR operating at higher hierarchical level.

#### 5.2 Dynamic model of the secondary voltage regulation

The dynamic simulation of the secondary voltage regulation (PQRs and RVRs) is based on a quite sophisticated modeling of both the control of the power plant reactive levels and the pilot node voltage regulation.

In particular the PI control law of the PQR is modeled with a SISO transfer function, between each reactive power error and each overlapped deviation of the primary voltage set-point. By this way each power plant is represented as an equivalent single machine, that is all the power plant units are assumed balanced in their set-point following and no reactive power flow or dynamic interaction between the units is here considered. These effects may be really neglected due to the complete dynamic de-coupling implemented in the actual PQR control apparatus. The PI control law of the RVR is modeled instead with a MIMO transfer function, between the pilot node voltage errors and the overlapped deviations of the reactive power set-points. By this way each pilot node regulation is properly coordinated and de-coupled from the other pilot nodes controls, so reducing the reciprocal dynamic interactions between electrical areas.

### 5.3 Dynamic model of the tertiary voltage regulation

The dynamic simulation of the tertiary voltage regulation (NVR) is based on a quite simple modeling of the objective function minimization, compromising the expected pilot node voltages with the area reactive power levels. The reactive power dispatching is simulated only at the beginning of the considered transients, that is no very short-term rescheduling is here taken into account during the dynamic investigation.

The quadratic optimization problem is solved by a suitable transformation into an equivalent linear regulation problem, where the non linear system equations constraints are linearized around a quasi steady-state condition and the objective function derivatives are kept to zero through an integral control law, with quite slow dynamics and high time constant, acting on the basis of their instantaneous values according to the formula:

$$\begin{cases} \beta^2 [\Delta V_p - \Delta V_{p_{ref}}] + \gamma^2 S^{-1} [\Delta Q_A - \Delta Q_{A_{ref}}] = 0 \\ \Delta V_p = S \Delta Q_A \\ \Delta V_{p_{ref}} = \Delta V_p \end{cases}$$

The I control law of the NVR is modeled with a MIMO transfer function, between the pilot node voltage errors  $[\Delta V_p]$ , the area reactive levels deviations  $[\Delta Q_A]$  and the corrections  $[\Delta V_{p_{ref}}]$  on the pilot node voltage set-points sent to the RVRs, with the assumption that the SVR control loops are in steady-state operation as far concerns the TVR optimization problem. Each pilot node regulation is properly coordinated and coupled with the other pilot node controls, so controlling the reciprocal dynamic interactions between electrically near areas and establishing the mutual reactive support levels.

## 6. The voltage stability indicators

Both the static and the dynamic simulation tools and models provide suitable voltage stability indicators capable to give indications about the proximity of the current grid operating point to the voltage instability and collapse limit.

VOSTA computes, at each iteration, the following stability indices, which are also used to manage the scenario evolution:

- $\partial Q_{\text{tot}} / \partial Q_{\text{ctot}}$ : the sensitivity of the total reactive power production level with respect to the total reactive power consumption level;
- $\partial V_{hj} / \partial P_{chj}, \partial V_{hj} / \partial Q_{chj}$ : the sensitivity of the j-area h-node of PQ type voltage with respect to its corresponding active and reactive power load levels;
- $\partial V_{pj} / \partial Q_{cj}$ : the sensitivity of the j-area pilot node voltage with respect to the area reactive power consumption;
- $\partial Q_{g,areaj} / \partial Q_{c,areaj}$ : the sensitivity of the j-area reactive power production with respect to the area reactive power consumption.

The sensitivity coefficient  $\partial V_{hj} / \partial Q_{chj}$  is mainly assumed as a local indicator which, in secure conditions, takes small negative values while, approaching the voltage instability or collapse, grows in absolute value up to suddenly change its sign.

The index  $\partial Q_{\text{tot}} / \partial Q_{\text{ctot}}$  is instead assumed as a global indicator. In secure states, it is positive and assumes values near the unit while, approaching the voltage instability or collapse, it grows rapidly up to suddenly become negative. Both of these indicators are strongly non-linear, mainly near the critical grid stability conditions. It becomes therefore important to search for a more linear indicator, which may be based on eigenvalues or singular values computation of the inverse Jacobian matrix of the load-flow equations:

- $\sigma_{\text{max}}$ : maximum singular value of the Jacobian matrix (first order index), assuming a very high positive value near the voltage instability or collapse point;
- $\sigma_{\text{max}} / \partial \sigma_{\text{max}} / \partial C_{\text{tot}}$ : ratio between the first order index and its sensitivity with respect to the real load demand (second order index), remaining quite linear also in proximity of critical grid stability conditions.

In combination with the above defined static voltage stability indices computed by VOSTA, a real-time dynamic indicator of the proximity to voltage instability of a current network operating point is computed by the Easy5x dynamic simulation model here used through a simple deterministic algorithm and in a short time of few seconds, on the basis of control measurements and signals.

For using such a real-time index it is necessary the availability on the field of an automatic control system of the transmission network voltages (i.e. SVR and TVR). With reference to the instantaneous value  $Q_{Ai}(t)$  of the i-area reactive power level, the real-time proximity indicator  $VSI_i(t)$  to the i-area voltage stability limit, is given by the following formula:

$$VSI_i(t) = Q_{Ai}(t) + \rho \dot{Q}_{Ai}(t)$$

where  $\rho$  is a weight coefficient, which allows an effective setting of the derivative term for taking into account the reactive power level dynamics and therefore of its expected short-term trend, while  $-1 \leq Q_{Ai}(t) \leq 1 + \varepsilon(\tilde{Q}_{Ai}(t) - 1)$ . The term  $\varepsilon(\tilde{Q}_{Ai}(t) - 1)$  represents a contribution, usually kept at 0 value, which can take positive growing values according to the pilot node voltage regulation effort, in case some of the units of i-area can be transiently overloaded with respect of their over-excitation limits: only in this situation the regulator state  $\tilde{Q}_{Ai}(t)$  and the actual reactive power level  $Q_{Ai}(t)$  may differ.

The  $VSI_i(t)$  index represents useful real-time information for the operators, which can be drawn by it, when given thresholds are exceeded, to look over the critical state of the i-area voltages. According with this area alarm, RVR operates to avoid the units operation at the over-excitation limits, because this condition is normally related to the tap-changer reverse action which can anticipate the voltage collapse triggering: this is achieved controlling in advance all the possible reactive power resources (capacitors banks, reactors, synchronous or static compensators) installed in the i-area to reduce the  $Q_{Ai}(t)$  operating value and therefore the control effort of the units.

## 7. Examples of simulation results

In this paragraph the results of some simulations are shown, based on the static and dynamic model assumptions described above and achieved with reference to the overall simplified Italian transmission network, as well as to some partial areas of particular interest in such a network. For each simulation case the same load pattern is taken into account and corresponds to a distributed load ramp increase, according to suitable area participation coefficients. In the presented examples the following issues have been observed:

- evaluation of the load margins modifications due to the different voltage control coordination (primary, secondary or tertiary voltage regulation in service);
- comparison between the simulation results achieved by the different simulation models and tools (static simulation by VOSTA or dynamic simulation by Easy5x);
- analysis of the stability indices performances based on the different computation approaches (static sensitivity indices or dynamic real-time reactive margin index).

The initial grid conditions have been established according to an optimal reactive power dispatching, which has considered the coordinated voltage control configuration of table 1. Such a configuration has been achieved, for the simplified Italian transmission model, through a preliminary sensitivity analysis which has selected the pilot nodes, computing and reordering the short circuit power matrix on the base of the short circuit power. For the pilot nodes it results sufficiently high for representing all the other area buses voltages. The same procedure has allowed also the control areas determination, in order to have a low electrical coupling between them. For the control generators choice, the sensitivity matrix containing information about the reciprocal coupling between the generators and the grid nodes (in particular the pilot nodes) has been instead used. This procedure allows the selection of the units capable to produce the strongest voltage variation at the pilot nodes for a given modification of the reactive production.

| Pilot Nodes | Control Areas  | Controlling Power Plants                                 |
|-------------|----------------|----------------------------------------------------------|
| MAGLIANO    | Piemonte       | Entracque, Vado Ligure                                   |
| BOVISIO     | Lombardia 1    | La Casella, Piacenza, Tavazzano, Turbigo, Roncovalgrande |
| S.FIORANO   | Lombardia 2    | Edolo, S.Fiorano                                         |
| DOLO        | Friuli         | Monfalcone, Fusina, Porto Tolle                          |
| MARTIGNONE  | Toscana/Emilia | Sermide, Ostiglia, Bargi                                 |
| AURELIA     | Lazio          | Montalto di Castro, Torvaldaliga Nord, Torvaldaliga Sud  |
| BRINDISI    | Puglia         | Brindisi Sud                                             |
| ROSSANO     | Calabria       | Rossano Calabro                                          |
| ISAB ERG    | Sicilia        | Isab Erg                                                 |

Tab.1 – Secondary voltage regulation configuration.

The load ramp increments have been applied at each VOSTA iteration at constant power factor and at a constant power rate of 250 MW, in order to approach the unit reactive power limitations or voltage instability conditions in the same manner for all the considered voltage control configurations. This choice allows a more precise comparison between the voltage control configurations themselves, despite of a less precise evaluation of the actual load margins of the simplified grid model. In the dynamic simulation by Easy5x the adopted load ramp gradients are largely below the maximum values allowed by the primary units regulations.

The participation coefficients to the load ramps increase are summarized in the following table 2, with reference to the present Italian grid subdivision in electrical regions.

| Electrical region | Load ramp participation coefficients |
|-------------------|--------------------------------------|
| Torino            | 15%                                  |
| Milano            | 30%                                  |
| Venezia           | 20%                                  |
| Firenze           | 10%                                  |
| Roma              | 10%                                  |
| Napoli            | 10%                                  |
| Palermo           | 5%                                   |

Tab.2 – Load ramp participation coefficients.

### 7.1 Milano-Torino case: static vs. dynamic results comparison

The first study case presented here concerns the Milano and Torino electrical regions and involves a load ramps increase at the nodes of Magliano, Castelnuovo, Casanova (Torino area), Baggio, Bovisio and Nave (Milano area). From this study case it is possible to compare the static and dynamic simulation results, achieved by the use of VOSTA and Easy5x:

- Figure 4a: the quasi-static behavior of the P-V curve at the Magliano pilot node exhibits an amount of load margin increase, due to the presence of SVR and TVR, of about 1000 MW for the overall Italian grid. The load margins increases with TVR and SVR operation are basically coincident. The figure puts shows the point where the Piemonte area reaches its capability limits: it can be seen that the attainment of the saturation limits is strongly delayed if also the TVR is in operation.
- Figure 4b: the above considerations are still valid as concerns also the quasi-static behavior of the P-V curve achieved through VOSTA at the Bovisio pilot node.
- Figure 4c: the quasi-static behavior of the  $\sigma_{\max}$  voltage stability indicator is rather flat during the load ramps evolution and assumes a very high positive value near the voltage instability or collapse point. The typical amount of load margins increase due to the presence of SVR and TVR is confirmed at 1000 MW for the overall Italian grid.
- Figure 4d: the same considerations are valid as concerns the behavior of the voltage stability indicator  $\partial Q_{\text{grid}} / \partial Q_{\text{tot}}$ . These strong non-linear behaviors make impossible to use in a real-time monitoring and control framework such a kind of indicators, which are instead very effective for off-line and short-term planning.

Fig. 4a – Magliano pilot node P-V curve.

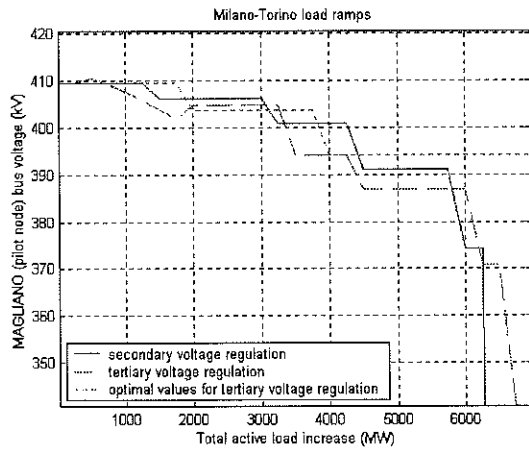


Fig. 4b – Bovisio pilot node P-V curve.

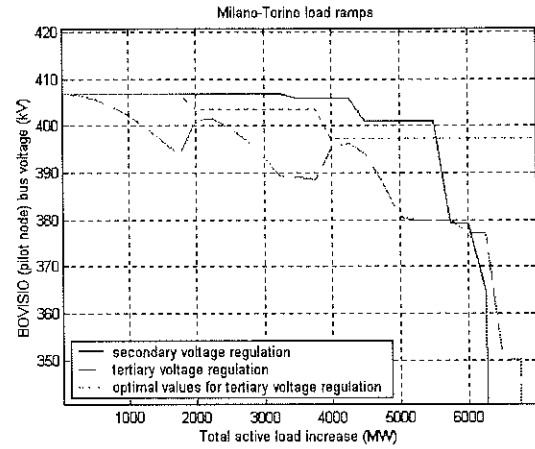


Fig. 4c – Sigma max voltage stability indicator.

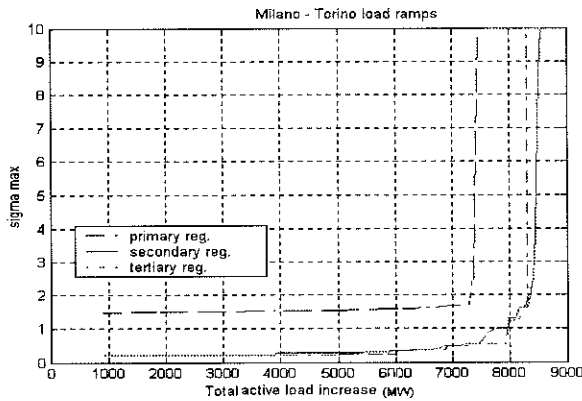
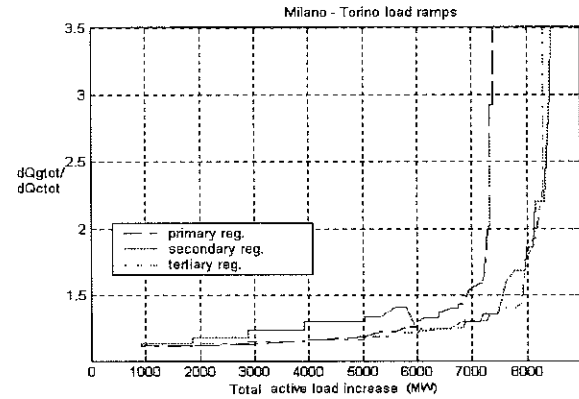
Fig. 4d –  $dQ_{gtot}/dQ_{ctot}$  voltage stability indicator.

Fig. 4 – Milano-Torino load ramps stability margins static evaluation.

- Figure 5a: the dynamic behavior of the voltage profiles at the Magliano and Bovisio pilot nodes exhibit an evident improvement in case of SVR and TVR operation. A time margin of about 100s is gained by the voltage regulation coordination with respect to the primary voltage control.
- Figure 5b: the P-V trajectories put in evidence the same stability improving effect in terms of both voltage profile (very flat within the coordinated control capabilities) and load margins (150 MW and 500 MW margin increases are achieved at Magliano and Bovisio respectively).
- Figure 5c: the reactive powers delivered by the plants of Entracque and Vado Ligure in the Magliano area exhibit a uniform behavior up to their reactive limitation, which is quite near the voltage instability and collapse conditions.
- Figure 5d: the above considerations are still valid as concerns also the reactive powers delivered by the plants of Tavazzano and Turbigo in the Bovisio area.

From this study case it is not possible to appreciate the real load margins improvements due to the SVR coordination by the TVR, because this has been only preliminary tuned: therefore better TVR performance can be expected in the actual scenario, as shown in the following study cases.

## 7.2 Roma-Firenze case: SVR vs. TVR dynamic comparison

The second study case, presented here, concerns the Roma and Firenze electrical regions and involves a load ramps increase at the nodes of Fano, Roma Nord, Roma Sud, S.Lucia and Villanova (Roma area), Forli, Martignone, Parma, Poggio a Caiano and S.Damaso (Firenze area). From this study case it is possible to compare the dynamic simulation results achieved with only the SVR and also the TVR respectively in service:

- Figure 6a: the P-V trajectory puts in evidence the stability improving effect in terms of both voltage profile (very flat within the coordinated control capabilities) and load margins (the same margin increases of 200 MW are achieved at Parma Vigheffio and Poggio Caiano).
- Figure 6b: the P-V trajectory puts in evidence the same stability improving effect, in terms of both voltage profile and load margins (200 MW and 300 MW margin increases are achieved at Roma Nord and Sud respectively).
- Figure 6c: the reactive powers delivered in the Martignone area by the plants of Bargi (in primary control) and Piombino (in secondary control) exhibit a uniform behavior up to the reactive limitation and voltage collapse.

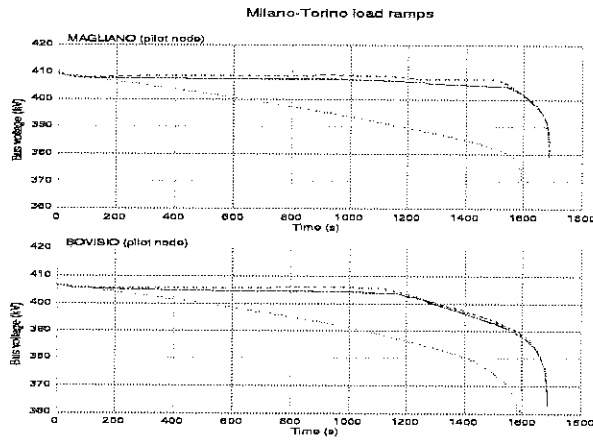
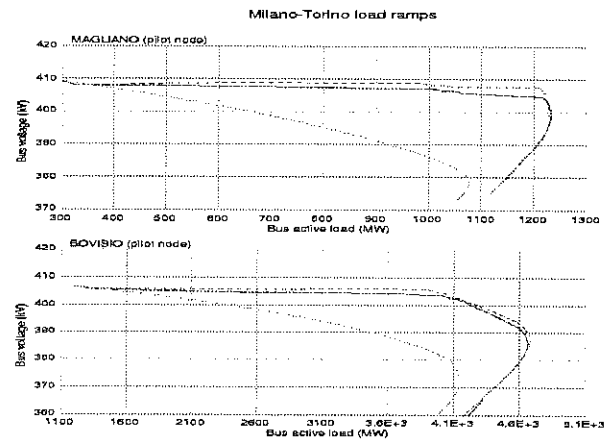
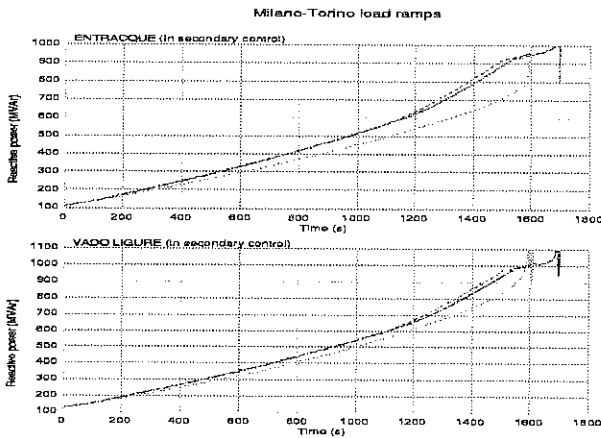
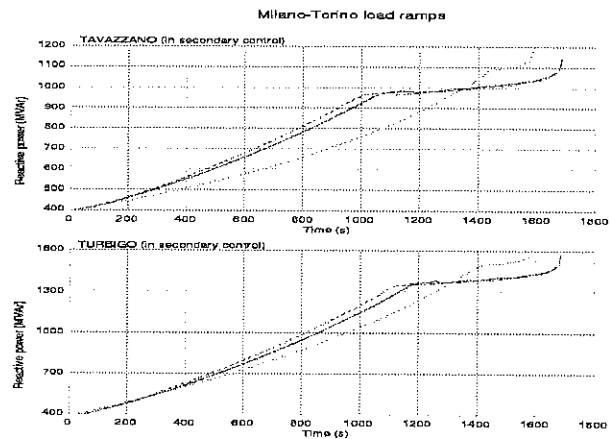
Fig. 5a – Magliano and Bovisio pilot nodes  $V(t)$  curves.Fig. 5b – Magliano and Bovisio pilot nodes  $P-V$  curves.Fig. 5c – Entracque and Vado Ligure  $Q(t)$  curves.Fig. 5d – Tavazzano and Turbigo  $Q(t)$  curves.

Fig. 5 – Milano-Torino load ramps stability margins dynamic evaluation:

- continuous line: primary voltage regulation,
- dotted line: secondary voltage regulation,
- dashed line: tertiary voltage regulation.

- Figure 6d: the reactive powers delivered by the power plants of Torvaldaliga and Montalto in the Aurelia area exhibit the same behavior up to the reactive limitation, more retarded by the SVR and TVR coordination.

Further TVR performance improvement can be expected again by means of the very short-term reactive power re-dispatching, as shown in the following study case.

### 7.2 Italian grid case: SVR vs. TVR static comparison

The third study case presented here concerns the overall Italian electrical regions and involves a load ramps increase at all the nodes according to the participation factors of table 2.

It has to be noted that in this particular simulation the very short-term reactive power re-dispatching has been simulated also: more precisely the TVR uses four different optimal pilot nodes voltages and area reactive levels profiles, recomputed at every 2000 MW of total load increase.

From this study case it is possible to appreciate also in the results obtained from a steady state simulation the maximum load margins increase achieved by the presence of TVR in service with respect to the scenario where the transmission network is operated only under the SVR control:

- Figure 7a: the behavior of the steady state voltage stability indicator  $\sigma_{\max}$  is rather flat during the load ramps evolution and assumes a very high positive value near the voltage instability or collapse point. The largest amount of load margins increase due to the presence of SVR and TVR is achieved at 1500 MW for the overall Italian grid.
- Figure 7b: the same considerations are valid as concerns the quasi-static behavior of the voltage stability indicator  $\partial Q_{\text{tot}} / \partial Q_{\text{ctot}}$ . Also in this case strong non-linear behavior are in evidence for this kind of indicators, on the basis of which more a qualitative than a quantitative load margins evaluation is typically provided.



Fig. 6a – Parma Vigheffio and Poggio a Caiano P-V curves.

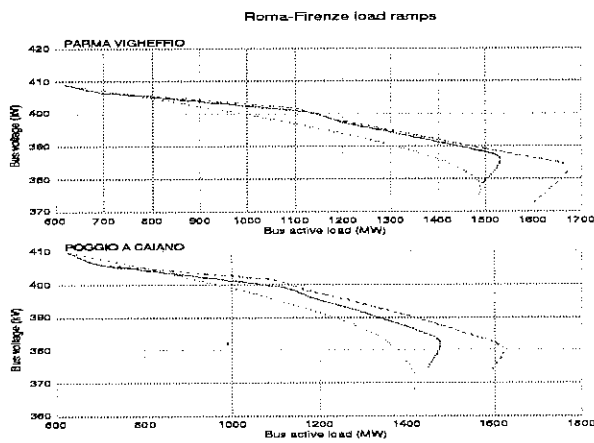


Fig. 6b – Roma Nord and Roma Sud P-V curves.

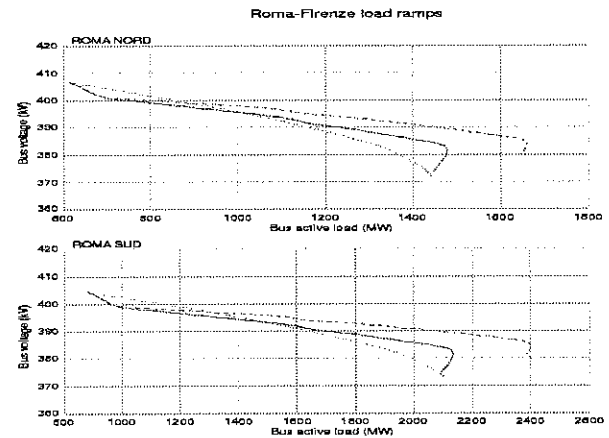


Fig. 6c – Bargi and Piombino Q(t) curves.

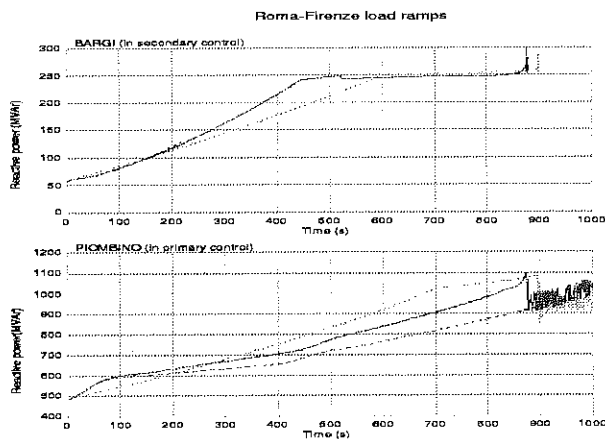


Fig. 6d – Torvaldaliga and Montalto Q(t) curves.

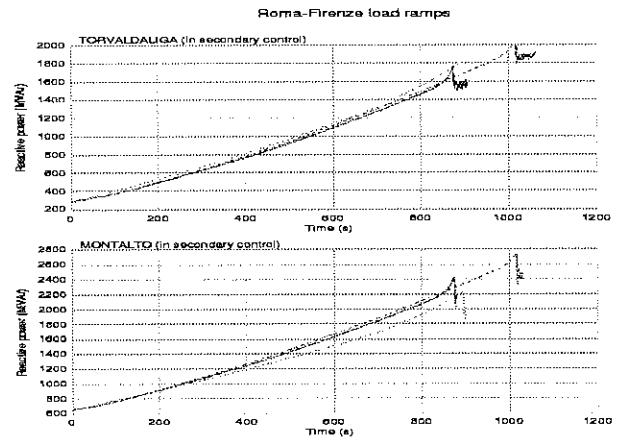


Fig. 6 – Roma-Firenze load ramps stability margins dynamic evaluation:

- continuous line: primary voltage regulation,
- dotted line: secondary voltage regulation,
- dashed line: tertiary voltage regulation.

## 8. Conclusions

The paper has presented a collection of static and dynamic modeling tools and simulation results aim to evaluate the load margins of a transmission system, with respect to the voltage instability and collapse phenomena. In the considered Italian grid the automatic control system of the transmission network voltages (SVR and TVR) has been recognized as an effective coordinator of the reactive power resources. Suitable static and dynamic analyses have shown in fact that the SVR and TVR increase the load-ability of the transmission system, result demonstrated also by computing suitable off-line and on-line voltage stability indicators. The SVR and TVR have proven themselves to operate together for avoiding the units operation at the over-excitation limits, so allowing the grid operators to achieve a more full exploitation of the power transfer capabilities of the transmission networks, as required by the restructured and liberalized electric energy markets.

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Fig.7a – Sigma max voltage stability indicator.

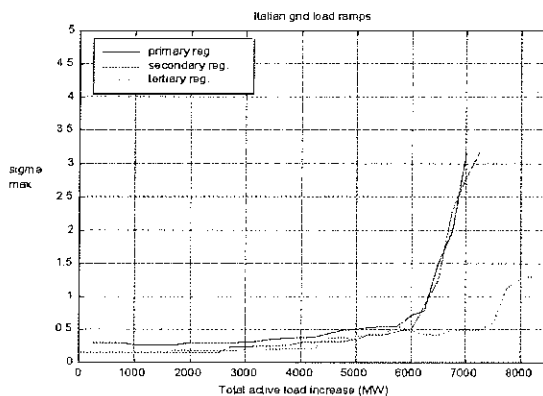
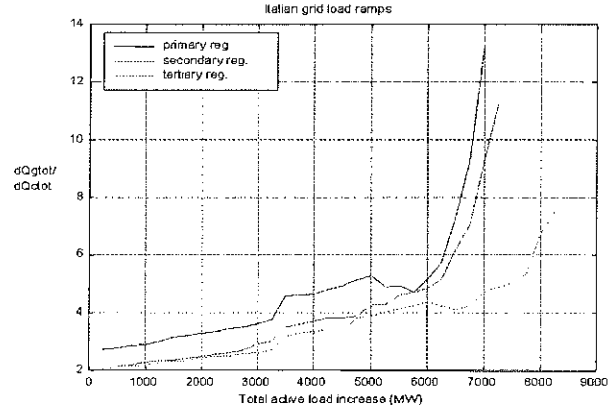
Fig.7b –  $dQ_{gtot}/dQ_{ctot}$  voltage stability indicator.

Fig.7 – Italian grid load ramps stability margins static evaluation.

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## Discussions on Session VII: CONTROL Part 1

**Chairman (C.-C. Liu):** This session is about the control issues. The first speaker, David, talked about complexity and complex system, hybrid system, and global system. The next paper is about state space linearization. The third and fourth papers were about secondary and tertiary control techniques. I also like to invite the speakers to raise any issue they like to discuss here.

**L. Fink:** This is for David Hill. It's more of a comment, which he may or may not wish to respond. What I found very refreshing about his paper, very impressive also, was the way he backed off and took a fresh look at the power system control problem from the standpoint of control engineering or even control theory. I found it excellent and stimulating. But I would like to invite further drawing back from the problem from the point of the ongoing process of restructuring the system, which has been going on now for more than a decade. What happened is, over the past century, the evolution of power systems reflected the symbiotic evolution of system, corporate and economic structure along with power system structures. So by the end of system, they were effective, roughly optimal and congruent with each other. Now all of these corporate and economic structures have been torn into pieces and thrown in the air, and we're waiting to see where they settle out. Obviously it's not going to be the central hierarchy system we had before. I see this as a tremendous challenge to control thinking. Because it gives you a chance to step back and say you got a completely new structure. How can we design a control structure that is congruent to the new corporate economic structure? Not much of anything going on like this. The usual approach is to say, well, that's an engineering problem, we'll set up an independent system operator, and help it in controlling system just like we always did, meanwhile the economist also will figure out who pays who how much. I think we're seeing it not an effective approach to the problem. So the challenge, given the new corporate structures, how can we effectively design de-centralized control structures that are congruent as the old control structure were for their situation?

**D. Hill:** There is no doubt that there is a tension between the engineering and the economic sides right now. In Australia, for example, I encounter this recently doing some consulting on what's called generic limit in the market mechanism. It's clearly a conflict going on. The market structure put you in a situation where you can't include enough information about security get a good answer about security just at the time when they're worried about being accountable for those security limits. We're quite happy to have an estimate in the way

the edges, and just leave some distance away. Now we're going to be accountable for these distances we have from those edges, we need to find precisely and so and so. Definite tension. I really don't know how that is going to be resolved. I'd like to think the engineers would have a say, maybe the economists have to back off, and so we can do what is needed to keep the system up. So I can only say I agree that there is a tension there, and it remains to be seen how that pans out. It's not really clear in the Australia context, when the things got really tough, that they can keep the market with the current structure and do a decent job with the security. Maybe they need to let go off the market structure and lay out a different structure, which would give more a greater ability to carry out the security control. So that is just a general comment on that.

**S. Corsi:** Generally speaking it is true that the centralized control system in comparison with the hierarchical system, in a way, having a coordination between the centralized application through this decision, generally speaking, you achieve a more suitable effective control solution. Usually it points to which kind of functionality and which kind of links inside. But generally speaking, it coordinates and gives some problems. I also want to add an issue related to the situation of possible congestion considering the loading of some lines. Also in this case, we notice that the concept of the control system previously shown strongly support the improved situation. I see really something against the centralized coordination against the fact of liberation. Probably we have to check better the new situation and try to find the possible additional improvement of some model, robust adaptive functionalities in the way to increase the robustness of the control system.

**M. Sekoguchi:** In Japan, for the economical and environmental reasons, it's difficult to build new transmission lines. So for many programs in power system, for example, global model. So it's important to develop an economical countermeasure, for example, control or as an economical measure.

**Chairman:** I can add comments on L. Fink's questions. This is an interesting application of multi-agents system. That framework that says: Power system is not just the equations, it's the system model, it's the market model, it's the protection system model, it's operator model, and there are other things involved in there. If you organize the whole structure into a multi-agent system, each agent is supposed to perform certain tasks with whatever algorithms, or search, or equations, or theorems, and

then you provide the coordination framework for it. Then I think you have a good analytical framework to analyze different kinds of problems there.

**D. Hill:** Could I just add a little bit to that quote. Les' s question about congruence between the economic and the technical. I heard a very interesting talk by Felix Wu not long ago in Hong Kong. He introduced the new concept to me - coopetition, I think it's some mixture join cooperation and competition going back to history. I think some new ideas in economics might help get this congruence. We can work on the control side, there maybe some refinements of revolution that can come along the economic side.

**Ian Dobson** (University of Wisconsin): I have a question for David. One theme in power system control is that of de-coupling the controllers from each other, or from one another. There is a number of ways, for example, time scale separation, filtering inputs you don't see certain things, or even in extreme just turning the controller. Now for global controls, one is fully integrated all the controllers for all different purposes in a power system, and another extreme is to explicitly design in or enforce this kind of de-coupling, so you can look at the sub-systems. I wonder what your comment was about how you think global control should go with respect to this issue?

**D. Hill:** That's a really good question. A lot of the de-coupling that uses some of the time scale separation is perhaps still there, but the sort of de-coupling we use in load flow, and using DC load model, and for instance in PSS design went back a long time. I think by my observation the loading level is naturally de-coupling. A lot of those de-couplings do not work in stressed systems, and that's where we are. That's the discussion by the ABB folks the other day, they set up a system to operate out there in the edge, and a lot of those can vanish, so they are not the issue anymore. But I think there are some still there. Of course they can be built in the time separation if that is naturally there, then that can be in the global control. That's no problem. So it's not a complete jump to just mix up and create all that unnecessary complexity. I think there is still the idea to minimize the complexity, but a lot of the complexity is just going to happen naturally, particularly the breakdown of this assumptions the way it used to the loading levels.

**S. Corsi:** About today the dynamic de-coupling I show before the control system, I want to say that this kind of choice, the area division and the organization is strongly related to the problem of voltage control which is a local problem. You have to use the local resources. Usually for example, the frequency control is a fully different solution.

**D. Hill:** I just want to say that my main idea is relevant

the way you have one device, which can contribute in a couple problems. When you got a device addressing a particular issue, and you're happy, just stay as before. But like with excitation or load control, you contribute to all sorts of things, and that's mainly what I'm referring to here, to get the most out of that.

**C. Vournas** (NTUA): I would like to get back to the question by Les Fink in the context of two of the paper e presented here. The real challenge for control is to have a controller that would be able to adjust to changing conditions. With the centralized structure you pretty much know how the generation pattern would go. But in the Market? You don't know what the generation pattern will be. So the paper by Professor Sekoguchi, somehow address this problem by identifying the system to which the generator is connected. So I would stress this part of your presentation and ask you Dr. Sekoguchi if perhaps you can elaborate a little bit more on how you estimate the parameters of the infinite bus system. If you're able to do this, and then in a changing operating condition, adjust your control to what is going on, then this is one way out. On the other hand, you have the Italian coordinated control, and this is also a problem in the new environment. You have a good solution, but in order to apply it, then you have to convince generators that they somehow benefit from it. That is, secondary voltage control should be somehow paid back as an ancillary service to those generators that are willing to adjust and participate in a coordinated control.

**Chairman:** We'll have Dr. Sekoguchi to respond to the question. The question is how you estimate the parameters of the infinite bus. Your controller is tied to a machine and infinite bus. How do you estimate the parameter of that infinite bus for your controller design?

**M. Sekoguchi:** We assume the capacity is infinite. We calculate the infinite bus voltage, system resistance and reactance by calculating the generator local active power, reactive power and terminal voltage and current. Detailed equations are shown in the paper.

**M. Delfanti:** Again for the Italian, the situation is quite particular. So the problem of non-linear service is for voltage control, it's not seen as much as market, but it is seen as something of maybe mandatory for all generators connected to the grid. So they didn't decide, maybe that some money would be paid those people who participate in the voltage regulation. Mainly what we have seen in the test and the results is that it's really not common to find a test, in which some of the generators are added to move along the capability chart in order to reduce the active generation to contribute to voltage regulation. So as long as you don't move the active generation in any unit, you don't put that much money again because the difference in the performance efficiency of the generator between the just active power and generation reactive power is just some few

percent, let's say 0.1% of your load. So you don't put that much money again. It seems that those units will take part in the secondary voltage regulation will get some money just for the maintenance of the control part of the system, and for the availability to move the operating point of the group. But it does not seem very critical from the economical point of view, so we're really de-coupling the issue between the technical and the economical.

**C. Canizares:** I'm taking up what Les was saying here. I think all of you prove through the introduction of these controllers, and the way to sell them is that you increase the transfer capability to where you decrease congestion like David showed us that you basically have a stable system. I guess all of you basically look at it from that point of view. That will mean that you will reduce your marginal prices on the loads and the needs that you're using, or you reduce the congestion and then you will be able to sell that way, I presume. My problem is that you don't have a congestion problem like in the Italian system, then how are you going to sell this to the generators? How are you going to convince them to participate on this? I know Sandro has been quite involved on this because you do have the real problem that you really have generators participating in this coordinated control. Now the market is coming. So what is your view of how you're going to convince besides the fact that there is a load, I guess? How do you convince them that they have to be part of that you can continue with this implementation of secondary voltage regulation?

**S. Corsi:** Yes. The examples we showed in the papers and the analysis we performed confirmed that, among the situations with the open market, it appears the control system application is in support and to facilitate in a certain case. I want to say the way in which the control system allows the security, the quality and economy also of operation. Another aspect of the economical recognition and the definition of this support is by act of the market. The problem is considered also in the paper I presented. It is about the individual power plant participation index to voltage ancillary service and voltage support. It is mainly linked to this area to find a simple and practical way to have a correct recognition over the contribution of the power plant of the generation to this kind of ancillary service. I want to say when the generator of the secondary voltage control is fully available up to the limits automatically controlled by a system with the overall network. Usually this kind of support must be correctly recognized economically. Also in this case, you have no doubt about the contribution was performed by one generator with a competitor or without, because according to this kind of participation, you can correctly see and recognize the contribution.

**M. Begovic:** I have a question for all of the authors.

You provide proposals for very complicated answers to even more complicated questions, and that is the reality we would be facing. At the time when we speak about this solution, it becomes increasingly certain that within the time frame of years at most, we shall also need to incorporate into those solutions, the distributed generation. Thinking of the distributed generation as anything any generation resources connected on the feeder side are the traditional approach to solving the problem and modeling sub-stations as loads of either static or dynamic kind will have to be adjusted. So my quick question for all of you is whether you see the distributed generation as a blessing or impediment to the proposed solution you're talking about in your paper.

**S. Corsi:** As far as voltage control is concerned, you have to regulate the transmission network. Having robust control of the transmission network, you're able to fix the voltage of the transmission. This is a useful support to the distribution, because the load changes the taps and so on. After that you can manage locally for each area of distribution. The solution according to the distribution generator and generation is open. You start from an important point. You have a transmission network with very strong voltage, like a fixed point voltage.

**M. Delfanti:** Just for the Italian case, I don't think the distributed generation will have a great impact on voltage regulation. You have to consider that our peak load is 50 GW. The overall installed capacity is 70 GW, just on major voltage levels. Some of these plants are now been re-powered. I don't think that will have more than 10,000 MW undistributed, so it's just a minor part. Most of these will be devoted to corporate peak load hours, so we can not rely on these generations for a complete support of voltage. It seems that, at least for our system, it will not be so critical in this aspect. About the question before Claudio, of course we are in Italy. Two years ago, the first thing they stated is how much you have pay for voltage regulation service? They do already collect all the loads in the system in the last two years. They collected 0.5 lira per kilowatt, even if they don't actually know who will get this money.

**M. Sekoguchi:** I think non-linear control has robustness and it is to design the controller parameter, so we'll try to apply to distributed generation area.

**D. Hill:** I just have a brief comment following Claudio's question. If I understood it, he hinted at an important research question, which is to value the benefit of control. We had in reliability study in the past, you know you quantify the value of loads, and so we need really good valuation of the benefit of control, otherwise all of this wonderful technology goes nowhere. I think that is a really important research question. There are a few people, I know G. Anderson in ETH has students working on the value of FACTS control, for instance.

## Assessment of power system small signal stability based on mode shape information

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**Abstract** - This paper deals with the impact of long distance power transits on interarea oscillations in large electrical power systems. For the qualitative prediction of eigenvalues shifting caused by transits a new approach is presented. It is based on the swing profiles of the modes, which are described by the rotor mode shapes, nodes, antinodes and isolines, respectively. It is shown, that the damping of eigenvalues correlates with the orientation of the load flow to the nodes and antinodes within the corresponding rotor mode shapes. Transits from generators located in antinode areas to nodes may improve the damping. Transits from node to antinode may worsen the damping. Several load flow scenarios are calculated in the European interconnected power system to demonstrate the applicability of the proposed method to the most important interarea modes

**Keywords :** interarea-oscillations; small-signal stability; stability assessment; modal analysis

### 1 Introduction

With the deregulation of the European electric power market a competitive situation for the market participants arose. Long-distance power transits from regions with surplus generation are taking place to meet the demand in other regions, whereas economical aspects are playing a dominant role. The variation of the load flow in a wide range may lead to dangerous situations, in which the small signal stability is lost and inter-area oscillations, affecting the whole interconnected power system, occur. Such oscillations in a range of 0.15-0.3 Hz have been recorded in the European Interconnected Power System many times with a Wide Area Measurements System (WAMS) installed in different network parts [5]. Figures 1 and 2 show two examples. It is to see from Fig. 1, that the generators of Spain and France on the one side, those of Poland and Hungary on the other side are swinging against each other, whereas Germany participates on the frequency swings only marginal. However, the oscillating power over the interconnections in Germany is high, because Germany is located between the both swinging network parts. Fig. 2 shows a slow damped system behavior following the loss of active power generation in Spain. A first analysis of the frequency curve results in the assumption, that the behavior is dominated by more than one interarea modes, because of the beat effects observable in the records. The phenomena was investigated in many simulation studies, carried out in Germany and other European countries as well [1]-[6]. For this purpose a dynamic model of the entire system has been created consisting of hundreds of generators, thousands of lines and nodes. The measurements were used for verification of the models. Two techniques have been applied for the analysis. On the one side simulations have been carried out in the time domain. On the other hand the modal analysis has been applied at the first time for the entire European interconnected power system.

Because the registered oscillations occurred when increased power transits occurred in the network, one of the objectives was to investigate the impact of long distance power transits on the damping of interarea oscillations. Various studies have shown, that the limits for transits are determined by oscillatory stability rather than by the load flows.

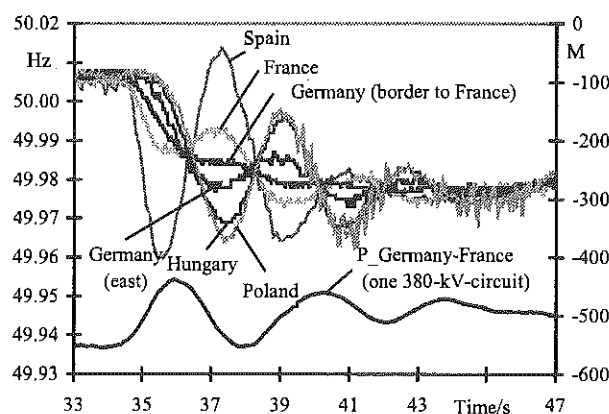


Figure 1 Behavior of the European electric power system following a loss of 900 MW generation power <sup>1)</sup>

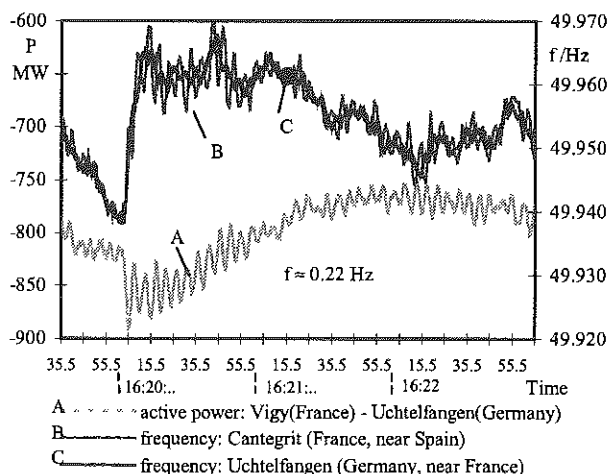


Figure 2 Interarea oscillations after 487 MW load rejection in Spain <sup>1)</sup>

Therefore, for a secure system operation it is necessary to assess the impact of transits on the oscillatory stability before the transits will be realized. However, for an online application the available analysis and simulation methods are

<sup>1)</sup> The measurements were made available for presentation by the German electric power company RWE Essen

not practicable in consequence of their complexity and the computational requirements. Furthermore, the dispatchers have to make decisions quickly.

In our paper, we will present a method for a fast assessment of the impact of power transits using information inherent in mode shapes. The method does not require a calculation directly. However, it bases on the profiles of the interarea modes described by mode shapes, which must be available for an assessment in graphical form.

In the next chapter some theoretical basics to small signal stability of linear systems will be presented, which are necessary for a better understanding of the method.

## 2 Small Signal Stability

The dynamic behavior of electrical power systems can be described by a set of algebraic and differential equations. Since the system order can reach several thousand, it is advisable to formulate the equations in the state space form. For small perturbation around the operating point the equations can be linearized. Thus we get:

$$\Delta \dot{\mathbf{x}} = \mathbf{A} \Delta \mathbf{x} + \mathbf{B} \Delta \mathbf{u} \quad (1)$$

where

$\mathbf{x}$  is the state vector describing the dynamic system elements  
 $\mathbf{A}$  is the state matrix  
 $\mathbf{u}$  is the disturbance vector containing in the rule the reference values of regulators

Real disturbances in power systems, like faults, line or load switchings are affecting the system matrix in consequence. The small signal stability considers an undisturbed system. An unstable operating point is given, when the system states, caused by an infinitely small excitation, are moving away from the steady state point aperiodically or oscillatory without getting a new stable operating point.

The state solution of Eq. (1) can be expressed as a sum of all modal contributions:

$$\Delta \mathbf{x}(t) = \sum_{i=1}^n \mathbf{c}_i e^{\lambda_i t} \mathbf{u}_i \quad (2a)$$

$$\mathbf{c}_i = \mathbf{v}_i^T \mathbf{x}(0) \quad (2b)$$

where

$\lambda_i = \sigma_i$  or  $\lambda_i = \sigma_i \pm j\omega_i$  real or complex eigenvalue  
 $\mathbf{u}_i$  right eigenvector associated with  $\lambda_i$   
 $\mathbf{v}_i$  left eigenvector associated with  $\lambda_i$   
 $\mathbf{x}(0)$  initial state condition at  $t=0$

The eigenvalues are either real or conjugate complex. It is obvious, that for a stable system behavior eigenvalues must have negative real parts. Conjugate complex eigenvalue pairs form an increased or decreased swing, depending on the real part of eigenvalue. They are called system swing modes

$$z_i(t) = e^{\sigma_i t} \sin(\omega_i t + \phi_i) \quad (3)$$

The damping ratio

$$D = \frac{-\sigma}{\sqrt{\sigma^2 + \omega^2}} \quad (4)$$

describes the damping independently from the frequency  $f = \omega/2\pi$ .

It follows from Eq. (4) that the complex right eigenvector  $\mathbf{u}_i$  is providing information about the relative activity of the state variables when the  $i$ -th system mode is excited, whereas the left eigenvector is referring to the initial conditions.

The idea of the proposed assessment method is based on the rotor mode shape, which is the graphical representation of the corresponding elements of the right eigenvector  $\mathbf{u}_i$  to one of the both mechanical rotor states. The mode shape describes the mechanical motion of generators relating to their mutual swing intensity and phase relationships. It refers always only to one particular mode. In the following, mode shapes will be described more detailed in connection with the examples presented in the next sections.

## 3 Impact of long distance power transits on the Small Signal Stability

At first, a three-machine longitudinal network should be investigated (see Fig. 3).

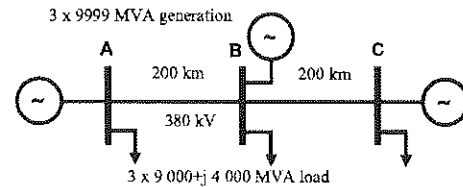


Figure 3 Three-machine test network

The system has two electromechanical modes. The root loci of eigenvalues regarding power transits between the nodes A-B, B-C and A-C are shown in Fig. 4.

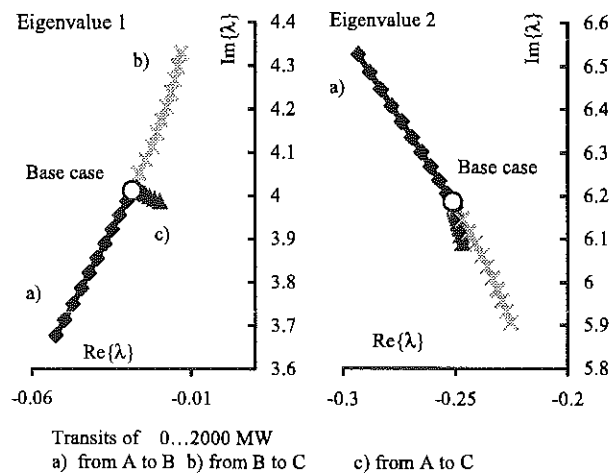


Figure 4 Root Loci of eigenvalues by varying power transits (Three-machine test network)

The damping of both modes is depicted in Fig. 5 as a function of active power transits.

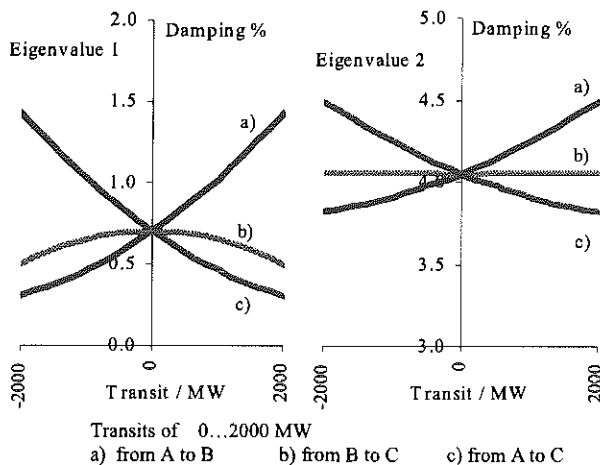


Figure 5 Dependency of damping on active power transit (Three-machine test network)

The different scenarios are calculated by varying the number of running generators. Because the loads were kept constant, the generated power in the three locations varied, too. These conditions result in active power flows between the stations, whereas the reactive power was generated locally according to constant generator voltages.

Analyzing the effect of transits on the eigenvalues, the following conclusions may be drawn.

- Transits from the border to the center shift the eigenvalues to better damping. In case of transits from the center to the border the effect is opposite.
- Transits between two border nodes have no significant effects on the eigenvalues.

In the considered three-machine test network the definition of border and center is easy. However, in a multi-machine system it could be difficult taking into consideration that the terms center and border describe swing quantities, which are not necessarily identical with geographical locations. A better insight into the problem will be possible with the help of rotor mode shapes. In Fig. 6 and 7 the mode shapes are depicted for both eigenvalues. Furthermore, we have calculated characteristic load flow scenarios to show the distortion of mode shapes caused by transactions. To find the swing axis, the vectors of the mode shape are connected with lines. The cross points on the tie lines mark locations where the swing intensity is zero. The method is only applicable to the particular network depicted in Fig. 3. However, it allows to demonstrate, that these points corresponding with the linguistic term centre can be located in different nodes, which are existing as a rule only virtually. From this it follows, that every mode has different swing centres. Besides that, several centres can exist to each mode, to see e.g. for mode 2 in Fig. 7. The centres are not fixed. Changing operating points could shift them.

For generalising our conclusions, a six-machine symmetrical system (Fig. 8) should be investigated in the following.

Within this system, 5 electromechanical modes occur (see Tab. 1). The rotor mode shapes for the base cases are depicted in Fig. 9.

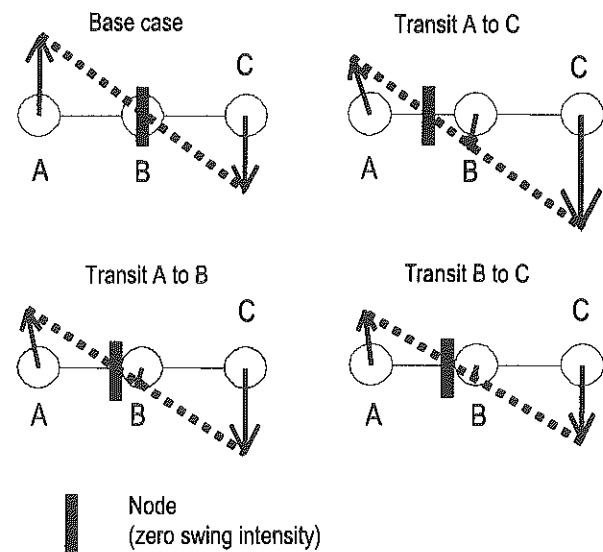


Figure 6: Mode shapes of eigenvalue 1 (three-generator test system)

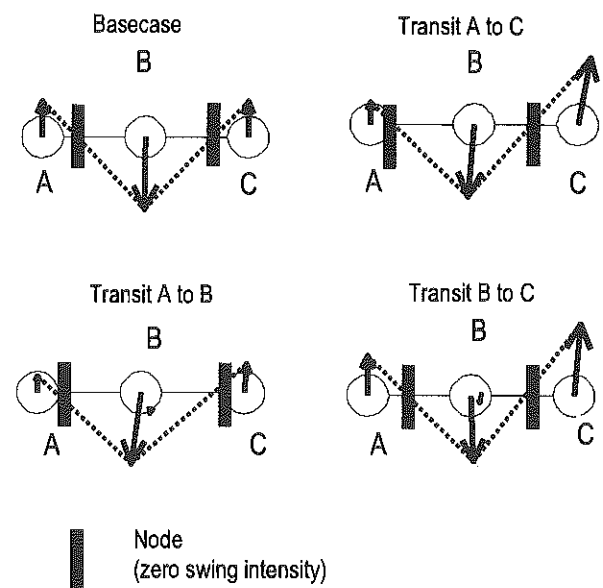


Figure 7: Mode shapes of eigenvalue 2 (three-generator test system)

Analogously to mechanical systems, the mode shapes allow to define nodes and antinodes, which are points with zero and highest swing intensity, respectively. However, such points must not exist as real nodes. Therefore we use a spline function to include isolines also describing the space between real nodes and lines. The result is the visualized geography of the swing, described by mountains (antinodes) and valleys (nodes). In this way we create the swing profile of each node (see Fig. 9). Mode 1 e.g., describes a swing of the three upper generators against the lower three ones, whereas the node line lies horizontally between both generator groups.



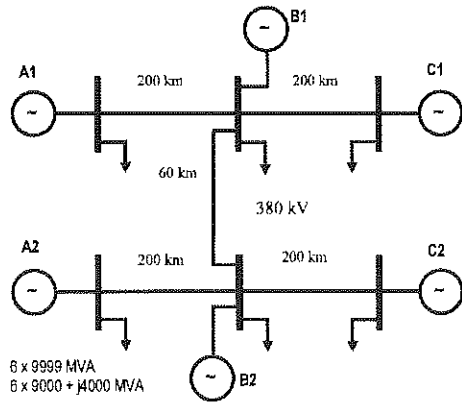


Figure 8 Six-generator test system

Table 1 Eigenvalues of the six-generator test system

| Mode | Eigenvalue[1/s]   | f [Hz]  | Damping [%] | Swing profile |
|------|-------------------|---------|-------------|---------------|
| 1    | -0.002859+3.5517i | 0.56527 | 0.08049     | ABC1↔ABC2     |
| 2    | -0.030133+4.0216i | 0.64005 | 0.74927     | A1↔C1         |
| 3    | -0.030133+4.0216i | 0.64005 | 0.74927     | A2↔C2         |
| 4    | -0.24925+6.1759i  | 0.98292 | 4.0326      | B12↔AC1/AC2   |
| 5    | -0.68877+8.7858i  | 1.39834 | 7.8156      | B1↔B2         |

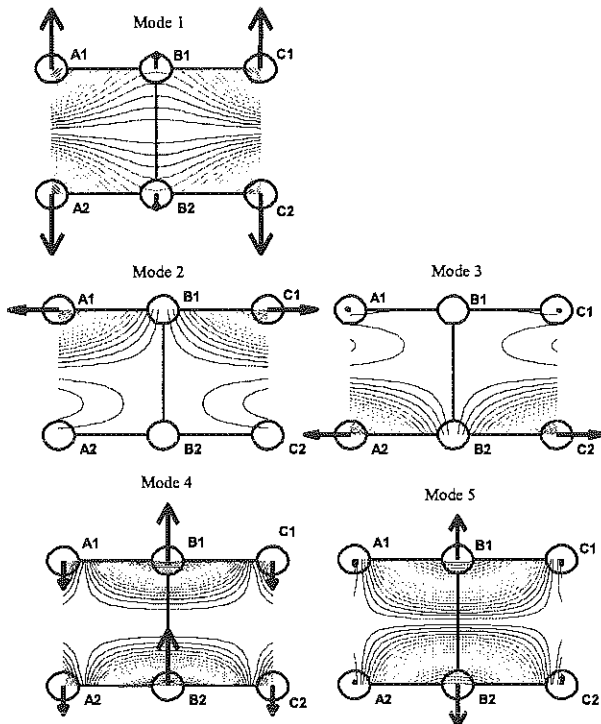


Figure 9 Profile of the five electromechanical swings in six-generator test system

In the following the correlation between nodes and antinodes on the one side and the orientation of power transits on the other side will be investigated. For this purpose we realize transits in different directions in the six-machine test network in the range of 0 up to 2000 MW.

Power transits can distort the swing profiles. The effect is demonstrated in Fig. 10 for the first and slowest mode. The isolines are shifted by the transits, so that the participation of generator C2 on the swing will be reduced significantly. The

impact of power transits on the eigenvalue 1 is given in Fig. 11. It can be seen, that the transactions from bus A2 to B2 and A2 to C2, respectively improve the damping of mode 1. The direction of both transits is still from antinode to node (see Fig. 10).

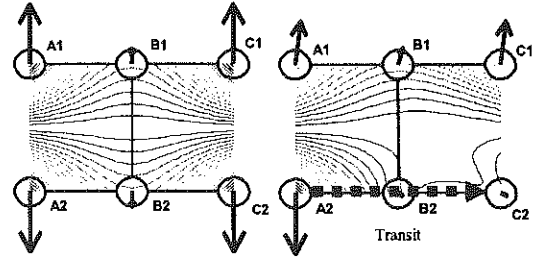


Figure 10 Mode shape and isolines of Mode 1 without and with transit from A2 to C2

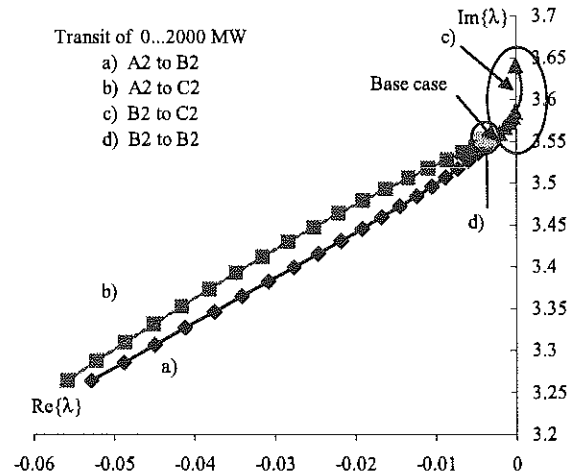


Figure 11 Shift of Eigenvalue 1 by power transits

The transit from bus bar B2 to C2 leads to a poor damping, and even a transit around 1000 MW causes an undamped motion of the system characterized by negative damping of  $D=-0.02\%$ . A transit from bus B2 to B1 leaves the damping of the underlying eigenvalue of the swing almost unchanged. Based on several case studies carried out in different network we have always found a clear correlation between the direction of power transits and the location of nodes and antinodes. The conclusions can be summarized as follow:

- Power transits from antinodes to nodes are going to improve the damping of the corresponding swings.
- Power transits from the nodes to antinodes move eigenvalues to a poor damping.
- The effects a) and b) are increasing with weak interconnections.
- In the case of transits from antinodes to antinodes, both effects compensate each other. Due to the nonlinear effects, the shifting of eigenvalues cannot be predicted clearly.
- Power transits along isolines have no significant effect on the damping of modes

Additionally, it should be emphasized, that power transits might impact the mode shape itself. In this case, the situation has to be reclassified.

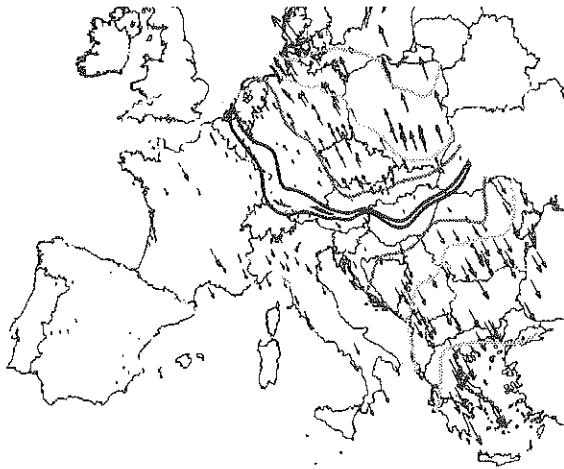


Figure 12 Mode shape and isolines of North-South Mode

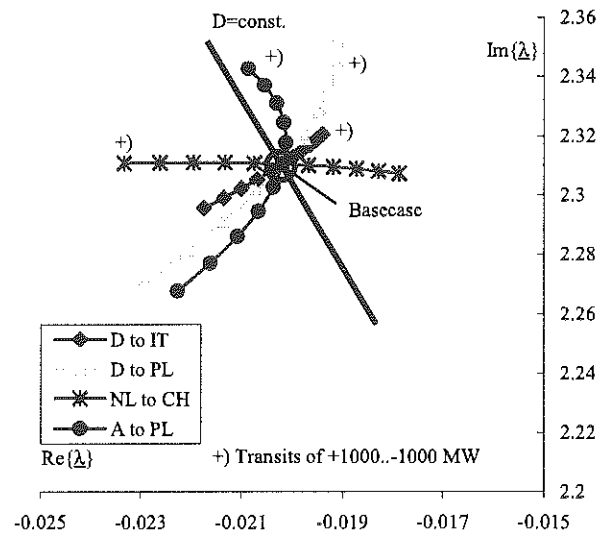


Figure 13 Shift of the eigenvalue of North-South Mode

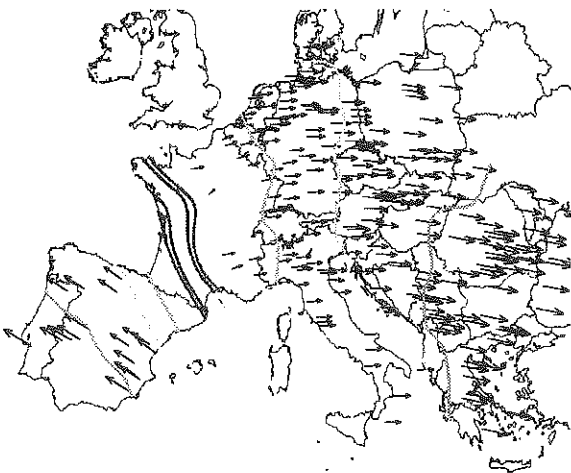


Figure 14 Mode shape and isolines of Global Mode 1

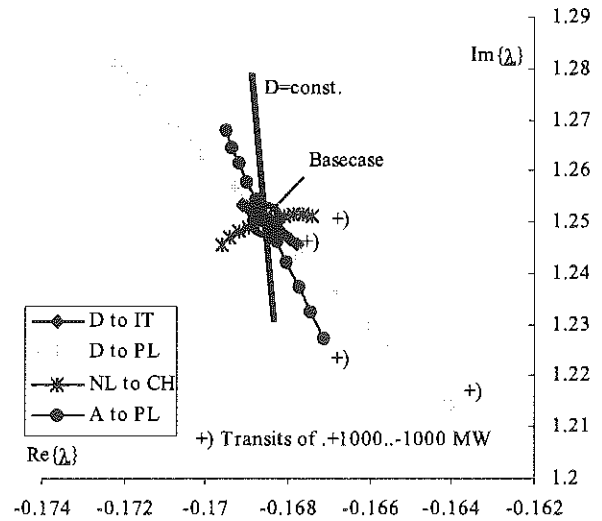


Figure 15 Shift of the eigenvalue of Global Mode 1

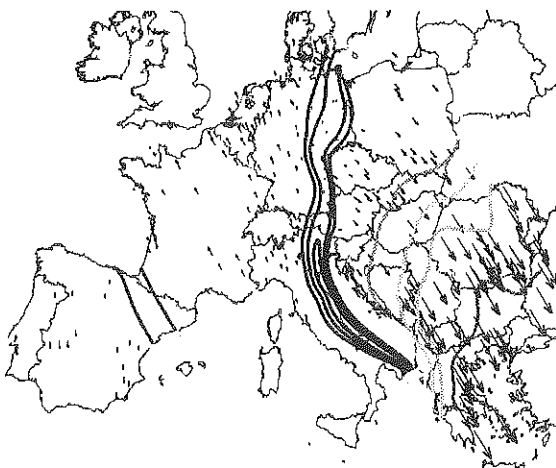


Figure 16 Mode shape and isolines of Global Mode 2

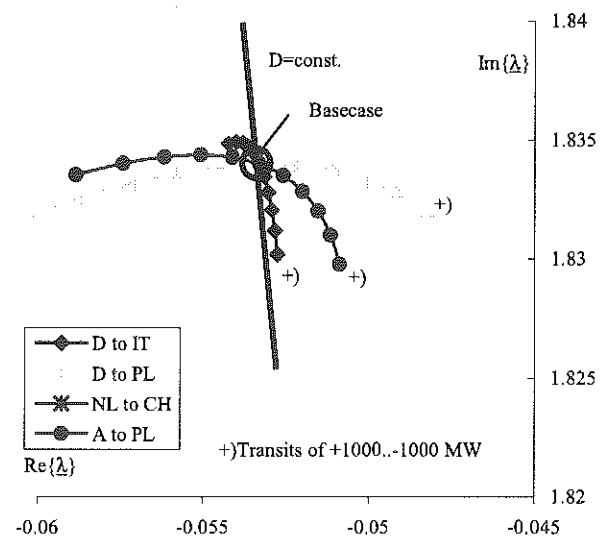


Figure 17 Shift of the eigenvalue of Global Mode 2

#### 4 UCTE/CENTREL Power System

To validate the rules in a large interconnected power system, a realistic model of the UCTE/CENREL power system, consisting of 2097 transmission lines and 464 synchronous generators with governors and excitation control models, has been used. Loads are modeled with their voltage and frequency dependencies. To force realistic transit scenarios, we have increased the power generation in some network parts and decreased it in other parts, which should receive power. Reactive power transits have not taken place.

It should be emphasized, that our European test network describes a hypothetical future state, which has been generated for theoretical investigations without considering real developments. Therefore, all examples calculated in this study, must not necessarily meet real scenarios.

Using modal analysis we have found three critical interarea eigenvalues for the described network. The first one is the North-South swing in the eastern part of the network with a frequency around  $f=0.36\text{Hz}$  (Fig. 12). The second important eigenvalue characterizes the swing of the coherent generator groups of Spain against the whole interconnected system (Fig. 13). The frequency of this global mode 1 is very low with  $f=0.19\text{Hz}$ . The third mode represents the swing of the Balkan network against the middle and western parts which is also called global mode 2 with  $f=0.26\text{Hz}$  (Fig. 14). It is characterized by the occurrence of two node lines at the border between Poland and Germany and between France and Spain, too. We have calculated a large number of transit scenarios in this network. The results as root loci of the three selected eigenvalues are shown in Figures 14-16. The transits take place in the middle and east area, because this part is modeled in detail. In the western network area mainly equivalent generators are used, whose geographical position is unknown. Furthermore, the swing profile of a few very large units does not necessarily reflect real states. Therefore, transits in the western area are not investigated.

Comparing the orientation of the transits and the shifting of eigenvalues, it can be recognized, that the rules developed in the previous section are fulfilled also in the European network. However, the effects can be quantitatively very different. A possible explanation for this could be, that the geographical distance is not matching the electrical distance in each case. However, important for the system behavior is only the electrical distance, i.e. the strength of connection. From this it follows, that the applicability of the proposed method will be better with homogenous system structures.

The quantitative impact of transits depends on other factors like voltage level, stress of the transit route, generators excitation level etc., too. However, in all scenarios we have investigated, the effects of active power transits have met the above rules. It seems to be an excellent method to predict the impact of intended power transits regarding interarea oscillations. It allows also the consideration of different modes separately.

#### 5 Conclusions

In the face of a deregulated energy market, the dynamic security of the European interconnected power system demands more emphasis on planned power transits. Within this study it was shown, that long-distance power transits cause a shifting of the frequency and damping of the power system eigenvalues. Low damping has to be avoided because of the increasing risk of the occurrence of interarea oscillations.

For the decision-making in dispatch centers, a method using the information in form of the graphical representation of the mode shapes of critical interarea modes is presented. The shifting of the eigenvalues depends on the orientation of power transits to the nodes and antinodes. Because the locations of nodes and antinodes of a swing are known in advance, the qualitative impact of power transits to the shift of the underlying eigenvalues becomes predictable. However, further investigations must be carried out to quantify the impact of power transits.

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## Voltage Reactive Power Control Using NAS Battery System

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### Introduction

In recent years, the power demand in most countries has considerably increased, and tends to be concentrated in urban areas. The long distance and deviated location of large power sources deteriorate the availability of power facilities. The power demand differences between day and night or summer and winter worsen the load factor. Additionally, resource exhaustion and environmental disruption with use of fossil fuels have focused social attention, and countermeasures are also crucial. For these reasons, it is imperative to allocate energy storage systems, which have superior environmental characteristics, in distribution substations in the vicinity of power demand areas for using the power facilities efficiently, improving the load factor and protecting the environment.

Energy storage batteries, SMES devices (Superconducting Magnetic Energy Storage devices), flywheel devices, compressed air storage devices, and so on have been proposed for the energy storage systems. These systems can store electric energy by converting it to chemical energy, magnetic energy, kinetic energy and pressure energy, respectively. In these systems, the energy storage batteries seem to be most practical for reasons of technical perfection at present and easiness of allocation in urban areas. Especially, NAS battery (Natrium Sulfur battery) is actively researched and developed as the energy storage system for the reasons that NAS battery is excellent in energy density and efficiency, and has the feature of no self-discharging characteristics with use of solid electrolyte<sup>[1]</sup>.

NAS battery system can generally respond faster than existing generator units, and can independently control active and reactive power outputs by the function of an AC-DC converter system. Also, NAS battery system can instantaneously charge and discharge the power from twice to five times as large as the rated output if the capacity of an AC-DC converter device is assumed to be large. Therefore, it has also been a hope to utilize NAS battery system for not only making good use of the power facilities and improving the load factor but also for voltage reactive power control (VQC).

In this paper, we take NAS battery system as one of the energy storage systems, and examine the possibility of voltage reactive power control using NAS battery system.

First, we consider that NAS battery system is utilized for voltage stability control, and propose a method for determining the optimal allocation and PQ output ratio of NAS battery systems in order to improve voltage stability. The method uses

a voltage stability index VIPI (Voltage Instability Proximity Index), and describes at which substations NAS battery systems should be installed and by what ratio of active and reactive powers NAS battery systems should be output. As far as a concrete way, we combine a sensitivity method with an optimal power flow calculation method. The sensitivity method can make a ranking of allocation candidate buses by carrying out a power flow computation for multiple solutions just once, and can approximately calculate the PQ output ratio at the allocation candidate buses simultaneously. The optimal power flow calculation method can obtain the optimal allocation and PQ output ratio, but it is difficult to grasp the characteristics of the allocation candidate buses for voltage stability, and to make the ranking of the allocation candidate buses. Therefore, we use a combined method for determining the allocation and PQ output ratio efficiently and optimally considering the features of both the methods.

Next, we consider that NAS battery system is utilized for dynamic voltage control, and propose a method for suppressing voltage fluctuation caused by a system accident, and so on. The method calculates voltage sensitivities, and describes that voltage fluctuation is effectively settled by using the ratio of active and reactive power outputs obtained from the voltage sensitivities.

By carrying out simulations using example system models, we verify the validity of the proposed static and dynamic methods, and show the multi-functional characteristics of NAS battery system. At the same time, we evaluate the performance and/or specifications of NAS battery system for achieving voltage reactive power control.

### NAS Battery

#### *Principle and Features of NAS Battery<sup>[2][3]</sup>*

Ford Motor Company, USA published the principle of NAS battery in 1966, and since then NAS battery has been actively researched and developed for electric vehicles. The basic composition of NAS battery is shown in Fig.1. NAS battery has fused sodium as a cathode-active material, and has fused sulfur and sodium polysulfide as an anode-active material, and uses a solid electrolyte, which conducts sodium ions selectively, as an electrolyte. The solid electrolyte is generally composed by glass or ceramics. Especially, because beta alumina ( $\text{Na}_2\text{O} \cdot \text{Al}_2\text{O}_3$ ) conducts sodium ions very well, most NAS batteries, which are now developed, use beta alumina as the electrolyte. Besides, because beta alumina does not have electron conductivity, it also plays the role of separating the

anode and cathode. The anode-active material is soaked in a conductive material in order to help the transfer of electrons according to the electrochemical reaction. It is necessary that NAS battery keep all the active materials fused, and it is usually used under a high temperature of  $300 \sim 350$  [°C] to optimize ionic conduction of beta alumina.

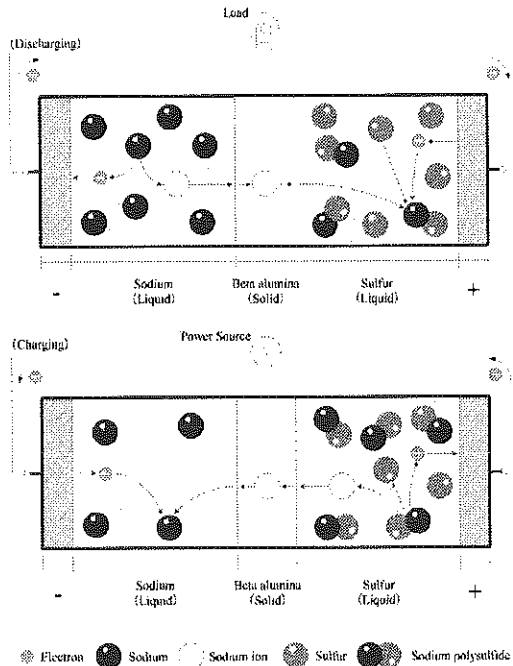


Fig.1 Mechanism chart of charging and discharging

NAS battery has the following features.

- 1) It is possible to allocate it compactly in distribution systems or power demand areas, and it has about three times as high energy density as a lead battery.
- 2) It can store energy effectively, because it has high charging and discharging efficiency, and there are no self-discharging characteristics.
- 3) It is very safe, and does not need maintenance for operation, because it is a battery that has a completely closed structure.
- 4) There is no life expectancy constraint with use of active materials, because the active materials are liquid.
- 5) The capacity decrease against high discharging efficiency is extremely small.
- 6) It has excellent durability, because main composition parts are inorganic materials,
- 7) Incidental facilities such as external piping, pumps and valves are unnecessary.

Moreover, the electrochemical equivalents of sodium and sulfur used as the active materials are extremely frugal, and their resources are abundant and cheap. Accordingly, it can be said that NAS battery is the energy storage system, which is suited for saving energy and conserving resources.

#### Operating Control Functions of NAS Battery<sup>[2][4]</sup>

When a NAS battery is introduced in a distribution substation, we need peripherals such as an AC interface, AC-DC converter device and DC interface for the AC-DC converter system.

The AC interface receives power from the distribution system, and the power system is tied up with a DC circuit (battery system) by the AC-DC converter system. Besides, the DC interface, which provides a protection function against a breakdown, is installed between the AC-DC converter device and battery system. In addition, a monitoring measurement system and operating control system, which monitor and control the entire system, are installed. The operating control functions (operating control modes) of the entire system are shown in Table 1.

Table 1 Operating control functions

| Operating control modes      |                          | Content of control                                          |
|------------------------------|--------------------------|-------------------------------------------------------------|
| P control                    | Fixed power at AC side   | Keep active power constant at AC side.                      |
|                              | Fixed power at DC side   | Keep active power constant at DC side.                      |
|                              | Fixed current at DC side | Keep current constant at DC side.                           |
|                              | Fixed voltage at DC side | Keep voltage constant at DC side.                           |
| Q control                    | Fixed reactive power     | Keep reactive power constant.                               |
|                              | Fixed voltage            | Control reactive power to keep the system voltage constant. |
|                              | Fixed power factor       | Control reactive power to keep the power factor constant.   |
| Load following control (AFC) |                          | Output power according to the signal from the outside.      |

As to the AC-DC converter device of NAS battery, separately-excited inverter and self-excited inverter (current type or voltage type) have been used. Especially, the voltage type self-excited inverter need not reverse the polarity to charge and discharge, and can do operating control at all quadrants of PQ coordinates, that is from charging to discharging and from leading power factor to lagging power factor, by reversing the firing angle of the inverter.

#### Voltage Stability Control

In this chapter, we consider that NAS battery system is utilized for voltage stability control.

#### Outline

Most similar studies do not evaluate the optimal allocation and PQ output ratio of NAS battery systems but only the optimal allocation and capacity. However, if we do not consider the element of cost, it would be better to have as large capacity of NAS battery systems as possible. Therefore, it is important and realistic to evaluate the effective ratio of active and reactive power outputs for improving voltage stability under limited capacity. If we find that outputting reactive power is more effective than outputting active power, NAS battery system (or

AC-DC converter system) should have the specifications that can output a lot more reactive power than active power, and we can evaluate the performance that NAS battery system should have to improve voltage stability.

Thus, this paper proposes the following method. First, we make a ranking of allocation candidate buses by a sensitivity method using sensitivities for VIPI. Next, we determine the optimal allocation and PQ output ratio by an optimal power flow calculation method using VIPI.

#### Voltage Stability Index VIPI<sup>[5]</sup>

The conceptual figure of is shown in Fig.2. VIPI is defined as a cubic angle  $\theta$ , which shows how the specified value vector  $y_s$  corresponding to the present state and the critical vector  $y(a)$  corresponding to the voltage stability limit are close to each other in the specified value space. VIPI is a scalar index, and can quantitatively evaluate the voltage stability margin.

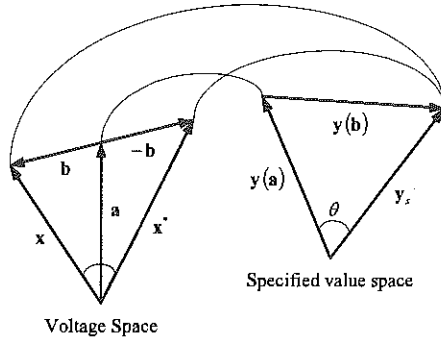


Fig.2 Conceptual figure of VIPI

The following is the explanation of Fig.2. A power flow equation can be written as follows, where  $y_s$  is the specified value vector and  $x$  the voltage vector.

$$y_s = y(x) \quad (1)$$

Now, we consider two voltage vectors  $x$  and  $x^*$  satisfying the same specified value vector  $y_s$ , where  $x$  is the voltage vector in the operating condition (higher solution vector) and  $x^*$  the voltage vector in the non-operating condition (lower solution vector). We obtain  $x$  and  $x^*$  by carrying out a power flow computation for multiple solutions, and express them by the addition and subtraction of vector  $a$  (critical vector in the voltage space) and vector  $b$  (deviation vector in the voltage space) as below.

$$x = a + b \quad x^* = a - b \quad (2)$$

Therefore,  $a$  and  $b$  can be written as follows.

$$a = \frac{x + x^*}{2} \quad b = \frac{x - x^*}{2} \quad (3)$$

Because VIPI is an angle, which is made by the specified value vector  $y_s$  and the critical vector  $y(a)$  in the specified value space, VIPI is defined as below.

$$VIPI \equiv \theta = \cos^{-1} \frac{y_s^T \cdot y(a)}{\|y_s\| \cdot \|y(a)\|} \quad (4)$$

As the power system becomes more heavily loaded, VIPI decreases and eventually becomes zero at the critical point. Also, VIPI has the feature that the decrease is observed to be almost linear. As for other voltage stability indices, the value either hardly changes or suddenly changes. Therefore, VIPI is suitable for monitoring the voltage stability margin to the critical point, and this is a very big advantage in monitoring and controlling the heavily loaded systems. Moreover, VIPI can be obtained by carrying out a power flow computation for multiple solutions just once, and also has the feature that it can be evaluated by a small amount of calculation.

#### Making Ranking of Allocation Candidate Buses

Now, we calculate sensitivities of active and reactive powers for VIPI, and examine how active and reactive power outputs of NAS battery system affect voltage stability in the entire system. Then, we propose the following synthetic index  $S_i$  using  $S_{Pi}$  and  $S_{Qi}$  for making the ranking of the allocation candidate buses.

$$S_{Pi} = \frac{dVIPI}{dP_i} \quad S_{Qi} = \frac{dVIPI}{dQ_i} \quad (5)$$

$$S_i = \sqrt{S_{Pi}^2 + S_{Qi}^2} \quad (6)$$

In order to effectively improve voltage stability, we have only to allocate NAS battery systems at the buses where  $S_i$  becomes large. To improve voltage stability most effectively takes maximum effect under the limited capacity, and leads to reducing the installation cost, the operating cost, and so on. Besides, if we allocate NAS battery systems in the order of the magnitude of  $S_i$  when NAS battery systems are allocated at two or more buses, it will be the most appropriate allocation from the viewpoint of improving voltage stability.

Moreover, we define that  $R'_i$  be the sensitivity of reactive power divided by the sensitivity of active power, and propose that  $R'_i$  be used as an approximate PQ output ratio.

$$R'_i = \frac{S_{Qi}}{S_{Pi}} \quad (7)$$

Normally, we can obtain the optimal PQ output ratio only when optimal power flow calculations are solved. However, by using  $R'_i$ , we can make the ranking of the allocation candidate buses, and can calculate the approximate PQ output ratio at the allocation candidate buses simultaneously.

#### Determining Allocation and PQ Output Ratio

In order to improve voltage stability in distribution systems, we have only to calculate the outputs of NAS battery systems with maximum VIPI under the specified capacity constraints. The variables in optimal power flow calculations are active power output  $P_{Ni}$  and reactive power output  $Q_{Ni}$ , and we will prepare the pairs of  $P_{Ni}$  and  $Q_{Ni}$  only for the allocation candidate buses. Concretely, it is proposed to solve the optimal power flow calculations considering the following objective function, equality constraints and inequality constraints.

## 1) Objective function (Maximization of VIPI)

$$\text{maximize VIPI} \quad (8)$$

## 2) Equality constraints

(Power flow equations in rectangular coordinates)

Generator buses

$$P_{si} = \sum_{j=1}^n (G_{ij}e_j e_i - B_{ij}e_j f_j + B_{ij}e_j f_i + G_{ij}f_j f_i) \quad (9)$$

$$V_{si}^2 = e_i^2 + f_i^2 \quad (10)$$

Load buses

$$P_{si} + P_{Ni} = \sum_{j=1}^n (G_{ij}e_j e_i - B_{ij}e_j f_j + B_{ij}e_j f_i + G_{ij}f_j f_i) \quad (11)$$

$$Q_{si} + Q_{Ni} = \sum_{j=1}^n (-B_{ij}e_j e_i - G_{ij}e_j f_j + G_{ij}e_j f_i - B_{ij}f_j f_i) \quad (12)$$

## 3) Inequality constraints

(Capacity constraints of NAS battery systems)

$$\sqrt{P_{Ni}^2 + Q_{Ni}^2} \leq S_{Ni}^2 \quad (\text{For each individual bus}) \quad (13)$$

$$\sum_i \sqrt{P_{Ni}^2 + Q_{Ni}^2} \leq S_N^2 \quad (\text{For the entire system}) \quad (14)$$

By solving the optimal power flow calculations above-mentioned, we can obtain the active power output  $P_{Ni}$  and reactive power output  $Q_{Ni}$  that can improve voltage stability to its maximum. Here, defining that  $R_i$  be the reactive power output divided by the active power output, we can evaluate this  $R_i$  as follows.

$$R_i = \frac{Q_{Ni}}{P_{Ni}} \quad (15)$$

If the capacity of NAS battery systems [MVA] should be distributed to the active power outputs [MW] and reactive power outputs [MVar] by using  $R_i$ , we can improve voltage stability in distribution systems most effectively.

*Algorithm of Proposed Method*

It is desirable to use the optimal power flow calculation method to carry out an accurate analysis when the optimal allocation and PQ output ratio of NAS battery systems are sought in an actual system planning or operation. However, it is difficult to grasp the characteristics of the allocation candidate buses for voltage stability even if the optimal power flow calculations are carried out. Moreover, we cannot make the ranking of the allocation candidate buses without carrying out the optimal power flow calculations by changing, with trial and error, the buses at which NAS battery systems are allocated. Therefore, we propose the following method by which the sensitivity method is combined with the optimal power flow calculation method.

Step 1 Make a ranking of the allocation candidate buses by using the sensitivity method.

Step 2 Narrow down the allocation candidate buses at which NAS batteries are actually allocated from the ranking obtained in Step 1.

Step 3 Carry out the optimal power flow calculation method after reducing the number of variables used in the optimal power flow calculations by narrowing down the allocation candidate buses.

By using this combined method, we can obtain the allocation and PQ output ratio efficiently and optimally after we grasp the characteristics of the allocation candidate buses for voltage stability.

*Numerical Examination*

We carry out simulations in order to verify the validity of the proposed method. The system model is a 73-bus distribution system shown in Fig.3. This system includes the voltage levels 147 [kV] to 3.2 [kV]. VIPI in the time section at which simulation is carried out is 2.0133 [deg], and we assume a heavily loaded system. In this simulation, it is assumed that NAS batteries may be allocated at multiple buses if the total capacity of NAS batteries does not exceed 2.0 [MVA], and that the capacity constraint for each individual bus is 1.5 [MVA].

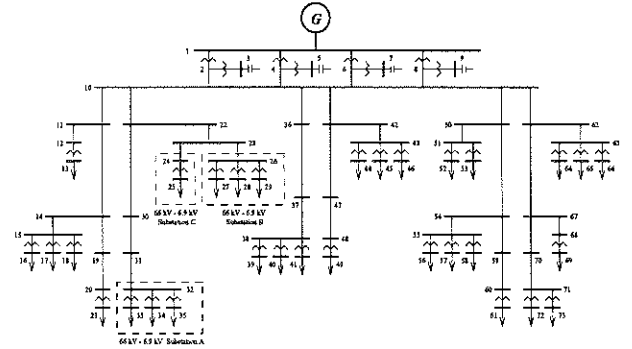


Fig.3 73-bus distribution system

First, we calculate the index  $S_i$  and approximate PQ output ratio  $R_i'$  by the sensitivity method, and line them up in the order of the magnitude of the index  $S_i$ . Here, we show the top ten buses, which have large index values of  $S_i$ , in Table 2.

Table 2 Sensitivity and approximate PQ output ratio

| Bus | Subst.  | $S_{Pi}$ | $S_{Qi}$ | $S_i$  | $R_i'$ |
|-----|---------|----------|----------|--------|--------|
| 33  | A - 2nd | 0.0777   | 0.0885   | 0.1178 | 1.1393 |
| 34  | A - 2nd | 0.0547   | 0.0605   | 0.0815 | 1.1058 |
| 35  | A - 2nd | 0.0475   | 0.0567   | 0.0740 | 1.1957 |
| 32  | A - 1st | 0.0244   | 0.0434   | 0.0498 | 1.7812 |
| 27  | B - 2nd | 0.0233   | 0.0287   | 0.0369 | 1.2326 |
| 28  | B - 2nd | 0.0232   | 0.0287   | 0.0369 | 1.2354 |
| 29  | B - 2nd | 0.0230   | 0.0280   | 0.0362 | 1.2176 |
| 25  | C - 2nd | 0.0120   | 0.0221   | 0.0251 | 1.8365 |
| 26  | B - 1st | 0.0078   | 0.0209   | 0.0223 | 2.6878 |
| 24  | C - 1st | 0.0076   | 0.0207   | 0.0221 | 2.7160 |

From Table 2, we find that the load bus at which the index  $S_i$  becomes maximum, and the optimal installation bus of NAS battery system is bus 33, that is to say, the secondary side (6.9 [kV] side) at the substation A. Besides, we also find that the approximate PQ output ratio  $R_i$  at that time is 1.1393, and thus the output ratio P:Q should be adjusted to 1:1.1393.

Next, the allocation candidate buses are narrowed down to three buses (secondary side at the substation A, bus 33, 34, 35) by the result of Table 2. Here, we carry out the optimal power flow calculation considering active power output  $P_{Ni}$  and reactive power output  $Q_{Ni}$  as the variables, and calculate VIPI and the optimal PQ output ratio  $R_i$ , and line them up in the order of the magnitude of the capacity  $S_{Ni}$ . The results are shown in Table 3.

Table 3 Capacity and optimal PQ output ratio

| Bus | Subst. | $P_{Ni}$ [MW] | $Q_{Ni}$ [MVar] | $S_{Ni}$ [MVA] | $R_i$  |
|-----|--------|---------------|-----------------|----------------|--------|
| 33  | A-2nd  | 0.9753        | 1.1397          | 1.5000         | 1.1685 |
| 34  | A-2nd  | 0.3376        | 0.3688          | 0.5000         | 1.0926 |
| 35  | A-2nd  | 0.0000        | 0.0000          | 0.0000         | –      |

Maximum VIPI = 3.2503 [deg]

From Table 3, we find that VIPI is increased from 2.0133 [deg] to 3.2503 [deg], and voltage stability in the entire system is also improved.

The results show that as much of the capacity as possible is concentrated at bus 33, which has the largest sensitivity, and the rest of the capacity is installed at bus 34, which has the next largest sensitivity. Therefore, we can determine the allocation and PQ output ratio efficiently and optimally if we carry out the sensitivity method for picking some allocation candidate buses and the optimal power flow calculation method after reducing the number of the allocation candidate buses. Moreover, it saves the calculation effort for system planners and operators to narrow down the allocation candidate buses.

### Dynamic Voltage Control

In this chapter, we consider that NAS battery system is utilized for dynamic voltage control.

#### Outline

If bus voltages are terribly dropped by a system accident, and so on, NAS battery systems, which are connected to these buses, are generally suspended. However, if we use voltage type self-excited inverters as AC-DC converter devices of NAS battery systems, NAS battery systems can continue operating control even if a system accident is happened. Moreover, if we carry out appropriate operating control by NAS battery systems, it is considered to be able to reduce the influence of a system accident.

Thus, this paper proposes the method which NAS battery systems output the power larger than the rated output, and suppress a severe voltage fluctuation caused by a three-phase ground fault, and so on.

#### Algorithm of Proposed Method

First, we prepare the system, which periodically calculates sensitivities of active power  $P_i$  and reactive power  $Q_i$  for voltage  $V_i$  at the bus  $i$  where NAS battery system is installed, that is to say, calculates  $dV_i / dP_i$  and  $dV_i / dQ_i$ , and we get the ratio of active and reactive power outputs of NAS battery system ready beforehand. Next, we prepare the system, which samples instantaneous voltages at the bus where NAS battery system is installed, and we calculate effective (RMS : Root Mean Square) voltages at the bus every one cycle. If a terrible voltage fluctuation is recognized between two cycles ago and one cycle ago, we consider that NAS battery system effectively suppresses the voltage fluctuation by controlling active and reactive power outputs using the ratio of the voltage sensitivities. The concrete algorithm is as follows.

Step 1 By sampling instantaneous voltages and calculating effective voltages at the bus where NAS battery system is installed, voltage difference  $\Delta V_i$  between two cycles ago and one cycle ago is evaluated.

Step 2 By multiplying the voltage difference by appropriate gain  $k_i$ , controlled variable of apparent power  $\Delta S_{Ci}$  is calculated.

$$\Delta S_{Ci} = k_i \cdot \Delta V_i \quad (16)$$

Step 3 By using the voltage sensitivity  $dV_i / dP_i$  and  $dV_i / dQ_i$  which are prepared beforehand, the controlled variable of apparent power  $\Delta S_{Ci}$  is shared to controlled variables of active power  $\Delta P_{Ci}$  and reactive power  $\Delta Q_{Ci}$ .

$$\Delta P_{Ci} = \frac{dV_i / dP_i}{\sqrt{(dV_i / dP_i)^2 + (dV_i / dQ_i)^2}} \cdot \Delta S_{Ci} \quad (17)$$

$$\Delta Q_{Ci} = \frac{dV_i / dQ_i}{\sqrt{(dV_i / dP_i)^2 + (dV_i / dQ_i)^2}} \cdot \Delta S_{Ci} \quad (18)$$

Step 4 If the sum of the rated outputs ( $P_{Ri}$ ,  $Q_{Ri}$ ) and the controlled variables ( $\Delta P_{Ci}$ ,  $\Delta Q_{Ci}$ ) exceed the twice rated output ( $2S_{Ri}$ ), the controlled variables are revised by calculating appropriate multiplier  $r_i$  ( $0 \leq r_i \leq 1$ ).

$$\Delta P_{Ci} \rightarrow r_i \cdot \Delta P_{Ci} \quad (19)$$

$$\Delta Q_{Ci} \rightarrow r_i \cdot \Delta Q_{Ci} \quad (20)$$

Where  $r_i$  is revision multiplier of the controlled variables which satisfies  $(P_{Ri} + r_i \Delta P_{Ci})^2 + (Q_{Ri} + r_i \Delta Q_{Ci})^2 = (2S_{Ri})^2$  and  $0 \leq r_i \leq 1$ .

Step 5 By adding the rated output ( $P_{Ri}$ ,  $Q_{Ri}$ ) and the controlled variables ( $\Delta P_{Ci}$ ,  $\Delta Q_{Ci}$ ), outputs of NAS battery system are determined.

$$P_{Ni} = P_{Ri} + \Delta P_{Ci} \quad (21)$$

$$Q_{Ni} = Q_{Ri} + \Delta Q_{Ci} \quad (22)$$

Step 6 50 [msec] delay is considered for the outputs of NAS battery system which are determined above.



### Numerical Examination

We carry out simulations in order to verify the validity of the proposed method. The system model is a 3-bus 9-machine system shown in Fig.4. NAS battery system is installed at bus 6, and the rated output is 0.1 [p.u.] (about one tenth of the demand at bus 6).

In this paper, we assume the case that an one-circuit three-phase ground fault is caused near bus 5 on transmission line 5-7, the one circuit is opened 70 [msec] later, and the one circuit is reclosed 2 [sec] further on.

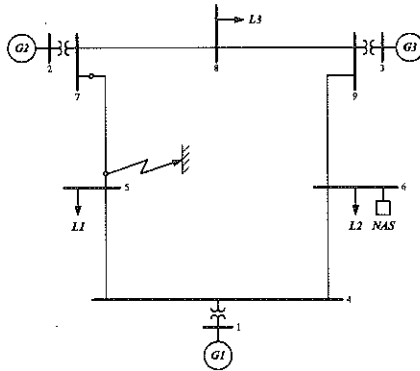


Fig.4 3-machine 9-bus system model

Before the fault, NAS battery system is operated in the rated outputs that are  $P_R = 0.1$  [p.u.] and  $Q_R = 0.0$  [p.u.], and the voltage sensitivities at bus 6 are  $dV/dP = 0.0621$  and  $dV/dQ = 0.4366$ . After the fault, the output, which NAS battery system can control, is up to 0.2 [p.u.], and the gain, which calculates the controlled variable of apparent power from the voltage difference, is  $k = 100$ . This gain is the value such that NAS battery system outputs the power of 1 [p.u.] in the case that a voltage drop of 1 [p.u.] is caused in 1 [sec].

First, we compare the case with control and the case without control by NAS battery system, and show the voltage fluctuation at bus 6 in Fig.5. Next, we show the control of NAS battery system for suppressing the voltage fluctuation in Fig.6.

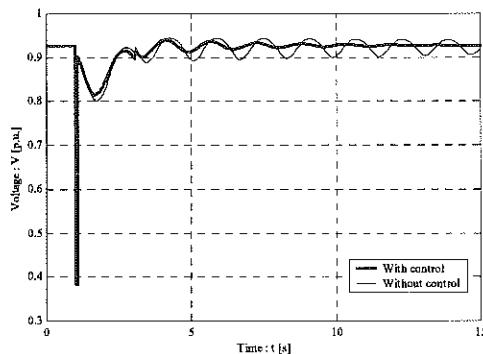


Fig.5 Voltage fluctuation at bus 6

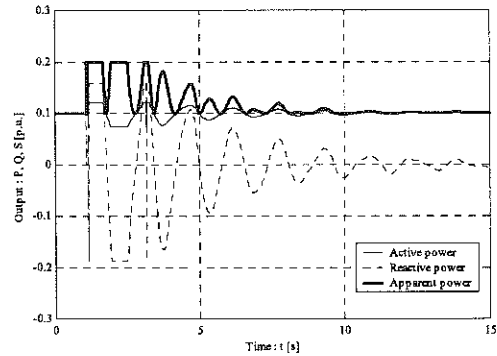


Fig.6 Control of NAS battery system

From Fig.5 and 6, we find that the voltage fluctuation is effectively suppressed by controlling active and reactive power outputs of NAS battery system using the ratio of the voltage sensitivities.

### Conclusions

In this paper, we have taken NAS battery system as one of energy storage systems, and have examined the possibility of voltage reactive power control using NAS battery system. As examples, we have proposed to utilize NAS battery system for voltage stability control and dynamic voltage control, and have shown the multi-functional characteristics of NAS battery system.

In the case of using NAS battery system for voltage reactive power control, we have found that NAS battery system should output a lot more reactive power than active power. The majority of NAS battery systems being now developed are operated experimentally with a power factor of 1.0, and reactive power output is about several percent of active power even when reactive power can be output. Therefore, it is necessary in real use to modify the specifications for AC-DC converter systems, which regulate active and reactive power outputs.

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## Evaluation of Background Oscillation in Power System on Analog Power System Simulator

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**Abstract:** In order to investigate the effects of background oscillations on power system stability, analog simulator tests have been performed on the Analog Power System Simulator at the Research Laboratory of the Kyushu Electric Power Co. A longitudinal four-machine infinite bus system has been utilized as a study system to investigate the propagation of injected background oscillations into the study system. Propagated background oscillations clearly indicate the stability level of the study system, therefore, the proposed investigation is quite valuable for the development of real time stability monitoring systems.

**Keywords:** Background oscillations, real time stability monitoring, analog simulator, propagation of oscillations.

### I. Introduction

Due to the increasing size and complexity of electric power systems, and also due to the high rate of growth of electric power demand, electric power systems are often operated in a lower stability margin. Therefore, the real time stability monitoring is one of the major subjects for the power system operation[1-5].

It is well known that the excitation control is one of the effective means to improve the damping of poorly damped oscillations[6]. In actual power systems, there always exist low-frequency global mode of background oscillations caused by the unbalance between power generation and unpredictable variation of power demand. When the power systems are operated under a lower stability margin, the background oscillations[5] may cause instability under specific situations. In order to investigate the effects of background oscillations on power system stability, analog simulator tests have been performed on the Analog Power System Simulator[6] at the Research Laboratory of the Kyushu Electric Power Co. A longitudinal four-machine infinite bus system has been utilized as a study system to investigate the propagation of injected background oscillations into the study system.

### II. Study System

Fig. 1 illustrates the basic configuration of a three-area system. The three-area system has two external systems as shown in the figure. Background oscillations are injected from the External System I to the study system and propagated through the study system into the External System II. Through the propagation of background oscillations, the stability of the study system can be evaluated.

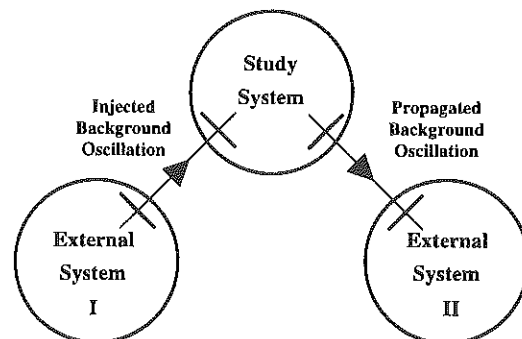


Fig. 1. Basic Configuration of Three-Area System

Fig. 2 illustrates the configuration of a study system. The study system is a longitudinal four-machine system. In Fig. 2, the background oscillation generator represents the External System I and the infinite bus represents the External System II. The study system was set on the Analog Power System Simulator at the Research Laboratory of the Kyushu Electric Power Co. Background oscillations were injected to the study system through current amplifiers as shown in Fig. 2, and real power flows were monitored at several locations in the study system to investigate the propagation of the background oscillations into the study system. The background oscillation generator injected real power oscillations based on the background oscillations actually measured on one of the 500kV trunk lines in the Kyushu Electric Power System.

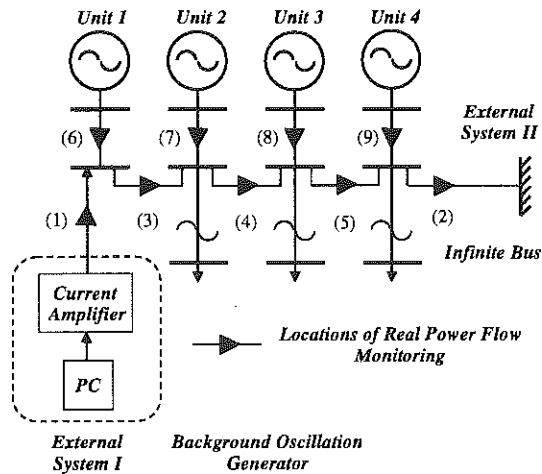


Fig. 2. Four Machine Infinite Bus Study System

The study system has two oscillation modes: local mode around 1Hz for each corresponding unit, and a low-frequency inter-area global mode around 0.3Hz. In the study system the instability is detected on the global mode[6].

For the analog simulator tests, a personal computer based background oscillation generator module was also set up as shown in Fig. 3. Fig. 3 shows the basic configuration of the background oscillation generator. In Fig. 3,  $V_a$ ,  $V_b$ , and  $V_c$  are the three-phase voltages at the location of the background oscillation generator, and  $I_{as}$ ,  $I_{bs}$ , and  $I_{cs}$  give the three-phase instantaneous currents injected from the background oscillation generator to the study system on the Analog Power System Simulator. To specify these current levels, real power flow signals measured on a 500kV trunk line were utilized. Namely the gain  $k$  was modified considering the level of background oscillations measured on the trunk line. When  $k$  has a positive value, then the real power is injected from the background oscillation generator to the study system. On the contrary, for a negative  $k$ , the real power is absorbed from the study system by the background oscillation generator.

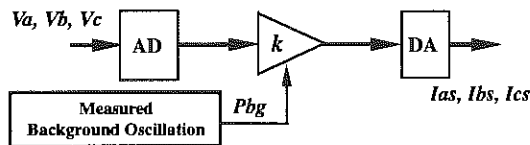


Fig. 3. Basic Configuration of Background Oscillation Generator Module

The module was developed in the Matlab/Simulink environment. For the real time operation of the module, a DSP, installed in the personal computer, was utilized. In addition, AD and DA conversion interfaces are required for the interface between the background oscillation generator and the Analog Power System Simulator. For the injection of the

three-phase currents, current amplifiers are required as shown in Fig. 2.

The analog simulator tests were performed subject to normal conditions and a faulted condition, where a three-phase to ground fault at the point A shown in Fig. 4 in the study system following the isolation of the faulted line after four cycles. In addition, during the tests, all the settings of the real power output from Unit 2 to Unit 4 were fixed to 0.6 pu. Only the real power output setting of Unit 1 was modified from 0.2 pu to 0.4 pu to investigate the relation between the stability level and the propagated background oscillations.

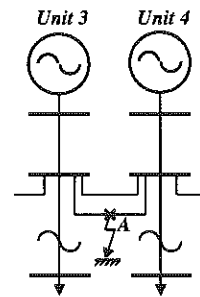


Fig. 4. Three-Phase to Ground Fault

Fig. 5 shows the overview of the Analog Power System Simulator during the testing. The personal computer based background oscillation generator is connected to the Analog Power System Simulator through the current amplifiers.

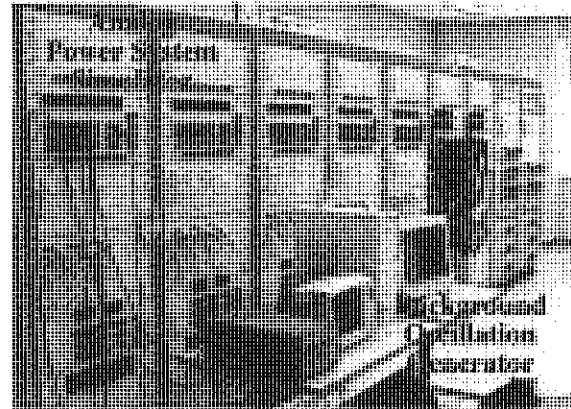


Fig. 5. Overview of Analog Power System Simulator

### III. Results of Analog Simulator Tests

The analog simulator tests were performed to investigate the propagation of background oscillations injected to the study four-machine system and also to investigate the stability of the study system. To improve the stability of the study system, several situations were considered for the application of power

system stabilizers(PSS). Table I shows the implementations of PSSs on the units in the study system, where CPSS indicates a conventional PSS and FLPSS indicates a fuzzy logic PSS[6]. These PSSs were optimally tuned to stabilize the study system. During the testing, real power flows were monitored at the nine locations in the study system as shown in Fig. 2.

Table I. Setting of Power System Stabilizers

| Case | Unit 1 | Unit 2 | Unit 3 | Unit 4 |
|------|--------|--------|--------|--------|
| 1    | CPSS   | CPSS   | CPSS   | CPSS   |
| 2    | CPSS*  | -      | -      | CPSS*  |
| 3    | CPSS*  | -      | -      | -      |
| 4    | FLPSS  | CPSS   | CPSS   | CPSS   |
| 5    | FLPSS  | -      | -      | CPSS*  |
| 6    | FLPSS  | -      | -      | -      |

In order to investigate the propagation of the background oscillations, following indices are defined.

$$BP_i = \frac{\sum_{k=1}^N |\Delta P_i(k)|}{N} \quad (1)$$

$$NBP_i = BP_i / BP_1 \quad (2)$$

where  $\Delta P_i(k)$  indicates the deviation of real power flow from its steady state value at the monitoring location  $i$  in the study system and  $N$  gives the total sampled data number. In the above two equations, the term  $BP_i$  gives the averaged size of the propagated background oscillations into the study system, and the term  $NBP_i$  gives its normalized value with respect to the averaged size  $BP_1$  of the injected background oscillations.

Fig. 6 shows the typical monitoring results of the propagation of the background oscillations into the study system under a normal condition, where only Unit 1 is quipped with a conventional PSS(CPSS\*) or a Fuzzy Logic PSS(FLPSS), and the real power output setting from Unit 1 is set to 0.3 pu. In Fig. 6, the real power flows at the nine monitoring locations are illustrated from the top to the bottom. As shown in Fig. 6, the stability of the study system is further improved by the implementation of the FLPSS on Unit 1 compared with the implementation of the CPSS.

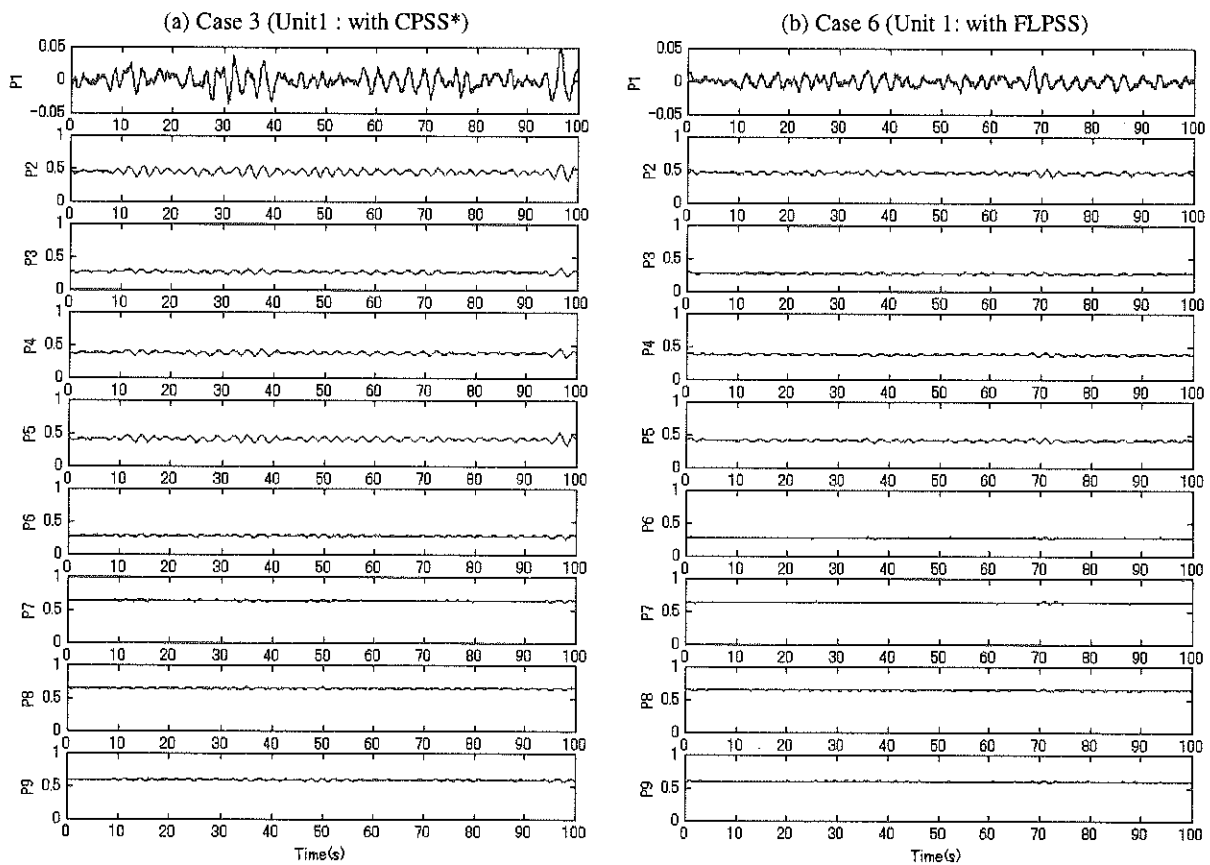


Fig. 6. Typical Monitoring Results of Propagated Background Oscillations into Study System (Only Unit 1 is equipped with CPSS\* or FLPSS. The real power setting of Unit 1 is 0.3 pu.)

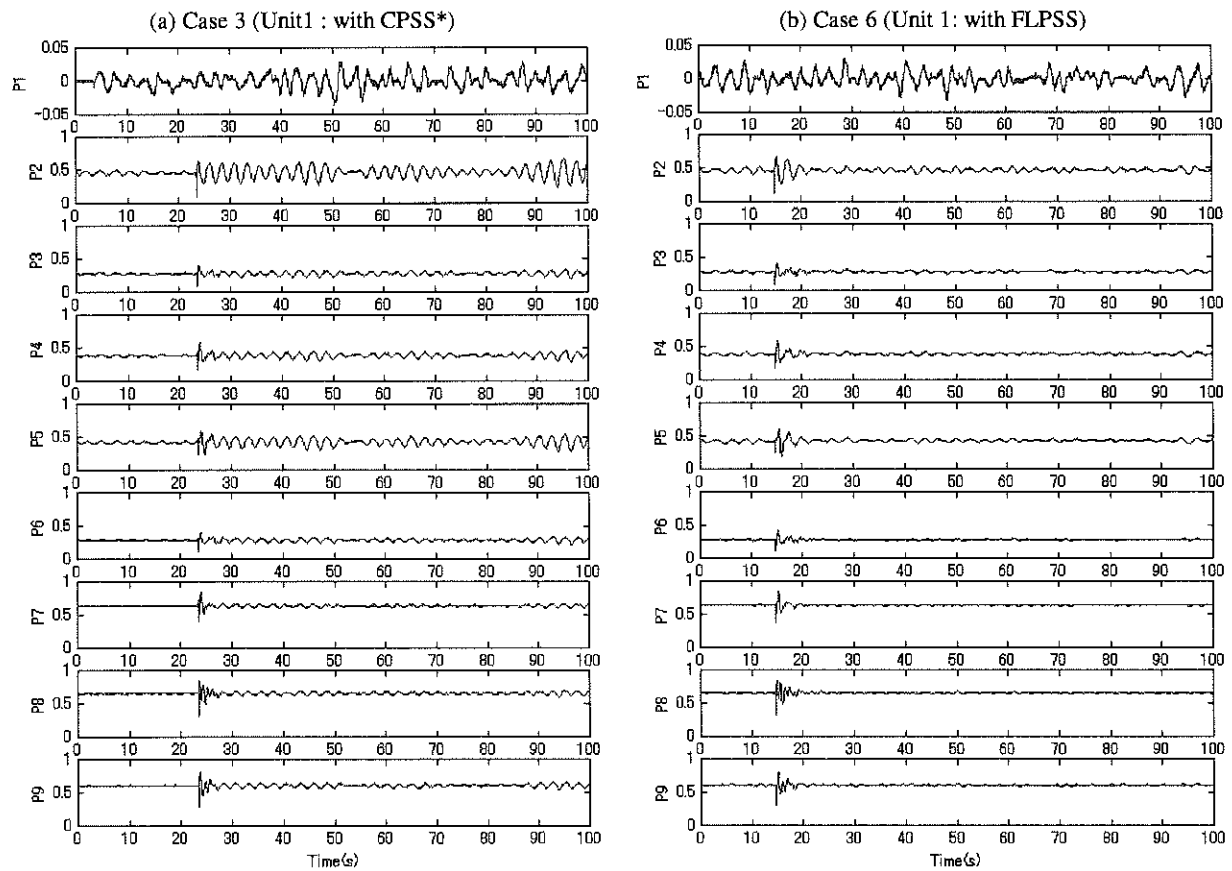


Fig. 7. Typical Monitoring Results of Propagated Background Oscillations into Study System under Faulted Condition (Only Unit 1 is equipped with CPSS\* or FLPSS. The real power setting of Unit 1 is 0.3 pu.)

Table II. Evaluation of Propagated Oscillations under Normal Condition (Real Power Setting of Unit 1 = 0.3 pu.)

| Location | Case 1 | Case 2 | Case 3 | Case 4 | Case 5 | Case 6 |
|----------|--------|--------|--------|--------|--------|--------|
| 1        | 1.00   | 1.00   | 1.00   | 1.00   | 1.00   | 1.00   |
| 2        | 2.42   | 2.24   | 3.57   | 1.88   | 2.00   | 2.74   |
| 3        | 1.24   | 1.18   | 1.47   | 1.12   | 1.14   | 1.27   |
| 4        | 1.41   | 1.35   | 1.78   | 1.21   | 1.27   | 1.47   |
| 5        | 1.79   | 1.72   | 2.47   | 1.43   | 1.53   | 1.91   |
| 6        | 0.88   | 0.58   | 0.84   | 0.55   | 0.46   | 0.62   |
| 7        | 0.55   | 0.48   | 0.57   | 0.50   | 0.45   | 0.61   |
| 8        | 0.55   | 0.51   | 0.61   | 0.46   | 0.42   | 0.56   |
| 9        | 0.75   | 0.52   | 0.86   | 0.58   | 0.43   | 0.76   |

Table III. Evaluation of Propagated Oscillations under Faulted Condition (Three-Phase to Ground Fault at Point A in Study System)

| Location | Case 1 | Case 2 | Case 3 | Case 4 | Case 5 | Case 6 |
|----------|--------|--------|--------|--------|--------|--------|
| 1        | 1.00   | 1.00   | 1.00   | 1.00   | 1.00   | 1.00   |
| 2        | 3.93   | 3.03   | 7.75   | 2.58   | 2.33   | 3.48   |
| 3        | 1.85   | 1.43   | 2.45   | 1.58   | 1.33   | 1.52   |
| 4        | 2.24   | 1.73   | 3.32   | 1.82   | 1.52   | 1.85   |
| 5        | 2.92   | 2.32   | 5.06   | 2.18   | 1.81   | 2.42   |
| 6        | 3.15   | 1.67   | 4.20   | 0.99   | 0.83   | 0.89   |
| 7        | 1.05   | 0.72   | 1.50   | 0.84   | 0.75   | 0.93   |
| 8        | 1.11   | 0.80   | 1.69   | 0.96   | 0.79   | 0.97   |
| 9        | 1.42   | 1.00   | 2.13   | 1.11   | 0.92   | 1.10   |

The propagation of the background oscillations to the External System II, i.e. the infinite bus, is reduced by the implementation of the FLPSS on Unit 1. The real power oscillation of Unit 1 is also reduced by the implementation of the FLPSS on Unit 1 as clearly shown in the graph of the real power output  $P_6$  from Unit 1.

Fig. 7 illustrates another typical results, where a three-phase to ground fault for four cycles is applied to the study system as a disturbance and the faulted line is isolated after four cycles. In the case, only Unit 1 is equipped with the CPSS\* or the FLPSS. As similar to the former results, the system stability is highly improved by the implementation of the FLPSS on Unit 1. The size of the propagated oscillations to the External System II, i.e., the infinite bus, is also reduced by the FLPSS. In addition, the oscillation of Unit 1 is well damped by the FLPSS.

In order to clarify the relationship between the propagated oscillations and the stability of the study system, the normalized index  $NBP_i$  defined by eqn.(2), is evaluated and the results are shown in Table II and in Table III under different situations.

As shown in these tables, the injected background oscillations to the study system are magnified and propagated through the study system to the External System II, i.e., the infinite bus, because of the existence of the oscillations caused in the study system from the injected background oscillations. The magnification of the injected background oscillations is also illustrated in Fig. 8. The level of the magnification depends on the strength of the study system, therefore, the FLPSS acts effectively to reduce the magnification of the injected background oscillations.

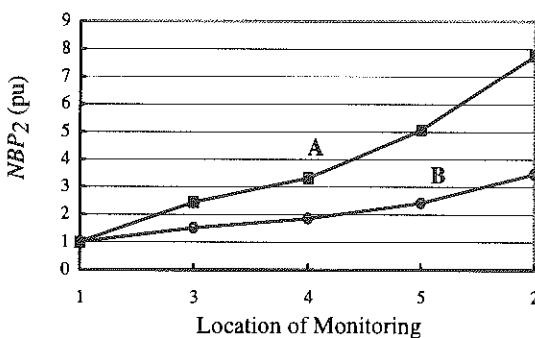


Fig. 8. Magnification of Injected Background Oscillations under Faulted Condition  
(A: with CPSS\* on Unit 1 B: with FLPSS on Unit 1)

Fig. 9 shows the values of  $NBP_2$ , which indicates the normalized size of propagated oscillations to the External System II. Only Unit 1 has the CPSS\* in the case A, and also only Unit 1 has the FLPSS in the case B. As shown in the figure, the stabilization effect achieved by the implementation of the FLPSS on Unit 1 is much higher than that of the CPSS\*.

In addition, the stability level is decreased according to the increase of the real power output of Unit 1.

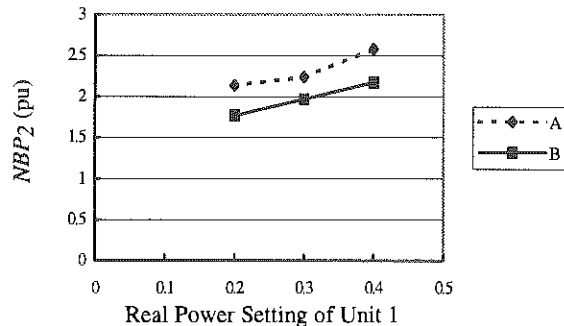


Fig. 9. Magnification of Injected Background Oscillations under Different Conditions  
(A: with CPSS\* on Unit 1 B: with FLPSS on Unit 1)

#### IV. Conclusion

The analog simulator tests have been successfully finished to investigate the propagation of the injected background oscillations from the External System I through the study four-machine system to the External System II. The size of propagated oscillations depends on the monitoring location in the study system, and also depends on the stability level of the study system. Generally, the injected background oscillations are magnified through the study system with a longitudinal configuration because of the existence of oscillations caused by the injected oscillations. Further studies are required for the detailed investigation for the modulation of background oscillations in amplitudes and also in frequencies through the study system. From the further studies, valuable insights of the stability evaluation for large-scale power systems will be obtained.

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## Discussions on Session VII: CONTROL Part 2

**Chairman (C.-C. Liu):** So we have three papers. The first one is about the mode analysis for European power systems. The second one is about battery and how they improve the stability. The last one is analog simulation. Comments and questions can also come from the presenters, if you like to discuss particular issues.

**C. Rehtanz:** I have a question for Professor Erlich. The simulation, which has been done before the UCTE system is switched together before the Eastern countries, like Poland and Hungary are switched to the West part. All the simulation which has done before, and all the system study has shown there will be no problem, the system will be stable. After that, after the system was switched together, in Germany they found oscillations between Poland and Spain and some other things, which was badly damaged. Therefore, I want to ask you how sensitive is such a model? Does it really find the appropriate oscillation modes, because also other systems like the WSCC system in 1996, there was an oscillation mode, which has not been seen before. You can tune your model that shows perfectly what happened. But how is the correlation and sensitivity, because some parameters are not well known, you make an assumption, you get some oscillation, you make other assumption, you will not get it. Could you give us your comment?

**I. Erlich:** The simulation I show here is out of a system with an extension in the south area of Romania and Bulgaria and so on. But we have carried out calculations in other systems, but not without the central part. All investigations we have carried out is with central. The record I show here was with central. This was a problem because this wide-area measurement system is first designed, it got a set time, central was connected to the western part. Therefore, people said this is the reason, the connection is a reason why we have oscillations. In my opinion, this is not the case. We have had this oscillation before. But it was recorded. You said the oscillations are very sensitive. Of course, we can change the voltage level you have damped system and undamped system, and so on. Power transit is only one variable in this relation. Other variables of voltage level or voltage control gains are most important. The problem is I don't have a good model for the western part. People in the western area have no model from the eastern area. We don't know exactly the load flow or other quantities in this area. It is difficult to investigate such a model.

**K. Iba (Mitsubishi):** I have one question to Mr. Ohtaka. In the paper you said, a NAS battery is very effective

to control reactive power. Do you have any experience comparing NAS battery and SVG static var generator.

**T. Ohtaka:** I think that other battery systems can do the same function, but the NAS battery systems do not need some facilities, such as cooling systems, pumps and valves, and NAS battery has high energy density. So NAS battery can be installed in a small space more than other battery systems. SVG can regulate the reactive power, but NAS battery can output the active and reactive power flexibly and independently. So in distributing systems, it is also effective to improve the voltage stability or separate the voltage fluctuation to be able to mix the active and reactive powers is the other advantage of the system.

**V. Ajjarapu (Iiowa State University):** Would you please tell me what is the capacity of the battery? And how often you have to charge that battery?

**T. Ohtaka:** The NAS battery can be charged about 2000 times over the period of 15 to 20 years.

**Chairman:** I thought the slide says 6000 kilowatts, 6 megawatts. Is that the capacity of the battery? Then the question is how often you have to charge the battery.

**T. Ohtaka:** The NAS battery charges and discharges everyday. This is the usual use. The NAS battery can charge or discharge. In this case, we use 6000 kilowatt NAS battery, so we can charge or discharge from twice to 5 times as large as a rated 6000 kilowatt.

**S. Iwamoto:** About your question, I think there is a misunderstanding. The battery is charged when it is installed. This battery is used like a pump-up storage plant, so this is a kind of small pump-up storage plant. The life is like 15 years. You can charge using the electricity once and recharge, also once a day. So in a day you charge and recharge, but you don't have to any other things. The lifetime is 15 years, that is the design. Right now the maximum capacity is 6 MW as you see on the screen.

**T. Ohtaka:** As to the installation cost, as far as I know, the installation cost is about \$5000 per kilowatt. The goal of this installation cost is \$2000 per watt kilowatt.

**C. C. Liu:** \$5000 per kilowatt times 6000 kilowatt. That's quite a bit.

**C. Canizares:** Professor Ohtaka, I have a question: comparing NAS and another system that would do

something similar, do you have any idea in terms of the cost and, size?

**T. Ohtaka:** I think SMES also can do the same function, because the proposal of this method is the function of the inverter system. I think the SMES device can do the same function.

**C. Canizares:** In terms of space, cost?

**T. Ohtaka:** I think SMES, NAS battery system can be installed more compactly in device. How compact? I don't know. As for the cost, I think the NAS battery is cheaper. As I mentioned before, the NAS battery system does not need standard facilities, such as cooling system, so NAS battery system is cheaper than the SMES device.

**K. Iba:** Do you have any experience to observe low oscillation power swings in your power system, because I want to know your motivation of your research especially dedicated to the background of oscillations? Do you observe low frequency power oscillations in your power system? Is it very severe?

**T. Funakoshi:** In the west Japan, the system has low frequency oscillations. Now stability is lower because the night time stability is very low. The electric company has a stability system for stability margin.

**Chairman:** Why do you use an analog power system simulator?

**T. Funakoshi:** We have both simulators. We use the simulator for research.

**H. Sasaki (Hiroshima University):** I would like to ask all the persons who raised questions and comments to submit in writing. There is misunderstanding and difficulty in what the questioner has said. So in a written form, maybe all the authors can respond quickly and also the value of the proceedings will be enhanced.

**Chairman:** Thank you. If there is no more question, we will close the session.



**Session VIII:**  
**SYSTEM ANALYSIS**

Thursday, August 30, 16:30–20:00

Chair: David J. Hill

# On Modal Resonance and Interarea Oscillations in Power Systems

Lawrence Jones

Göran Andersson

Valery Knyazkin

**Abstract**— This paper investigates the phenomenon of modal resonance in power systems. Results are presented which reveal interacting pairs of eigenvalues in a 19 machine model of the Western North American power grid. The dynamics in the actual WSCC system around 0.7 Hz has been an enigma for many years. Abnormal behavior has been linked to the possibility of a kind of resonance between modes. The findings presented in this paper strongly supports that conjecture.

A heuristic procedure for identifying resonance is proposed. Geometric interpretations of the qualitative results are given. Graphical illustrations provide lucid visualization of the phenomenon and how it is affected by different system parameters.

**Keywords**— Eigenvalue Interaction, Modal Resonance, Diagonalizable, Power Systems, Interarea Oscillations, Strong Resonance, Weak Resonance

## I. INTRODUCTION

THE deregulation of electric power industry in many parts of the world has led to the creation of large entities for transmission, generation, and distribution of electric energy, e.g. Regional Transmission Organization (RTO) in North America. Due to inadequate local power generation, more bulk power transfer between interconnected systems can be expected [1]. These and other related factors will increase the amount and types data used for system planning and design of special controls to enhance system security and reliability. Inaccurate data will mean that the studied model will not mimic the actual dynamics of the true system. As a matter of fact, other anomalous behavior, e.g. eigenvalues interactions or modal resonance, that may induce inter-area oscillations could occur in power systems. However, these may not be detectable if they are not well understood. System planning studies, controller design paradigms, and dynamic security assessment must include tools to investigate these phenomena [2], [3].

The dynamics of the WSCC system near 0.7 Hz has been an enigma for many years [2]. Abnormal behavior and strange results have always been linked to the possibility of a kind of resonance between modes. The motivation for this work was the intent to verify that findings that provided evidence of interacting modes in small power systems models could be applied to larger and more detailed ones [4]. Furthermore, as the phenomenon has not received much research attention, a goal of the study was to explore various aspects related to these phenomena.

Other types of interaction mechanisms are more related to the fundamental dynamic properties of the systems. One which has been studied widely in many areas of engineering is resonance. There are different kinds of resonance that

can occur in dynamical systems. The one most well-known occurs when a natural frequency of the system coincides with the frequency of the forcing function. Resonant interactions can also occur due to changes in the structure of a system, e.g. loss of symmetry, and in critical parameters. Depending on the studied system, near-collision of of natural modes can lead to drastic changes in system dynamics. Problems involving resonant interactions in large systems are often of higher dimension and complex, making existing methods not feasible to study them analytically. In this paper, the computational approach will be used to study modal resonance in the studied power system.

The performance of a controller is known to depend strongly on the relative location of the eigenvalues (poles) to the zeros of the open loop transfer function. As zeros are the counterparts of poles, the mechanism of near resonance can also occur for the zeros [3]. Interacting system zeros as a precursor of nonminimum phase systems are currently being investigated.

The remainder of this paper is as follows. Section II provides a background on modal resonance and eigenvalue movements near resonance. In Section III, a procedure to identify eigenvalue interaction is presented. In Section IV, a case study of the 0.7 Hz cluster of interarea modes in a reduced-order model of WSCC system is conducted. The procedure to investigate eigenvalue interaction is applied to the test power system. The identified near resonant condition is analyzed more closely. First the mode shapes are discussed. Geometric interpretations of the observed eigenvalue interaction are presented. The effects of small parameter changes on the eigenvalues and their behavior near resonance are illustrated. Finally, in Section V, the impact of symmetry is demonstrated for a simplified test system.

## II. MODAL RESONANCE

### A. Background

Power system oscillatory dynamics is based on the linearization of a nonlinear differential-algebraic model about an equilibrium point which is determined by the operating condition. Changes in system parameters vary the linearization and the characteristic modal properties, e.g. eigenvalue, mode shapes.

Modal resonance is the phenomenon in which two eigenvalues of a linear system coalesce due to parameter changes. As a result, the system may either be at diagonalizable resonance (DR) or a nondiagonalizable resonance (NDR). In [9], eigenvalue interactions are analyzed based on perturbation theory. There, interactions are termed *weak* in the

case of diagonalizable resonance, while *strong* interactions correspond to the nondiagonalizable case. In either case, the eigenvalues interact in some sense. The phenomenon can therefore be an onset of system instability in that the eigenvalues can undergo a change in magnitude and direction of movement. One of the pairs will follow a destabilizing direction. Interaction occurring near the imaginary axis may lead to Hopf or saddle node bifurcation [5] when eigenvalues cross the imaginary axis.

Of the two kinds of resonance, NDR is the one that could theoretically occur in linearized power system models. However, the number of independent parameters that must be varied for exact NDR makes it a rare event. Practical power systems can come close to a NDR hence experiencing a *near nondiagonalizable resonance* (NNDR).

In the literature, the occurrence of modal resonance in linear oscillatory systems has been studied for parameterized matrices in general [6], [7]. The first known detailed account of the possibility that NNDR can occur in practical system is found in [4]. That work also provides a good explanation of the theory and review of previous power systems work related to this subject. Two test power systems, 3 and 9 buses, were used to illustrate that the phenomenon can occur. Eigenvalue movements characteristic of modal resonance are shown in [8] in connection with tuning PSS for a multi-generator plant. In this case, as the PSS gain is increased to improve the damping of a given mode, two other eigenvalues interact as the system passes a NNDR.

The characteristic behavior of NNDR at some region in the parameter space can be summarized as follows: [4], [9]

- Eigenvalues and their corresponding eigenvectors are very sensitive to parameter variations.
- General parameter variation can cause the direction of the eigenvalues to turn quickly through approximately right angles.
- The right and left eigenvectors are almost orthogonal.
- The right eigenvector of the two modes are nearly aligned, i.e the two modes have similar oscillating patterns.

#### B. Eigenvector Sensitivity

Another way to gain insight about eigenvalue interaction is to consider the eigenvector sensitivity. As has been discussed, when two eigenvalues approach each other, they become more sensitive to parameter changes and beyond a critical parameter value they deflect at an angle of about 90 degrees. For NNDR, the eigenvalue and eigenvector are very sensitive to changes in system parameters. Eigenvector sensitivity near resonance can also be explained by examining the corresponding analytical expression given in Eq. (1), [11] pp. 345-46, [10].

$$\frac{\partial v_i}{\partial p} = \sum_{j=1, j \neq i}^n \beta_{ij} v_j \quad (1)$$

where

$$\beta_{ij} = \frac{w_j^T \left\{ \frac{\partial A}{\partial p} + \lambda_i \frac{\partial E}{\partial p} \right\} v_i}{(\lambda_i - \lambda_j) w_i^T E v_j} \quad (2)$$

The denominator of Eq. (1) contains the term  $(\lambda_i - \lambda_j)$  indicating high sensitivity when the eigenvalues approach

each other. Recall that eigenvalue sensitivity given by Eq. (3) for the generalized eigenvalue problem is a function of the eigenvector.

$$\frac{\partial \lambda_i}{\partial p} = \frac{w_i^T \frac{\partial A}{\partial p} v_i - \lambda_i w_i^T \frac{\partial E}{\partial p} v_i}{w_i^T E v_i} \quad (3)$$

Up to the first order terms of a Taylor expansion, the eigenvalue and eigenvector are given by

$$\lambda = \lambda_0 + \frac{\partial \lambda}{\partial p} \Delta p \quad (4)$$

and

$$v = v_0 + \frac{\partial v}{\partial p} \Delta p \quad (5)$$

Hence, both the eigenvalue and eigenvectors are very sensitive near resonance.

### III. HEURISTIC PROCEDURE TO IDENTIFY MODAL RESONANCE

Detection of modal resonance in a power system model can be a long process, especially if the studied system dynamics is not known. Based on numerous simulation results from studying different systems [13], the following two conditions seem to increase the likelihood that given pairs of eigenvalue interact. These are:

- Modes must be within a certain frequency band for them to interact.
- The sensitivity of the pairs of eigenvalues with respect to the studied parameter must be opposite. In a mode cluster two modes are likely to interact if the phase angles of their first order sensitivity are 180 degrees apart for a region in the parameter space.

#### Procedure

1. Define a critical operating region within which an interaction could occur.
2. Calculate the eigenvalues that are assumed to be within a critical frequency range.
3. Vary a critical system parameter, e.g. generator inertia constant, or active power of system load.
4. Check which eigenvalues move and if there are two eigenvalues moving towards each other or away from each other.
5. If there are no pairs of eigenvalues that move simultaneously, critical parameter should be chosen. If there is still no behavior which could be indicative of interaction, modify the system slightly. For instance, increase the length of a line or change the set voltage of a generator, so that two moving - values come closer together. This step may be automated based on sensitivity analysis techniques.
6. When an interacting pair of eigenvalues is detected, determine in which directions the eigenvalues turn. One way to do this is to perturb the NNDR by changing a suitable parameter.

When carrying out system studies to detect modal resonance, the list of characteristics behavior for the case of NNDR given in the previous section, may be used as good indicators of being near a resonance point.

#### IV. CASE STUDY

In this section, a study of the system's 0.7 Hz mode cluster is conducted. The main aims are to check if, in fact, there are interacting eigenvalues, to verify the explanations on modal resonance which have been discussed in previous sections, to validate the genericity of results reported in [4], and to provide more insight about this phenomenon.

The single line diagram of the studied system is shown in Figure 1. This system has a structure and dynamics similar to the power grid in Western North America. The model consists of 19 machines distributed in 7 areas. Each area has two or three machines. One machine is represented by the classical model and the others are represented by a detailed two-axis model with static excitation system. Classical machines represent aggregation of several machines into a very large machine. There are no governors and the damping constant for machines is 2.0 pu. More details about this model are given in [12]. The complete system data may be obtained from [14]. The nominal case for the study is chosen such that the system is stable. In the search for modal resonance, the active power load in Arizona is varied from 7300–10500 MW. The eigenvalue loci for the starting point are depicted in Figure 2. Note that no kind of interaction seems to occur.

##### A. Inter-area mode interaction

The eigenvalue and mode shapes of the linearized power system model vary with operating conditions and the accuracy of the analysis will strongly depend on system data. For example, during system planning inaccurate data will mean that the studied data will not mimic the actual dynamics of the system. The uncertainty in the data could be the result of model reduction or simply incorrect parameter data. In addition, anomalous behavior may not be detected even while performing detailed stability studies.

An important quantity for resonance is the frequency of modes. It is a function of the inertia of the synchronous machines. One typical procedure in model reduction is the aggregation of groups of machines which have similar dynamic properties for dominant modes. This procedure could be a source of model uncertainty making it difficult to observe phenomena such as eigenvalue interactions. In the sequel, we assume that the inertia constant of generator 2 has a parametric uncertainty defined by  $\Delta H_2 = 0.7$  MW/MVAs. The inertia constant is therefore set to 3.508. All other system conditions remain the same.

The load at Arizona is varied as before and the eigenvalue loci are shown in Figure 3. Some kind of interaction seems to occur between modes around 0.7 Hz. A zoom of that part of the curve is depicted in Figure 4 and it is clear that the eigenvalues interact near resonance.

Thus, this establishes that modal resonance occurs in this model of the WSCC AC system. Clearly, for a more detailed model, it is very likely that eigenvalues may pass a NNDR in other critical operating points. That this has not been observed earlier, does not mean that it has not occurred. Stability studies are often concentrated on the poorly damped or undamped modes and not the relative

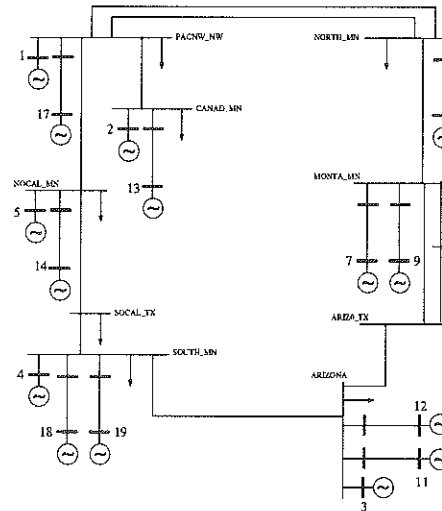


Fig. 1. 19-machine model of the WSCC system

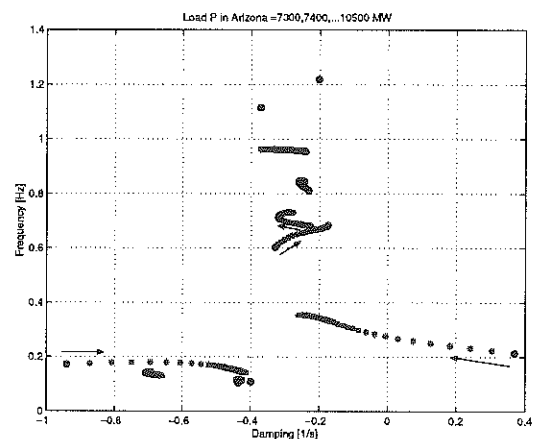


Fig. 2. Eigenvalues movements for load increase at Arizona

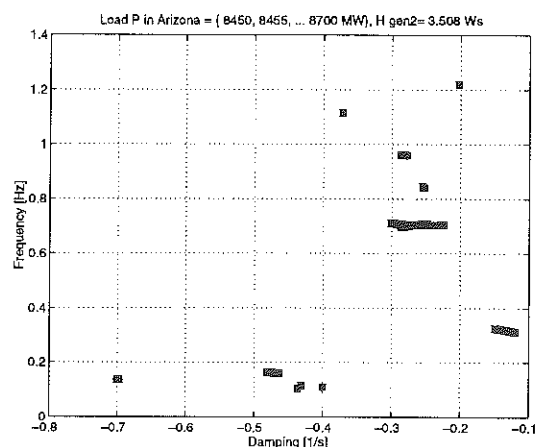


Fig. 3. Interacting eigenvalues between 0.6 – 0.7 Hz

movement between modes at close frequency, especially so when they are initially well damped. This could be one reason why this phenomenon may not be often observed. This possibility that two pairs of eigenvalues can interact at NNDR and lead to destabilization and interarea oscillations should be studied carefully, and especially in the case of mode clusters near the imaginary axis.

### B. Resonance and Mode Shapes

Modal resonance implies eigenvalue multiplicity 2. In the previous subsection, the classification of resonance was based on whether the system matrix can be diagonalized or not. In linear systems theory, *diagonalization* is concerned with the eigenvectors, i.e., the mode shapes. Resonance for which the system has a full set of distinct eigenvectors is considered diagonalizable. Otherwise, it is nondiagonalizable in which case two eigenvectors coincide. Thus, when the system comes to a NNDR point, the right eigenvectors of the interacting eigenvalues become more aligned.

In the studied example, the interacting modes were associated with electromechanical state variables. Inspection of the mode shapes showed that the magnitude of elements corresponding to other variables were close to zero and did not change significantly for load changes around NNDR point compared to components for speed deviations. Hence, to check how the modes shape change only the latter components were considered. Figures 5 and 6 show that, before resonance, the magnitude and phase angle of speed deviation components of mode shape corresponding to the two interacting eigenvalues are different. As shown in Figures 7 and 8, the traces become almost completely aligned at the onset of eigenvalues interaction, at NNDR. Above the parameter value for near resonance, the mode shape are not aligned as shown by separation of the traces in Figures 9 and 10. Exact alignment of mode shapes should not be expected in actual power systems models.

### C. Geometric Interpretation of Modal Resonance

The phenomenon of modal resonance involving collision or interaction of eigenvalues is studied in [9] for linear oscillatory systems which can be described by

$$M\ddot{x} + D\dot{x} + Kx = 0 \quad (6)$$

where  $M$ ,  $D$ , and  $K$  are square matrices of order  $n$ , representing inertia, damping, and rigidity properties of the system. The matrices are assumed to be smooth functions of system parameters,  $p_1, p_2, \dots, p_n$ . Similar equations are known to represent power system linearized models. Assuming that  $M$  is nonsingular, Eq. (6) may also be reduced to the standard eigenvalue problem with state matrix  $A$ . We assume that  $A$  is real and non-symmetric.

In the previous section, the occurrence of modal resonance was classified as being diagonalizable (DR) or nondiagonalizable (NDR). In [9], eigenvalue interactions are analyzed based on perturbation theory. There, interactions are termed *weak* in the case of diagonalizable resonance, while *strong* interactions correspond to the nondiagonalizable case. Noteworthy is the fact that strong interaction

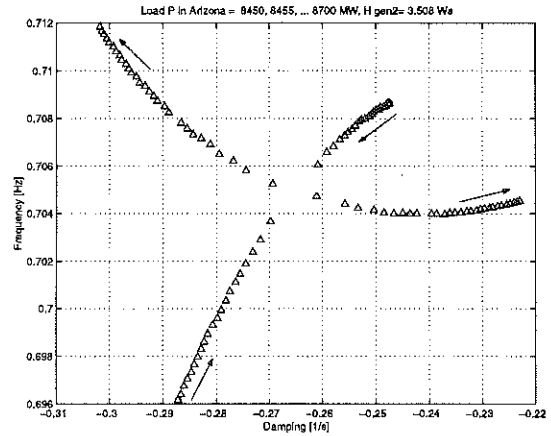


Fig. 4. Zoom of Figure 3 between 0.68 – 0.72 Hz

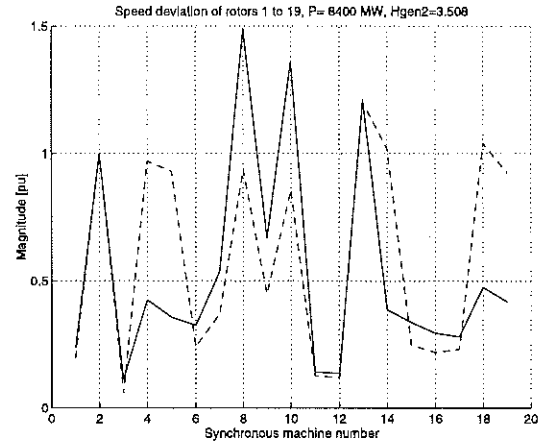


Fig. 5. Magnitude of machine speed component in the eigenvector before NNDR (Solid trace =  $\lambda_1$ , Dash trace =  $\lambda_2$ )

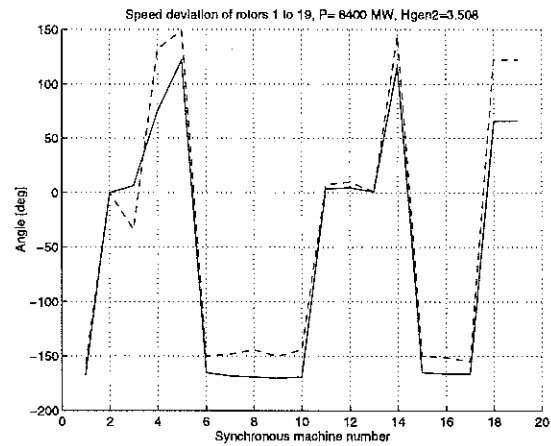


Fig. 6. Phase angle of machine speed component in the eigenvector before NNDR (Solid trace =  $\lambda_1$ , Dash trace =  $\lambda_2$ )

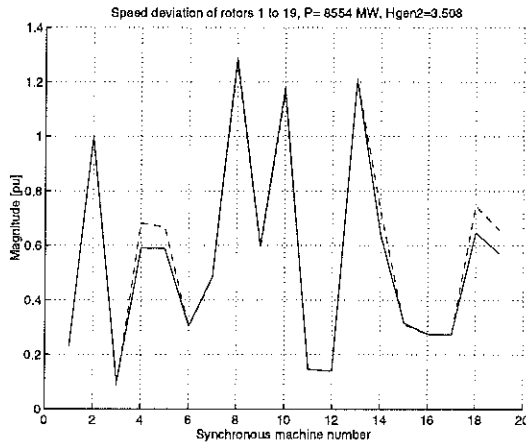


Fig. 7. Magnitude of machine speed component in eigenvector at NNDR (Solid trace =  $\lambda_1$ , Dash trace =  $\lambda_2$ )

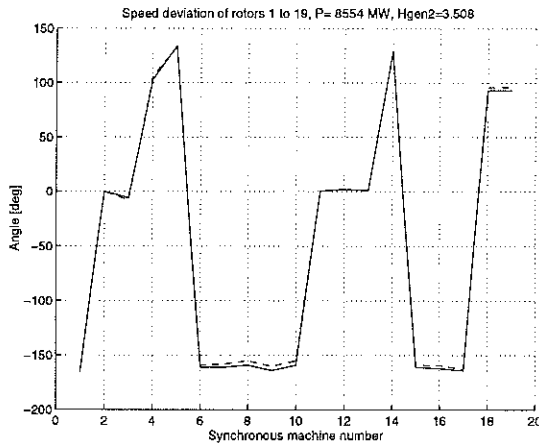


Fig. 8. Phase angle of machine speed component in eigenvector at NNDR (Solid trace =  $\lambda_1$ , Dash trace =  $\lambda_2$ )

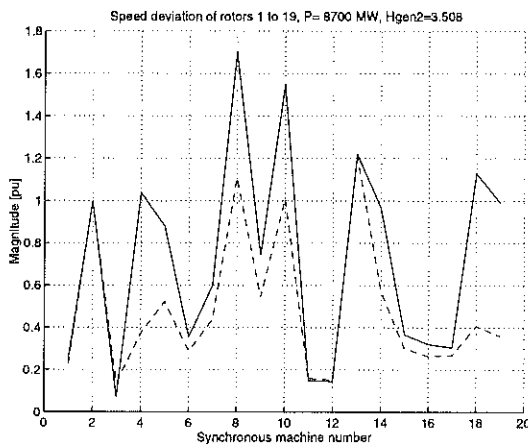


Fig. 9. Magnitude of machine speed component in the eigenvector after NNDR (Solid trace =  $\lambda_1$ , Dash trace =  $\lambda_2$ )

is characterized by the coincidence of both eigenvalues and eigenvectors, while, weak interaction is characterized by coincidence of eigenvalues only. It is also pointed out that the former can always be achieved for symmetric matrices. However, in general, realistic models of dynamical systems always contain enough dis-symmetry that these conditions are never satisfied *exactly*. In practical power systems, NNDR is more likely to occur as have been demonstrated for the 19 machine test system.

Figure 11 is a three dimensional representation of Figure 4. A similar qualitative description of the case of exact strong interaction is found in [9]. It has been discussed that exact NDR is not expected to occur in practical power system models but rather eigenvalues can be expected to pass near such a resonance. Figures 12 and 13 give another view of Figure 4 and 15, respectively. Note that in the former case which corresponds to being extremely close to the resonance point, the eigenvalues move approximately in the same plane, i.e., the upper curve in Figure 11. For a small perturbation in system voltage the eigenvalues move on two parallel planes. We conjecture that this distance is expected to get wider for large perturbations. This behavior is somewhat analogous to the creation of a bubble when a weak interaction is changed by two strong interactions [9]. To check this, the system voltage was subjected to a bigger perturbation. The result is shown in 14. Note the increase in the distance between the two parallel planes for large changes.

#### D. Perturbation of Nondiagonalizable Resonance

When two eigenvalues interact and branch away at right angles, it is not often clear exactly which eigenvalue moves in what direction. One way to find out is to apply a small change to the system such that the NDR is perturbed. In [4], it is shown for the simple 3 bus system that the eigenvalue angle of deflection for NNDR changed depending on the direction of change in the generator set voltages. This behavior is also observed here as shown, in Figure 15 for decreased and increased voltage magnitude at all system buses, respectively. The following symbols denote the different trajectories:  $\Delta$ , 'x' and '+' are trajectories at, below and above the NNDR point, respectively. These are used in the remaining sections of this paper unless stated otherwise.

That the eigenvalues turn aside differently for parameter variation was also detected for changes in a parameter of a single generator. Figure 16 shows the effect in changing only the set terminal voltage at bus 4. However, the amount of voltage deviation was specified higher, 0.05 kV instead of 0.01 kV, since an individual machine has a lower influence on the system performance. In another example, the impedance of a line between buses PACNW\_MN and CANAD\_MN is decreased and increased by a very small amount. The resulting trajectories are shown in Figure 17. They are qualitatively quite similar to those obtained for change in terminal voltage at one bus.

To evaluate the genericity in the deflection observed in Figures 15 through 17, other system and control param-

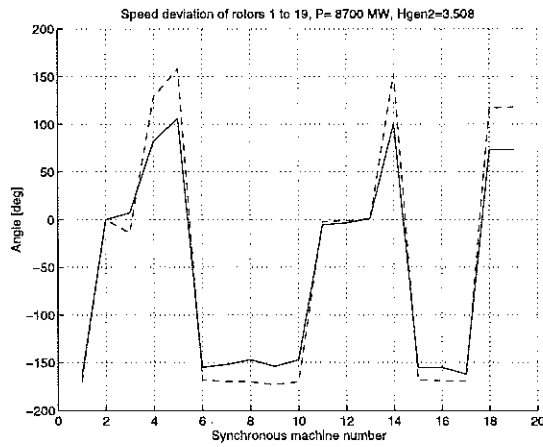


Fig. 10. Phase angle of machine speed component in eigenvector after NNDR (Solid trace =  $\lambda_1$ , Dash trace =  $\lambda_2$ )

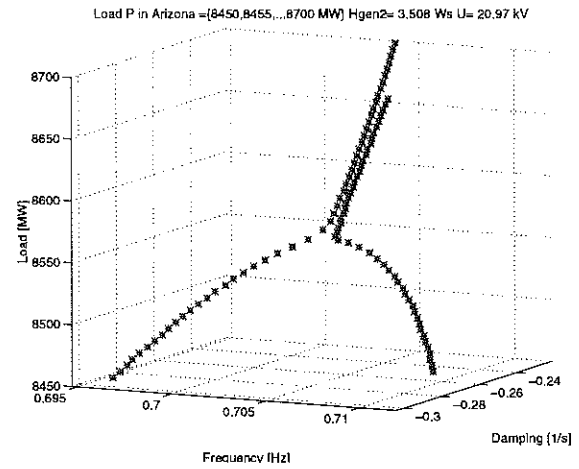


Fig. 13. Strong interaction after small perturbation: View 2

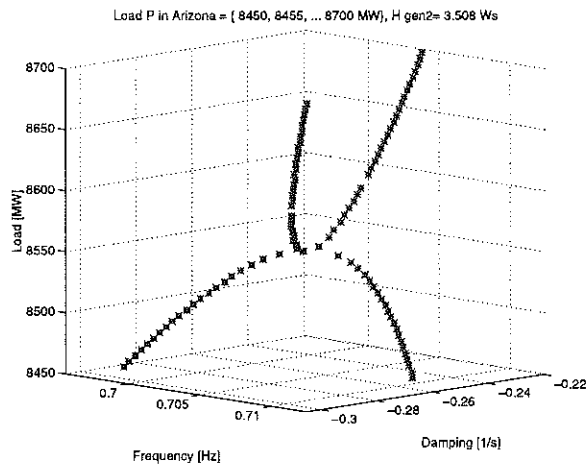


Fig. 11. Strong interaction of eigenvalues at NNDR: View 1

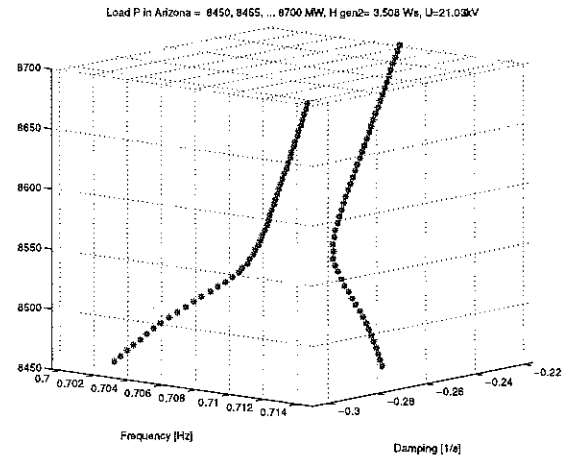


Fig. 14. Strong interaction after large perturbation: View 2

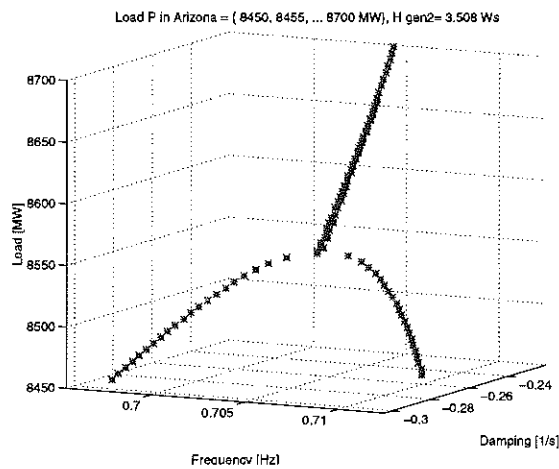


Fig. 12. Strong interaction of eigenvalues at NNDR: View 2

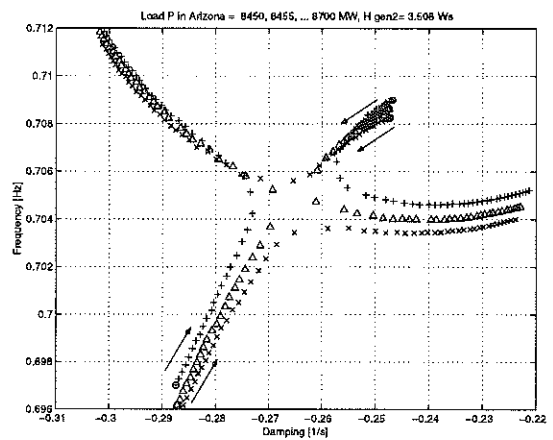


Fig. 15. Eigenvalue trajectories due to changes in terminal voltages

eters were also perturbed. For example, the exciter gain and inertia constant at generator 2 were perturbed slightly. The eigenvalue trajectories are shown in Figures 18 and 19. Similar behavior were observed for different load types as well as for alternating the machine MVA rating or inertia constant of a generator.

In the analysis of NNDR, we recommend use of the three-in-one diagram (which shows the trajectories at, above, and below the NNDR point in the parameter space) in this section. The diagram clearly shows which parameter variation has strongest influence on the NNDR. The influence is seen in terms of the distance between perturbed and original trajectories as well as the size of the bubble after the eigenvalues deflect. The influence depends on the parameter and the amount of perturbation.

### E. Symmetry and Modal Resonance

We know that in undamped linear dynamic systems, as a pair of eigenvalues move along the imaginary axis due parameter variation, while passing through a 1:1 resonance they may bypass each other or split, depending on the symmetry of the system [15], [16]. Splitting of undamped eigenvalues results in resonance bifurcation and the system stability is lost. This is the case of the well-known flutter dynamics phenomenon. Symmetry is also very important for how eigenvalues interact in systems with damping as well. In this subsection, we attempt to check the influence that symmetry has on how eigenvalues of a given power system model interact.

Theoretically, for matrices with double eigenvalues, two linearly independent eigenvectors can always be found making the linearization diagonalizable, hence a DR. In [4], the authors suggest that the bilateral symmetry of the 2 areas and 4 machines system in [17] may suppress the occurrence of NDR. Although perfect bilateral symmetry is unlikely to occur in a practical power system, we present here simulation results to see what other changes one can expect for the case of topological symmetry but not necessarily exact symmetrical operating conditions. In this case, one can not say for sure whether the state matrix is symmetric or not.

Consider the hypothetical 4 area 4 machine system shown in Figure 20. It is composed of two identical sub-systems with the same machines and transmission lines. The subsystems are interconnected through a tie line. The system has a high degree of symmetry. Initially all the generators have the same set voltage of 20 kV and each supply 84.7 MW. The system load is 320 MW. For unequal active power supplied by generators 1 and 2 (the later being the slack) the system encounters a NNDR as shown in Figure 21. Because of the symmetric structure, increase(or decrease) of power at generator 1(or generator 2) did not change the resonance point. The voltage magnitude at buses 3 and 4 were perturbed, but this however did not affect the trajectory as their power dispatch remained constant.

In another example, the terminal voltage at generators 1 and 2 are perturbed by the same amount as for generators

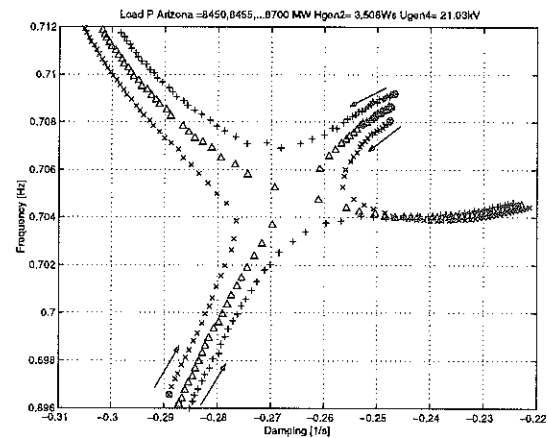


Fig. 16. Eigenvalue trajectories after an increase in set terminal voltage at bus 4

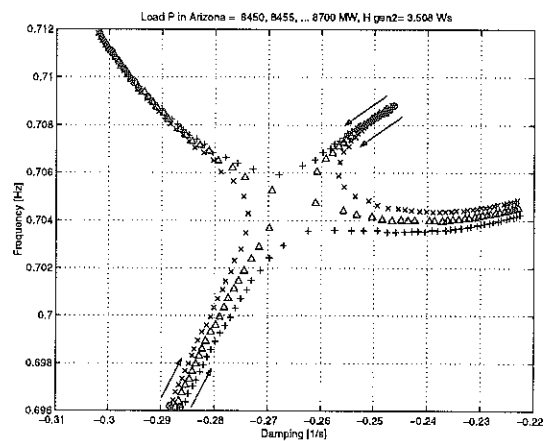


Fig. 17. Eigenvalue trajectories due to change in a line impedance

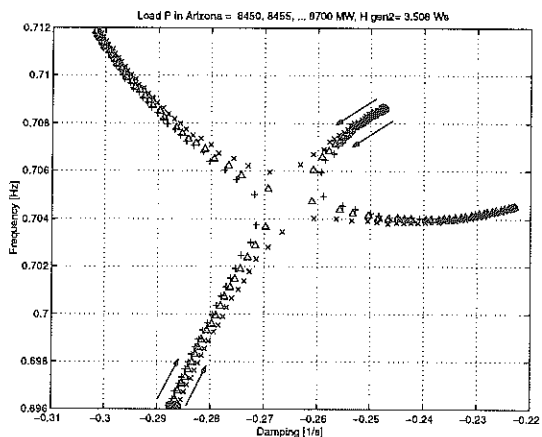


Fig. 18. Eigenvalues trajectories due to changing exciter gain



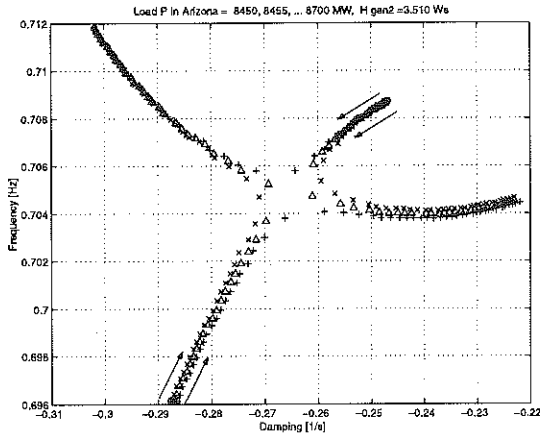


Fig. 19. Eigenvalues trajectories due to change in inertia constant at generator 2

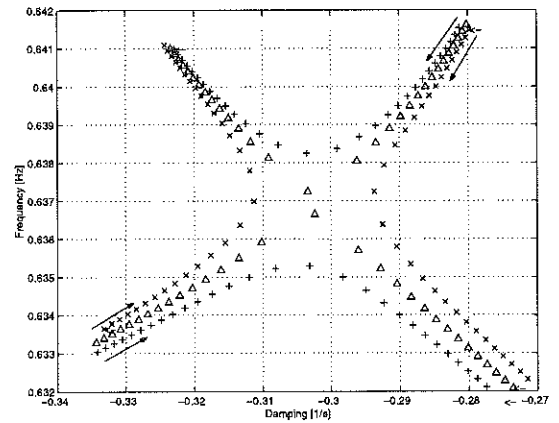


Fig. 22. Perturbed NNDR due to changes in  $U_1$  and  $U_2$

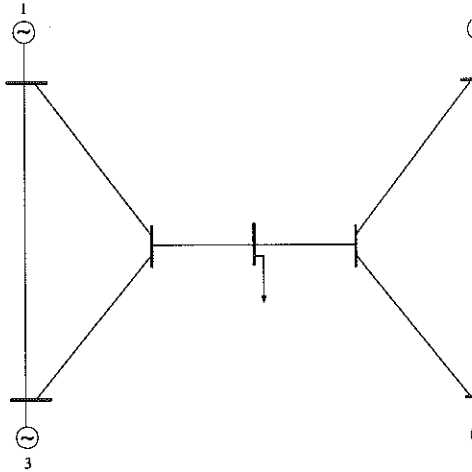


Fig. 20. Hypothetical 4 area - 4 machine system

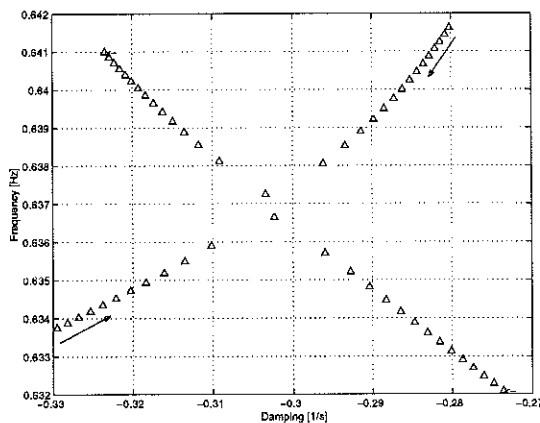


Fig. 21. Unperturbed NNDR due to changes in  $U_3$  and  $U_4$

3 and 4.  $U_1 = 19.99$  kV and  $U_2 = 20.01$  kV. Two cases of variation in the active power dispatch from generator 2 are considered:  $P_{g2} = (11.72, 11.74, \dots, 17.52)$  MW and  $P_{g2} = (152.84, 153.04, \dots, 158.74)$  MW. Figure 22 shows that NNDR is perturbed in each case.

These examples suggest that even for this power system with its symmetry, exact NDR does not occur. The result indicates that in the case of symmetry a particular set of parameters must be changed in order to perturb the NNDR compared with a non-symmetric system.

## V. CONCLUSIONS AND FUTURE WORK

### A. Conclusions

Modal resonance can occur in large power systems. The evidence of modal resonance in the 19 machine model of the Western North America power grid is important. It supports one of many conjectures suggested to explain the puzzling dynamics which have been observed in that system for many years. Furthermore, it provides new insights into the phenomenon of interacting eigenvalues. To cope with the new problems, insights on the phenomena like modal resonance will have to be incorporated into the traditional paradigms for stability studies. A heuristic procedure for identifying resonance proposed in this provides a starting point. Graphical illustrations provide lucid visualization of the phenomenon and how it is affected by different system parameters.

### B. Future Work

The work reported in this thesis on modal resonance should be followed by more research. Detection of modal resonance in a generic power system model can be a tedious process, especially if the studied system is not well known. The key issue is to determine which parameter(s) for the range of operating conditions are critical. A primary task should involve the development of tools for detect-

ing eigenvalue interaction while performing system studies. The proposed heuristic procedure is by no means fully developed. An automated procedure which incorporates information about the sensitivity of candidate interacting pairs of eigenvalues to critical parameter could speed up the search process.

It should be useful to explore how controllers for damping interarea oscillations perform when there are several poorly damped low frequency modes at a NNDR point. In general, controlling a cluster of interarea modes with low damping should be investigated further [18]. A sequel to this work should involve study of the influence of DC links, FACTS devices and other structural changes, as well as system symmetry.

It is noted that as closely spaced poles approach each other, it becomes more difficult to distinguish them. Work is ongoing to develop techniques to identify electromechanical eigenvalues in a cluster using measured or simulated time response data. The techniques can be used as part of tools for dynamic security assessments including, near real-time monitoring of system dynamic performance, validation of controller settings and of models used in off-line analysis and planning studies.

#### ACKNOWLEDGMENTS

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## Coherency Techniques for Dynamic Equivalents Incorporating Rotor and Voltage Dynamics

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**Abstract:** Dynamic equivalencing, which reduces a large power system model to a smaller equivalent system, is required to reduce the computation for dynamic security assessment. Traditional coherency and aggregation techniques do not include voltage dynamics. The accuracy of the reduced dynamic equivalent system is not reliable if the voltage characteristics of the original system are not modeled. This paper presents new coherency identification techniques for constructing dynamic equivalents that retain voltage characteristics. This paper also presents the results of a detailed study on how different limits and locations of voltage control devices such as AVR affect the coherency of generators. Numerical simulation results based on a NPCC 48-machine test system are presented to demonstrate the performance of the proposed method.

**Keywords:** Power system dynamics, coherency identification, model reduction, dynamic equivalents, eigenvalues

### I. INTRODUCTION

For reliability of power systems in the competitive environment, it is required to evaluate the impact of electric energy transactions on the operations of the system. In addition, stability studies of power systems need to consider the interconnections as the power transfer levels between systems increase. Dynamic studies need to incorporate neighboring systems as interactions between a system and its external systems can affect the system reliability. For stability studies of large interconnected power systems, it is time consuming to analyze a large number of scenarios with the entire system model including external systems. Therefore, dynamic equivalencing, which reduces a large power system model to a smaller equivalent system, is required to reduce the computational efforts.

Coherent generators with similar rotor angle waveforms following a disturbance can be represented by an equivalent generator. Coherency identification is an important task to construct the reduced dynamic equivalent system. Traditional coherency methods for model reduction [1-5] do not consider the variation in voltage magnitudes due to weak coupling between real power and voltage. Therefore, these models are not able to handle voltage-related scenarios as generator AVR control actions and load bus voltage variations. The accuracy of the reduced dynamic equivalent system is not reliable if

the voltage characteristics of the original system are not modeled.

This paper presents new coherency identification techniques for constructing reduced dynamic equivalents that retain voltage characteristics. This paper also presents the results of a detailed study on how different voltage control devices such as AVR affect the coherency of generators.

The proposed method could be extended for fast evaluation of the Available Transfer Capability for an interconnected grid. The method is also important for fast (near real-time) dynamic security assessment, where the model can be simplified. The proposed method can be used to generate models for fast dynamic simulations on a real time digital simulator (RTDS).

In this paper, the effects of AVR control action on the coherency are described in general in Section I. Next, the coherency identification problem will be formulated with the linearized system model incorporating rotor and voltage dynamics generators in Section III. In Section IV, the proposed coherency grouping method using K-means algorithm is presented according to our coherency measure. Finally, numerical testing is conducted with a NPCC 48-machine power system for verification and comparison of the proposed coherency methods in Section V.

### II. EFFECT OF VOLTAGE VARIATION ON COHERENCY

The effect of variation in voltage magnitude on the coherency can be generally described by following aspects.

- Effect of AVR controls and location
- Effect of generator terminal voltage variation
- Effect of load bus voltage variation

To investigate the effect of generator AVR location on coherency, consider a simple power system with generator excitation controls in Figure 1. Generators 1, 2 and 3 have the identical machine inertia, transient reactance and terminal voltage magnitude. They are all connected to bus 4 with the same line impedance.

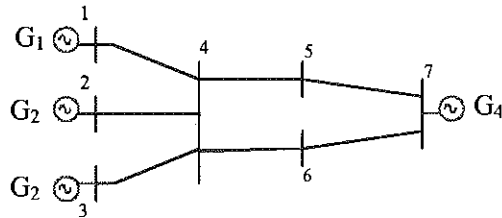


Figure 1. 4-machine 7-bus system

Two test cases are considered to investigate the effect of AVR location on coherency. It is assumed in case 1 that generators 1, 2 and 3 do not have any automatic voltage regulator. On the other hand, it is assumed in case 2 that automatic voltage regulators are available at generators 1 and 2. The rotor angle responses of generators were simulated in the time domain for a 3-phase fault at bus 5 with Matlab Power System Toolbox [6]. Figures 2 and 3 show the rotor angle responses of generators of case 1 and case 2, respectively.

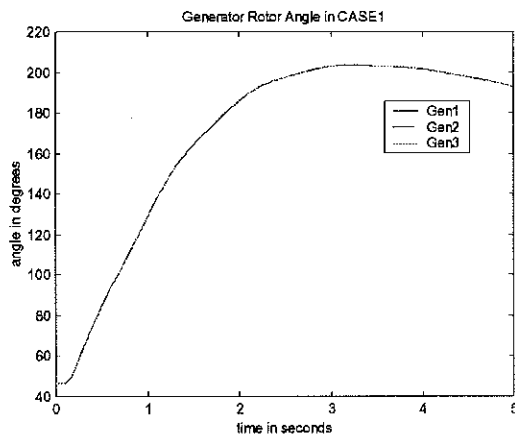


Figure 2. Rotor angle curves for generator 1, 2 and 3 of case1

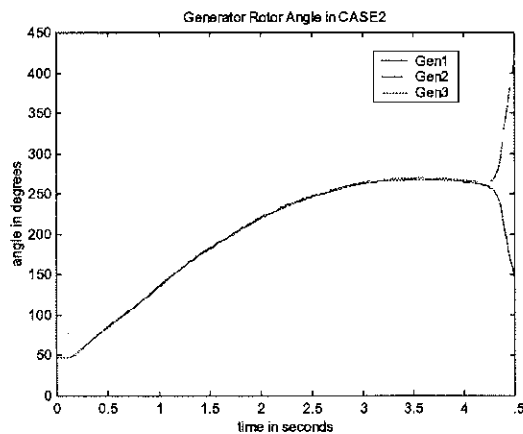


Figure 3. Rotor angle curves for generator 1, 2 and 3 of case2

It is observed from Figure 2 that the rotor angle responses of generators 1, 2 and 3 are identical and they are perfectly coherent. This is because all three generators have identical system parameters and network configurations so that they see exactly the same amount of accelerating power triggered by the disturbance at bus 5. On the other hand, it is observed from Figure 3 that only generators 1 and 2 have identical rotor angle responses while generator 3 is not coherent with generators 1 and 2. The electrical power output of a generator depends on the transmission line reactance as well as voltage magnitude. Due to the AVR control action, generators 1 and 2 with AVR and generator 3 without AVR in the case 2 see different amounts of accelerating power caused by the disturbance beyond bus 4 even though they have identical system parameters and network configurations. This simulation results show that locations of AVR affect the coherency of generators which have identical system parameters and network configurations.

The following example illustrates how different speeds of AVR influence the coherency of generators. Generators 1, 2 and 3 have the identical machine inertia and transient reactance. They have symmetrical network configurations and are all connected to bus 10 with the same line impedance.

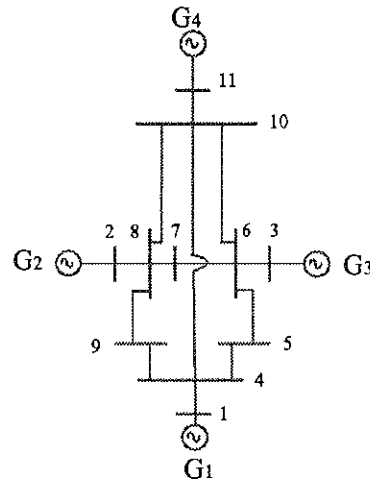


Figure 4. 4-machine 11-bus system

Two test cases are also considered to investigate the effect of speed of AVR on the coherency of generators. In case 3 it is assumed that generators 1, 2 and 3 have identical exciters, i.e., IEEE type DC1. On the other hand, it is assumed in case 4 that IEEE type ST3 model exciter is available at generator 3 while IEEE type DC1 exciters are available at generators 1 and 2. Note that speed of exciter at generator 3 is much faster than those of generators 1 and 2. The rotor angle responses of generators were simulated in the time domain for a 3-phase fault at bus 10. Figures 5 and 6 show the rotor angle responses of generators for case 3 and case 4, respectively.

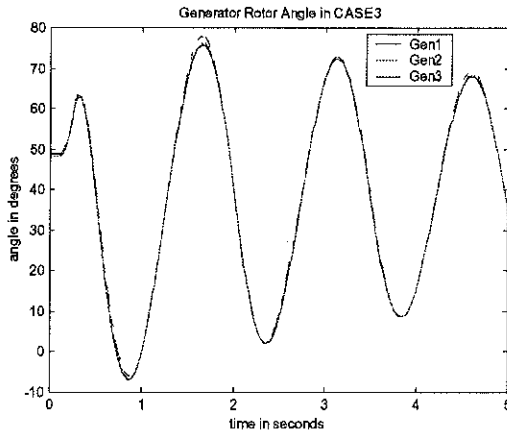


Figure 5. Rotor angle curves for generator 1, 2 and 3 of case3

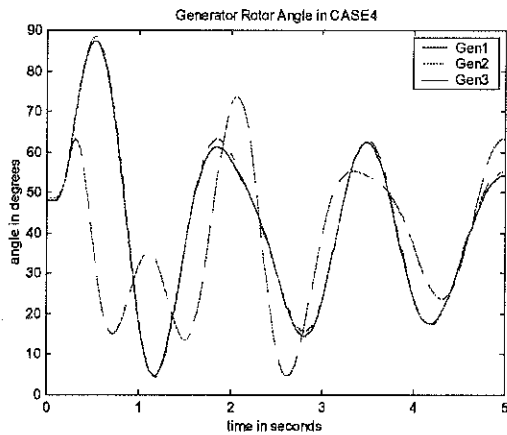


Figure 6. Rotor angle curves for generator 1, 2 and 3 of case4

As can be seen in Figure 5, all three generators are perfectly coherent in case 3. It is shown in Figure 6 that generator 3 is not coherent with generators 1 and 2 at the beginning of simulations. This is because the exciter at generator 3 acts faster than those of generators 1 and 2 after disturbance is applied to the system and reduces first swing of generator 3. All three generators tend to get more coherent as effect of speed of AVR control action on rotor oscillations decreases. This simulation results show that speed of AVR affects the rotor angle response of generators mostly in the first swing after the disturbance is applied to the system.

### III. COHERENCY IDENTIFICATION TECHNIQUE INCORPORATING VOLTAGE DYNAMICS

The rotor angle response of the generator is used to measure coherency between generators since coherent generators have similar rotor angular swings for a disturbance. In order to determine the rotor angular swing of generators in a power system, a set of differential equations

describing the dynamic behaviors of the power system has to be solved simultaneously with a set of algebraic equations.

$$\begin{aligned}\dot{x} &= f(x, z) \\ 0 &= g(x, z)\end{aligned}\quad (1)$$

where  $x$  is the state vector and  $z$  is a vector of algebraic variables.

Most of coherency identification techniques employ the following classical model of generators for identification of coherent generators based on the assumption that excitation system only affect the damping of the transients but do not significantly change natural frequencies and mode shapes of the system responses [3].

$$\frac{d}{dt}\delta_i = \omega_i \quad (2)$$

$$M_i \frac{d^2}{dt^2}\delta_i = P_{mi} - P_{ei} - D_i \omega_i \quad (3)$$

The classical model of generators is not appropriate to study the dynamic interactions of generator and voltage control devices since only the rotor angle modes can be obtained from linearized system model defined by (2) and (3). To incorporate voltage dynamics of the original system, state variables of differential equations should be expanded to represent system voltages and voltage control devices. The differential equations for the two-axis model and a simple exciter model are given by

$$\dot{\delta}_i = \omega_i - \omega_s \quad (4)$$

$$M_i \dot{\omega}_i = T_{mi} - (I_{di} E'_{di} + I_{qi} E'_{qi}) - D_i \omega_i \quad (5)$$

$$T_{doi} \dot{E}'_{qi} = E_{FDi} - E'_{qi} - (x_{di} - x'_{di}) I_{di} \quad (6)$$

$$T_{qoi} \dot{E}'_{di} = -E'_{di} - (x_{qi} - x'_{qi}) I_{qi} \quad (7)$$

$$T_{Ai} \dot{E}_{Fdi} = -E_{Fdi} + K_{Ai} (V_{ref} - V_{ti}) \quad (8)$$

By linearizing the above dynamic equation at an initial operating point, the following linearized system model can be obtained.

$$\dot{X} = AX + B\Delta V \quad (9)$$

$$0 = CX + D\Delta V \quad (10)$$

where  $X$  is the state vector of machine angle, speed and other state variables associated with voltage and  $\Delta V$  is a vector of bus voltage deviations.

Based on the above state-space model that takes into account generator AVR control actions and load bus voltage variations, a coherency measure between generators is proposed in order to deal with voltage-related scenarios.

If D is invertible,

$$\Delta V = -D^{-1}CX \quad (11)$$

Therefore,

$$\dot{X} = (A - BD^{-1}C)X = A_{sys}X \quad (13)$$

Time response of the i-th rotor angle is given by

$$x_i(t) = \sum_{k=1}^N u_{ik} a_k e^{\lambda_k t} \quad (14)$$

where  $u_{ik}$  is the i-th entry of the k-th eigenvector  $U_i$  of  $A_{sys}$  and coefficients  $a_k$  depends on initial operating conditions.

Inter-area modes of generators as well as the modes that characterize voltage dynamics are essential in identification of groups of coherent generators and the other modes such as local modes of generators can be ignored in equation (14). Once inter-area modes of generators as well as the modes that characterize voltage dynamics are identified by modal analysis, the following modal responses for generator i and j are obtained to identify groups of coherent generators:

$$x_i = u_{i1}a_1e^{\lambda_1 t} + u_{i2}a_2e^{\lambda_2 t} + \dots + u_{im}a_me^{\lambda_m t} \quad (15)$$

$$x_j = u_{j1}a_1e^{\lambda_1 t} + u_{j2}a_2e^{\lambda_2 t} + \dots + u_{jm}a_me^{\lambda_m t} \quad (16)$$

It is shown in our previous work [7] that the accuracy of coherency identification for dynamic reduction can be improved when initial operating conditions of a power system are considered. The following measure is proposed for identification of coherent groups of generators.

$$\theta_{ij} = \cos^{-1} \frac{w_i \cdot w_j^T}{\|w_i\| \cdot \|w_j\|} \quad (17)$$

where

$$w_i = (u_{i1} \times a_1, \dots, u_{ik} \times a_k, \dots, u_{im} \times a_m)$$

$$w_j = (u_{j1} \times a_1, \dots, u_{jk} \times a_k, \dots, u_{jm} \times a_m)$$

The row vectors  $w_i$  and  $w_j$  contain  $u_{ik} \times a_k$  as the elements that represent the modal response for generator i and j. Once the vectors  $w_i$  and  $w_j$  are formed, one can inspect the closeness of time domain response of rotor angles by calculating the vector angle between two vectors. If two row vectors lie along the same line, the vector angle between two row vectors is zero. Hence, if  $\theta_{ij}$  is close to zero, generator i and j are considered to be coherent.

The proposed coherency identification technique will be illustrated with the simulation examples. Consider case 3 and case 4 in section II to investigate the effect of AVR control action on the proposed coherency measure. The selected system modes of case 3 are listed in the Table 3.1.

Table 3.1. Selected Mode Identification of Case 3

|        | Eigenvalue              | Frequency (Hz) | Damping ratio |
|--------|-------------------------|----------------|---------------|
| Model1 | $-0.0900 \pm j 5.1399$  | 0.818          | 0.0175        |
| Model2 | $-0.0244 \pm j 6.7394$  | 1.0726         | 0.0036        |
| Model3 | $-0.0408 \pm j 6.7633$  | 1.0764         | 0.006         |
| Model4 | $-16.9436 \pm j 8.4140$ | 1.3391         | 0.8956        |
| Model5 | -27.2690                | 0              | 1             |
| Model6 | -27.4258                | 0              | 1             |

Modes 1, 2 and 3 are identified as inter-area modes of the system by inspecting the participation factor of state variables obtained by modal analysis. It is also found by modal analysis that modes 4, 5 and 6 of systems are related to AVR control action of Generators 1, 2 and 3. Based on these 6 modes, vector W is formed whose row vector represents the modal response for generator i. Then, the coherency measures between generators 1, 2 and 3 with the proposed coherency measure are all  $0^\circ$  ( $\theta_{12} = \theta_{23} = \theta_{31} = 0^\circ$ ), which means that generators 1, 2 and 3 are perfectly coherent. On the other hand, the coherency measures between generators 4 and 1(2, or 3) are all ( $\theta_{41} = \theta_{42} = \theta_{43} = 180^\circ$ ), which means that generators 4 is in anti-phase with Generators 1, 2 and 3.

The selected system modes of case 4 are listed in the Table 3.2.

Table 3.2. Selected Mode Identification of Case4

|        | Eigenvalue              | Frequency (Hz) | Damping ratio |
|--------|-------------------------|----------------|---------------|
| Model1 | $-0.0792 \pm j 4.8233$  | 0.7677         | 0.0164        |
| Model2 | $-0.4017 \pm j 6.2687$  | 0.9977         | 0.0640        |
| Model3 | $-0.2079 \pm j 6.6278$  | 1.0548         | 0.0314        |
| Model4 | $-8.7184 \pm j 10.1963$ | 1.6228         | 0.6499        |
| Model5 | $-8.8203 \pm j 10.2612$ | 1.6331         | 0.6519        |
| Model6 | -23.871                 | 0              | 1.0000        |

Modes 1, 2 and 3 are identified as inter-area modes of the system whereas modes 4, 5 and 6 of systems are related to the AVR control action. The coherency measure between generators 1 and 2 is  $0^\circ$  ( $\theta_{12} = 0^\circ$ ) while coherency measure between generators 3 and 1(or 2) is  $22.69^\circ$  ( $\theta_{31} = \theta_{32} = 22.69^\circ$ ). On the other hand, the coherency measures between generators 4 and 1 (or 2) are all ( $\theta_{41} = \theta_{42} = 175.41^\circ$ ). The coherency measure between generators 4 and 3 is  $164.84^\circ$  ( $\theta_{43} = 164.84^\circ$ ). Generators 3 and 1(or 2) are not perfectly coherent any more due to the different speeds of AVR.

The proposed coherency identification technique uses the K-means algorithm [8] that performs iterative searches for identifying coherent groups of generators using the proposed coherency measure. The proposed coherency identification technique consists of the following two major procedures.

- Relevant mode identification for coherency of generators
- Coherency grouping based on selected modes

The first procedure uses modal analysis to identify inter-area modes and modes that characterize AVR control action. The second procedure uses the K-means algorithm that performs iterative searches for identifying coherent groups of generators based on modes selected in the first procedure. The proposed coherency identification algorithm can be summarized as follows:

#### Mode identification

Step1: Choose the number of coherent groups  $K$ .  $1 < K < N$

Step2: Obtain the matrix  $A$  by linearizing system equation (1) about the initial operating point.

Step3: Identify modes that are mostly influenced by state variables related to AVR control action as well as inter-area modes. This is performed by inspecting participation factors of state variables to modes obtained by modal analysis.

#### Coherency Grouping [7]

Step4: Form a normalized row vector  $w_i$  which represents the modal response of a generator 'i' for  $i = 1, \dots, N$ .

Step5: Randomly form an initial centroid vector of the  $k$ -th group  $\mu_k$  for  $k = 1, \dots, K$ .

Step6: Find the closest centroid vector  $\mu_k$  to each vector  $w_i$  by computing following closeness measures between vector  $w_i$  and  $\mu_k$ .

$$\theta_{w_i \mu_k} = \cos^{-1} \frac{w_i \cdot \mu_k^T}{\|w_i\| \cdot \|\mu_k\|} \quad \text{for } k = 1, \dots, K$$

Assign the generator 'i' to the  $k$ -th group.

Step7: In the  $j$ -th iteration, update the centroid vector  $\mu_k$  by computing the means of all vectors in the group 'k' and normalize it.

$$\mu_k^{(j)} = \frac{1}{N_k^{(j)}} \sum_{w \in G_k} w \quad \text{for } k = 1, \dots, K \quad (16)$$

Step8: Stop if there is no more reassignment of any generator from one group to another, i.e.,  $\mu_k^{(j+1)} = \mu_k^{(j)}$  for all  $k = 1, \dots, K$ . Else go to Step 6 and repeat the algorithm.

## IV. CASE STUDY

For verification and validation of the proposed coherency identification technique, numerical testing is conducted with the NPCC 48-machine test system. The system consists of 48 generators, 140 buses and 233 transmission lines. Figure 4.1 shows a study area of the NPCC 48-machine test system where dynamic responses of generators are to be studied in response to disturbances. Generators 1 to 9 in the study area are retained in full, whereas 39 generators in external area are replaced with 9 (external) equivalent generators. Generators equipped with exciters in the external area are listed in the Table 4.1. along with their exciter types.

Table 4.1. List of external generators with exciters

| Generators          | Exciter type      |
|---------------------|-------------------|
| 10-14, 16-22, 28-30 | All IEEE type DC1 |

Cases with and without considering AVR control action on coherency of generators are compared.

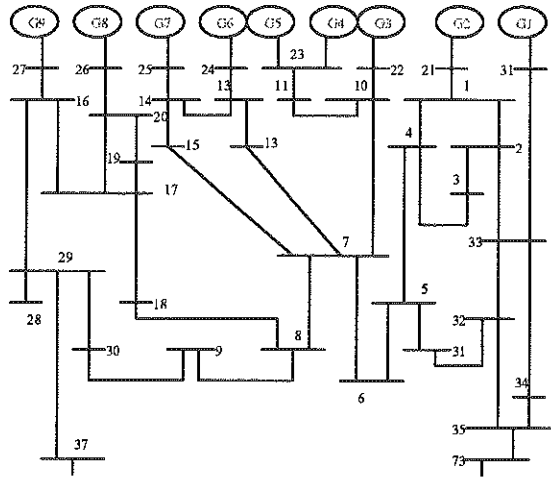


Figure 4.1: NPCC 48-machine test system

The proposed coherency method is applied to obtain 9 coherent groups of generators for the external area. The resulting 9 coherent groups are shown in the Table 4.2. when the proposed coherency method uses those modes, which characterize AVR control, as well as inter-area modes of the system for identifying coherency of generators.

Table 4.2. Coherent Groups using Proposed Coherency Algorithm

| Group | Generators            | Group | Generators |
|-------|-----------------------|-------|------------|
| 1     | 11, 12                | 6     | 15, 23     |
| 2     | 18, 20                | 7     | 34, 35, 36 |
| 3     | 16-19, 21, 22, 31, 33 | 8     | 32, 37-42  |
| 4     | 10, 13, 14, 24-26     | 9     | 43-48      |
| 5     | 27-30                 |       |            |

On the other hand, the Table 4.3 shows the resulting 9 coherent groups when the proposed coherency method uses only inter-area modes of the system for identifying coherency of generators.

Table 4.3. Coherent Groups using Coherency Algorithm

| Group | Generators     | Group | Generators             |
|-------|----------------|-------|------------------------|
| 1     | 10, 24, 25, 26 | 6     | 39                     |
| 2     | 11, 12, 33     | 7     | 32, 37, 38, 40, 41, 42 |
| 3     | 13-23, 31      | 8     | 43-47                  |
| 4     | 27-30          | 9     | 48                     |
| 5     | 34, 35, 36     |       |                        |

A comparison of Table 4.2 and Table 4.3 shows that the grouping results shown in Table 4.2 have more tendency to classify generators with exciters into the same group than those in Table 4.3. This is because the former coherency groups were obtained by using AVR related modes as well as inter-area modes while the latter coherency groups was obtained by considering only inter-area modes.

Based on the obtained coherent groups, 39 generators in the external area are replaced with 9 equivalent generators. Coherent generators are aggregated using internal-node method [9]. After generator aggregation, the reduced equivalent system consists of total 18 generators, which are about 37.5% of 48 generators of the original system. In order to evaluate the accuracy of the obtained coherency-based equivalent system, hence, the rotor angle responses of generators in the study area are simulated in the time domain for a 3-phase fault on the line between buses 3 and 4. The Matlab Power System Toolbox is used for computation.

Figure 4.2 shows rotor angle responses of generator 1 with the full system and both of the coherency-based equivalent systems. Coherency-based equivalent system 1 represents the equivalent system obtained from coherent groups in the Table 4.2 whereas coherency-based equivalent system 2 represents the equivalent system obtained from coherent groups in the Table 4.3.

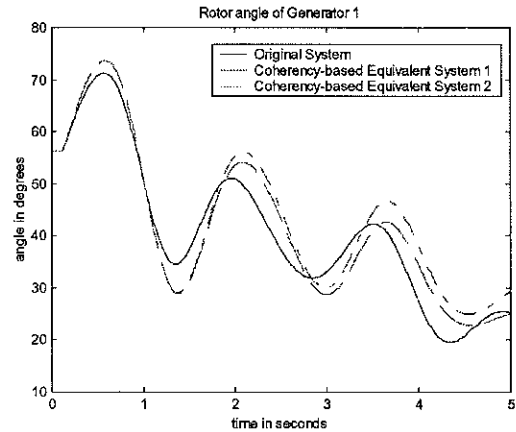


Figure 4.2. Rotor Angle Curves for Generators 1

Figure 4.3 shows terminal voltage of generator 1 with the full system and both of the coherency-based equivalent systems.

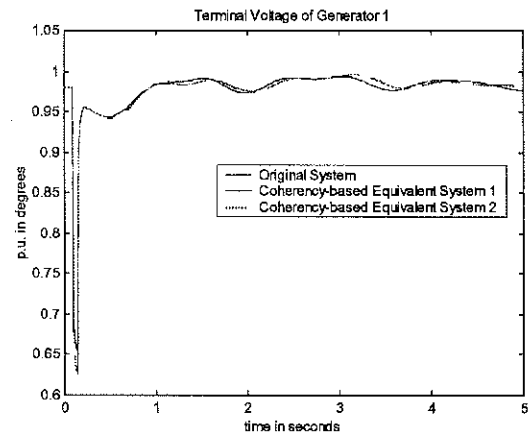


Figure 4.3. Terminal Voltage Magnitude of Generator 1 at bus 36

It is observed from Figure 4.2 that, based on the rotor angle responses, Coherency-based equivalent system 1 is closer to that of original system a few seconds after the disturbance is applied than coherency-based equivalent system 2. This is because AVR control has a few seconds time delay and its effect on coherency becomes more dominant a few seconds after the disturbance is applied. This result shows that the accuracy of coherency-based equivalent system can be improved if the voltage characteristics of the original system such as AVR control action are considered. As can be seen in Figure 4.3, the terminal voltages of generator 1 obtained from simulation with both of equivalent systems are very close to the actual terminal voltages of generator 1 in the original system.

## V. CONCLUSIONS



The paper presents our results on how speed and locations of voltage control devices such as AVR affect the coherency of generators. Modal analysis is used to pinpoint inter-area oscillation modes and modes that characterize AVR control action. The proposed coherency identification technique can capture the effect of AVR control action on coherency by analyzing eigenvectors associated with AVR related modes of the system.

Once relevant modes are identified, the proposed method uses the K-means algorithm that performs iterative searches for obtaining the pre-specified number of coherent groups of generators. The method described in the paper is tested on the NPCC 48 system. Test results show that the accuracy of coherency-based equivalent system can be improved if the voltage characteristics of the original system such as AVR control action are considered.

## VI. ACKNOWLEDGEMENTS

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## VIII. BIOGRAPHIES

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# Exploring Power System Loadability Surface with Optimization Methods

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**Abstract:** In this paper we discuss the properties of special points on the loadability surface, and their impact on voltage stability analysis of power systems. The points considered include the corner points where multiple loadability limit branches intersect, as well as a point of intersection of fold and Hopf bifurcation surfaces. Following this, a method to identify easily the closest loadability limit to an operating condition is given, based on a reasonable assumption. Violation of this assumption is seen to correspond to an angle stability constrained system. Finally, application results on an existing, practical size, power system are given.

**Keywords:** Voltage stability, loadability limits, optimization, bifurcation surface, normal vector, closest loadability.

## 1. Introduction

As power systems are getting more and more heavily loaded under open market conditions, voltage security assessment (VSA) tends to become an indispensable tool for long-term transmission planning studies, for day-to-day operational planning and for real-time operation. Since voltage stability is a problem related to maximum power transfer, the computation of loadability limits, as well as the determination of secure operation limits [1] become increasingly important aspects of VSA. Some aspects, however, of loadability limits, as well as certain important properties of the surface they form in parameter space (which we call loadability surface) have not yet been fully investigated and understood.

It is well known that the loadability limits may coincide with static bifurcation points (where the state Jacobian becomes singular). The voltage instability phenomena arising in such cases have been associated in the power system literature [1]-[8] to the most common static bifurcation, the *saddle-node bifurcation*.

There are other cases, however, where a loadability limit is reached through an abrupt change caused by a switching action in the system. A typical example of switching action, after which the system may exhaust its loadability margin, is the enforcement of generator overexcitation limits. This phenomenon has been called in the literature “immediate change of stability” [9], or “limit induced bifurcation” [10]. Switching loadability limits have been investigated also in [11].

Another possible concern is that a stability limit may be encountered prior to the loadability limit, particularly in systems where an oscillatory instability is possible. In this case, the stable operating region of the system is bounded by the stability limit and not by the loadability surface.

In this paper we investigate several properties of the loadability surface and in particular of special points where branches of loadability limits intersect with one another, or with other bifurcation branches. To this end, we review the results reported in [12] to clarify the relationships between static bifurcation points and loadability limits and those in [13] that identify loadability limits due to switching actions, modelled using inequality constraints. Following this, a generalized normal vector to the loadability surface is introduced at non-smooth points where multiple loadability branches intersect. Similarly to the case of the bifurcation surface [5], this vector can be used to provide the direction for corrective measures, as in [14].

We then investigate the properties of the intersection points of the loadability surface with a Hopf bifurcation surface. Near this intersection the limiting instability changes from monotonic to oscillatory and a detailed dynamic analysis of the power system becomes necessary.

The final problem investigated is that of obtaining the closest loadability limit to a particular operating point and a simple solution to this problem is given subject to certain assumptions regarding the structure of the loadability surface. These assumptions are not always applicable, as demonstrated by a counterexample, which, however, refers to a case where the limiting stability factor is, at least partly, an angle instability problem.

The method developed is applied to the Hellenic Interconnected Power System, for which a non-smooth loadability limit is identified and analyzed using the generalized normal vector defined in the paper.

## 2. Definitions and assumptions

### A. Smooth model

A power system is modelled by a set of nonlinear differen-

tial equations subject to algebraic constraints:

$$\dot{z} = h(z, y, p) \quad (1)$$

$$0 = g(z, y, p) \quad (2)$$

where  $z \in Z \subset R^\ell$  is the power system state vector, which typically includes generator, controller, and load state variables,  $y \in Y \subset R^k$  are the algebraic variables associated with the network voltages (magnitudes and phase angles) and  $p \in P \subset R^m$  is a vector of parameters, such as load demands and generator setpoints. We assume that  $h : Z \times Y \times P \rightarrow R^\ell$  and  $g : Z \times Y \times P \rightarrow R^k$  are differentiable.

We also assume that the Jacobian  $D_y g = \partial g / \partial y$  remains nonsingular in  $Z \times Y \times P$ , so that (1)-(2) can be locally reduced to a system of  $\ell$  ODEs.

The dynamics modelled in (1) can include either short-term or long-term state variables, in which case we refer to the *short-term* or *long-term* model respectively. In most cases in this paper we will consider long-term dynamics, but the analysis applies to short-term models as well.

In (1)-(2) we neglect the limits imposed on generators and in particular the overexcitation limits. We will call this set of equations the *smooth* model, in contrast with the *switching* model, which includes generator overexcitation (and possibly other) switching actions, and will be introduced in the next subsection.

We define  $x \in X \subset R^n$ , where  $n = k + \ell$ , and  $f : X \times P \rightarrow R^n$  as:

$$x^T = [z^T \ y^T] \quad f^T = [h^T \ g^T] \quad (3)$$

We will concentrate on the equilibrium equations of the system (1)-(2), which are written as:

$$f(x, p) = 0 \quad (4)$$

Note that any equivalent reduced set of equilibrium conditions can be used in place of (4) for static analysis purposes.

A solution  $x_o$  of (4) for  $p = p_o$  is called an *equilibrium*, or simply a *steady state* of the system.

We define a *loadability limit*  $(\hat{x}, \hat{p})$  as a solution of the constrained optimization problem:

$$\max_{x \in X, p \in P} \{\zeta(p) : f(x, p) = 0\} \quad (5)$$

where  $\zeta(p)$  is a continuous scalar function depending only on the parameters  $p$ , such that  $\hat{p}$  is not a solution of the unconstrained problem:

$$\max_{p \in P} \{\zeta(p)\} \quad (6)$$

For example if the parameter vector includes the load demand increases  $\Delta P_i$  at each load bus  $i$  belonging to an area  $A$ , then by choosing:

$$\zeta(p) = \sum_{i \in A} \Delta P_i$$

the solution  $\zeta(\hat{p})$  of (5) gives the active power loading margin in area  $A$ . Similarly the function:

$$\zeta(p) = \sum \Delta Q_i$$

will provide the reactive power margin of a system as in [15].

For an initial operating point  $(x_o, p_o)$  and a *direction of stress*  $d \in R^m$  in parameter space, such that  $p$  is constrained to be:

$$p = p_o + \tau d \quad (7)$$

and  $\tau \in R$ , we define a *loadability limit along direction  $d$*  as the solution  $(\hat{x}, \hat{\tau})$  of the constrained problem

$$\max_{x \in X, \tau \in R} \{\tau : f(x, p_o + \tau d) = 0\} \quad (8)$$

The value  $\hat{\tau}$  at the solution of (8) gives the *loadability margin* along direction  $d$ .

The locus of all loadability limits in parameter space defines the *loadability surface*  $\mathcal{L}$  of the power system. The loadability surface may have multiple branches, the outmost of which bounds the *feasibility region*, i.e. the region in parameter space, where operating points exist.

A *static bifurcation point* is a point  $\hat{p}$  in parameter space, in the neighborhood of which the number of solutions of (4) changes. The strict definition can be found in [12, 16]. The necessary condition for a static bifurcation is that the *state Jacobian*:

$$A = D_z h - D_y h (D_y g)^{-1} D_z g \quad (9)$$

calculated at the equilibrium  $(\hat{x}, \hat{p})$  is *singular*. Otherwise, by the implicit function theorem, there would exist one single smooth branch of equilibria through the point  $\hat{p}$  and, therefore, the number of equilibria could not change.

Using Schur's formula:

$$\det D_x f = \det A \det D_y g$$

and since we have assumed  $\det D_y g \neq 0$ , the singularity of  $A$  is equivalent to that of  $D_x f$ . Also, as shown in [1], the eigenvector corresponding to the zero eigenvalue of  $A$  consists of the elements corresponding to the state variables  $z$  of the respective eigenvector of  $D_x f$ .

The most common static bifurcation is the *Saddle-Node Bifurcation* (SNB) which is characterized by a simple zero eigenvalue of the state Jacobian  $A$ . Moreover, for an SNB the following transversality conditions must hold [17]:

- (i)  $D_p f(\hat{x}, \hat{p})^T w \neq 0$
- (ii)  $v^T \left[ \sum_{i=1}^n w_i \frac{\partial^2 f_i(\hat{x}, \hat{p})}{\partial x^2} \right] v \neq 0$

where  $w$  and  $v$  is the left and right eigenvector corresponding to the zero eigenvalue of  $D_x f(\hat{x}, \hat{p})$ .

A slight generalization of SNB is the *fold* bifurcation [17], for which the simple zero eigenvalue condition is replaced by that of  $A$  being of rank  $\ell - 1$ . Of particular interest is the case of a fold bifurcation with a double zero eigenvalue of the state Jacobian, which has algebraic multiplicity 2 and geometric multiplicity 1. The state Jacobian is then characterized by a Jordan canonical block of the form:

$$\begin{bmatrix} 0 & 1 \\ 0 & 0 \end{bmatrix}$$

Such a fold bifurcation with a double zero eigenvalue of  $A$  is a co-dimension 2 bifurcation, since typically two parameters have to be varied to achieve the above form of a Jordan block.

In [12] it was proven that all loadability limits of the form (5) correspond to static bifurcation points of the system (1)-(2). It can also be shown that a fold bifurcation always corresponds to a loadability limit. However, other types of static bifurcations, e.g. cusp bifurcations, do not correspond to loadability limits [18]. Thus, when generator limits are not considered, all loadability limits belong to the *static bifurcation surface*  $\Sigma$  [5, 14] defined as the equilibrium points satisfying (4) and the singularity condition:

$$\det D_x f(x, p) = 0 \quad (10)$$

In contrast, *dynamic bifurcations* are not linked to a singularity of the Jacobian  $D_x f$ , and the number of equilibrium points does not change at the bifurcation. The only dynamic bifurcation of co-dimension 1 is the *Hopf* bifurcation characterized by an oscillatory instability brought about by the interaction between an equilibrium and a limit cycle, either disappearing at, or emanating from the bifurcation.

The necessary condition for a Hopf bifurcation is:

$$\det[A - j\omega I] = 0 \quad (11)$$

This is a complex equation that can be split in two real ones, whereas a new variable  $\omega$  is introduced. Therefore, the points in  $m$ -dimensioned parameter space satisfying (11) form in general an  $(m - 1)$ -dimensional manifold that we will call *Hopf bifurcation surface*.

A Hopf bifurcation, like all dynamic bifurcations, does not correspond to a loadability limit. However, due to the oscillatory instability, the Hopf bifurcation surface separates

the stable from the unstable equilibria and consequently it forms a boundary of the *stable operating region* in parameter space. As we will see in Section 4, the importance of the fold bifurcation with a double zero eigenvalue of  $A$ , is that it lies on the intersection of the Hopf bifurcation and the loadability surface.

### B. Switching system

In order to represent the overexcitation limiters (OEL) of synchronous generators (or other controllers imposing similar hard limits) the smooth system of differential equations (1) and/or algebraic constraints (2) has to be modified. Thus for a number of  $\ell_s$  state variables we assume the following conditional relations, instead of (1):

$$\dot{z}_i = h_{i1}(z, y, p) \quad \text{if } h_{i2}(z, y, p) > 0 \quad (12)$$

$$\dot{z}_i = h_{i2}(z, y, p) \quad \text{if } h_{i2}(z, y, p) < 0 \quad (13)$$

The switching conditions between (12) and (13) when:

$$h_{i2}(z, y, p) = 0$$

are the following:

$$\dot{z}_i = h_{i1}(z, y, p) \quad \text{if } h_{i1}(z, y, p) < 0 \quad (14)$$

$$\dot{z}_i = h_{i2}(z, y, p) = 0 \quad \text{if } h_{i1}(z, y, p) \geq 0 \quad (15)$$

The representation (12)-(13) implies that the order of the system remains the same before and after the switching. In general, however, this is not necessarily true as the system after the switching could be represented by an algebraic constraint, or even by a higher order system. Thus, the representation (12)-(13) should be interpreted as including a suitable number of dummy state variables and/or trivial differential equations before, or after the switching.

For detailed modelling of OEL devices refer to [1, 19, 20]. As a simple illustrative example we will assume here a generator with a first order AVR, and a takeover integral OEL, in which case the state  $z_i$  is the generator excitation EMF  $E_f$  and the functions  $h_{i1}$  (AVR), and  $h_{i2}$  (OEL) are given by:

$$h_{i1} = \frac{1}{T_A} [-E_f + K(V_r - V)] \quad (16)$$

$$h_{i2} = \frac{1}{T_x} (E_f^{lim} - E_f) \quad (17)$$

where  $V_r$  and  $V$  are the generator reference and terminal voltage respectively,  $K$  is the AVR gain and  $E_f^{lim}$  is the upper limit corresponding to the permissible field current for continuous operation.

The equilibrium conditions for the switching model (12)-(15) are the following:

$$h_{i1}(z, y, p) = 0 \quad \text{with } h_{i2}(z, y, p) \geq 0 \quad (18)$$

$$h_{i2}(z, y, p) = 0 \quad \text{with } h_{i1}(z, y, p) \geq 0 \quad (19)$$

The first condition is an equilibrium of (12). The second condition is identical to (15), where the inequality is necessary to avoid switching back to (12). Note that at equilibrium one of  $h_{i1}$ ,  $h_{i2}$ , or both will be zero. The latter condition occurs at an equilibrium, where switching conditions hold.

The type of limit considered is a “nonwindup” [19] or “state” limit [10]. For other types of switching actions, such as “windup” limits [10], or overcurrent switching, similar expressions can be introduced for the algebraic constraints (2).

As the scope of this paper is the exploration of the loadability surface, we are mostly interested in the equilibrium conditions, which for the switching system can be written as in [1]:

$$\varphi(x, p) = 0 \quad (20)$$

$$f_{i1}(x, p)f_{i2}(x, p) = 0 \quad i = 1, \dots, n_s \quad (21)$$

$$f_{i1}(x, p) \geq 0 \quad i = 1, \dots, n_s \quad (22)$$

$$f_{i2}(x, p) \geq 0 \quad i = 1, \dots, n_s \quad (23)$$

where  $\varphi$  are  $n - n_s$  smooth functions and  $f_1, f_2$  are also smooth.

It is clear from (21) that at certain equilibrium points both inequalities (22) and (23) may hold as equalities for the same  $i$ . At these equilibrium points switching conditions between  $f_{i1}$  and  $f_{i2}$  occur. These have been called “breaking points” in [1] with reference to the representation of such points on PV curves. We will introduce here the more general term *switching points* for these equilibria. At a switching point, the continuity is guaranteed, but the DA system is no longer smooth, due to the switching from  $f_{i1}$  to  $f_{i2}$ , or vice versa.

The loadability limits of the switching system are defined similarly to (5) as solutions  $(\hat{x}, \hat{p})$  of the following optimization problem [1]:

$$\max_{x \in X, p \in P} \{\zeta(p) \text{ subject to: (20) – (23)}\} \quad (24)$$

where, as before,  $\zeta(p)$  is a continuous scalar function, such that  $\hat{p}$  is not a solution of the unconstrained problem (6).

The solutions of this problem will yield the loadability limits, regardless of whether they are static bifurcations, or switching points. A switching point that is a loadability limit has been called *limit induced static bifurcation* in [10]. Note, however, that at these points the Jacobian  $D_x f$  is in general nonsingular both for  $f_1$  and  $f_2$ . Thus, the necessary condition (10) for a static bifurcation is not satisfied. For this reason, we will avoid here to refer to these loadability limits as bifurcations, and we will use instead the term *switching loadability limits*.

### 3. Normal vector to loadability surface

#### A. Normal vector at switching loadability limits

As discussed in Section 2, the solutions  $\hat{p}$  of (24) for all possible choices of  $\zeta(p)$  belong to the loadability surface  $\mathcal{L}$ . Note that  $\mathcal{L}$  may consist of multiple branches or segments. In general, the loadability surface consists partly of bifurcation points belonging to  $\Sigma$ , and partly of switching loadability limits. The outer branch of the loadability surface in parameter space forms a boundary of the feasibility region, where operating points satisfying (20)–(23) exist.

When the loadability surface  $\mathcal{L}$  coincides with  $\Sigma$ , it is well known [1, 5] that it is smooth, and that its normal vector is related to the left eigenvector corresponding to the zero eigenvalue of the Jacobian  $D_x f$ . The normal vector to the loadability surface  $\mathcal{L}$  is also related (as explained in [13]) to the Lagrange multipliers of the optimization problem (24), when a single switching occurs at the loadability limit. In this section we will investigate also the case of loadability limits, due to simultaneous switching of multiple devices.

Let  $\psi$  denote the set of all functions  $\varphi, f_1, f_2$  that are equal to zero at the loadability limit. Thus the set of equations holding at the loadability limit is written as:

$$\psi(x, p) = 0 \quad (25)$$

The dimension of  $\psi$  is  $n + n'$ , where  $n'$  is the number of switching devices at the loadability limit. If only one of (22)–(23) for each  $i$  holds as an equality at the loadability limit, then  $n' = 0$  and (25) will consist of exactly  $n$  equations. In this case the Jacobian  $D_x \psi$  will be square and singular. If for a single switching device  $i$  both (22) and (23) hold as equalities at the loadability limit, then  $n' = 1$  and the Jacobian  $D_x \psi$  will be rectangular with dimensions  $(n + 1) \times n$ . In both of the above cases, we can define the vector  $w$ , as the left singular vector of  $D_x \psi$  corresponding to its zero singular value:

$$D_x \psi^T w = 0 \quad (26)$$

When the loadability limit is a bifurcation,  $w \in R^n$  coincides (in the generic case of a fold bifurcation) with the left eigenvector of the singular square Jacobian corresponding to the zero eigenvalue [1]. For a switching loadability limit, in the generic case where  $D_x \psi$  has rank  $n$ , there exists one zero singular value and thus a single  $w \in R^{n+1}$ .

Consider now a switching loadability limit where more than one components are under switching conditions ( $n' > 1$ ), i.e. both (22) and (23) hold as equalities for  $i = 1, \dots, n'$ . Then, for each switching condition  $i$ , a separate smooth branch of loadability limits  $\mathcal{L}_i$  exists and the loadability limit under consideration is at the intersection of all these branches. Moreover, considering a separate



**Table 1:** Test system data (pu 100 MVA basis)

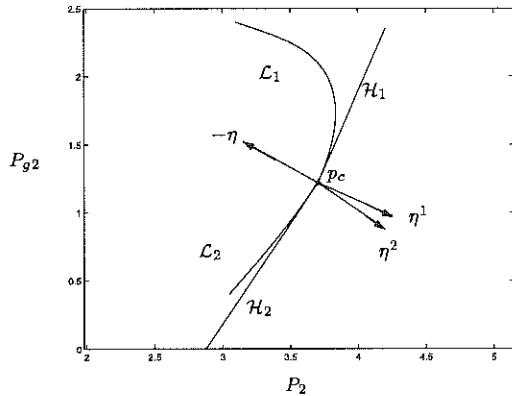
|                   |                   |             |          |
|-------------------|-------------------|-------------|----------|
| $X_{15} = X_{24}$ | $X_{34}$          | $X_{45}$    | $r$      |
| 0.032             | 0.005625          | 0.068       | 1.04     |
| $X_d = X_q$       | $V_{1o} = V_{2o}$ | $E_f^{lim}$ | $K$      |
| 0.8               | 1.0               | 2.5968      | 100      |
| $P_1 = Q_1$       | $P_{2o} = P_{go}$ | $B$         | $Q_2$    |
| 0.0               | 2.0               | 0.25        | $0.5P_2$ |

load  $P_2$  and the generation  $P_{g2}$  of the local generator. It is also assumed that the load  $P_2 + jQ_2$  is restoring to constant power after a disturbance (e.g. through LTC control). Thus the parameter vector is:

$$p = [P_2 \ P_{g2}]^T$$

Both generators are represented with a first order AVR and overexcitation limiter as in equations (16), (17).

For low values of the local generation  $P_{g2}$  the loadability limit is due to the power transfer from generator 1, and thus the loadability margin increases with  $P_{g2}$ . Fig. 2 shows a part of the loadability surface of the two generator system including the corner point  $p_c$ , where the two loadability limit branches  $\mathcal{L}_1$  and  $\mathcal{L}_2$  intersect.

**Figure 2:** Generalized normal vector at a corner point

Consider a constant value of  $P_{g2}$  above that corresponding to the intersection point  $p_c$  of the two loadability branches. In this case, as the load  $P_2$  increases generator 2 will be the first to reach overexcitation. For a further increase of the load  $P_2$ , a loadability limit is reached at the point where generator 1 reaches the overexcitation condition. Thus, the loadability surface branch  $\mathcal{L}_1$  (with tangent hyperplane  $\mathcal{H}_1$ ) corresponds to the overexcitation limit of generator 1, with generator 2 already at the overexcitation limit.

For a value of  $P_{g2}$  below the intersection point  $p_c$ , the order of generator overexcitation is reversed: generator 1 is now the first to switch to overexcitation limiter, and the

loadability limit is reached when the switching condition of generator 2 is encountered. Therefore, the loadability surface branch  $\mathcal{L}_2$  (with tangent hyperplane  $\mathcal{H}_2$ ) corresponds to the overexcitation limit of generator 2 with generator 1 at the overexcitation limit.

Clearly, the intersection point  $p_c$  corresponds to a simultaneous limiting of both generators, i.e. at this point both switching conditions are satisfied together, so that:

$$h_{11} = h_{12} = h_{21} = h_{22} = 0$$

By taking three of the above conditions, we obtain the loadability surface branches. Specifically for:

$$h_{11} = h_{12} = h_{22} = 0$$

we obtain the switching condition of generator 1, with generator 2 limited, which corresponds to  $\mathcal{L}_1$ . Considering these equations, the singular vector  $w^1$  and the normal vector  $\eta^1$  to  $\mathcal{L}_1$  is found by setting the element of  $w^1$  corresponding to the AVR equation of generator 1 equal to a positive number (e.g. 1) and solving the system (26) for the remaining  $n$  elements.

Note that the elements of  $w^1$  corresponding to  $h_{21}$  and  $h_{22}$  are Lagrange multipliers [13] and, therefore, must be positive for  $\mathcal{L}_1$  to be part of the loadability surface. Similarly for:

$$h_{12} = h_{21} = h_{22} = 0$$

we have the overexcitation condition of generator 2, with generator 1 limited, corresponding to the loadability branch  $\mathcal{L}_2$ . Following the same procedure  $w^2$  is calculated, the sign of its appropriate elements is checked, and the normal vector  $\eta^2$  to  $\mathcal{L}_2$  is determined.

The normal vector  $\eta^1$  indicates how to alleviate the overexcitation of generator 1, while  $\eta^2$  that of generator 2. Obviously, in this case a good direction in order to avoid a loadability limit will be to move along the negative direction of the composition  $\eta$  of the two normal vectors calculated according to (31) and shown in Fig 2.

#### 4. Fold and Hopf bifurcations

As stated before, this paper deals mostly with the loadability surface, which consists partly of static bifurcation points. However, if a *dynamic* bifurcation (typically Hopf) exists prior to a static bifurcation the stability region may be smaller than that corresponding to the loadability limit. To study dynamic bifurcations the full DA model (1)-(2) has to be used, whereas static bifurcations can be analyzed simply from a set of equilibrium conditions (4). This implies a considerably greater computational burden for dynamic bifurcation analysis, as the calculations based on the sparse Jacobian  $D_x f$  can be very fast even for large power systems, whereas the state Jacobian  $A$  defined in

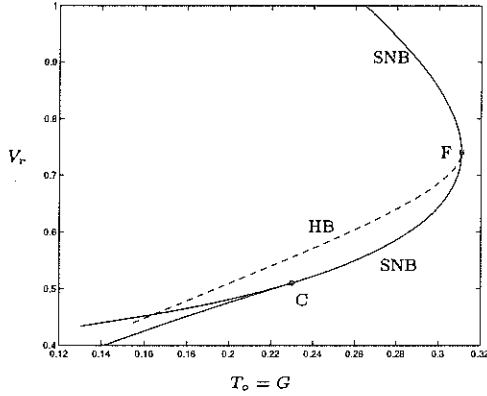


Figure 3: Intersection of Hopf and fold bifurcation surface

(9) is dense. It is still possible, however, as we will propose in this section, to identify the proximity of a Hopf bifurcation branch to the loadability surface, using only the set of sparse equations (4).

We will first investigate through an example the properties of an intersection point of static and Hopf bifurcation surface. Switching-type loadability limits are not considered in this section.

The system studied is taken from [18] and it consists of an infinite bus feeding through a transmission line and an LTC transformer a composite load made up of a constant admittance and an induction motor. The detailed equations and system data can be found in [18]. The LTC is modelled by a continuous differential equation and the induction motor by its first order (rotor motion only) dynamic model. The static load admittance is varied together with the motor torque and thus the independent parameters are:

$$p = [T_o \ V_r]^T$$

where  $T_o$  is the mechanical torque parameter (pu),  $V_r$  is the LTC reference voltage, and  $G = T_o$  is the load conductance (pu).

Fig. 3 shows the fold bifurcation surface  $\Sigma$  in the parameter space as a solid line and the Hopf Bifurcation (HB) surface as a dashed line. The loadability surface in this case coincides with  $\Sigma$ . All points of  $\Sigma$  above point C, except point F, are saddle-node bifurcations. Point C is a co-dimension 3 bifurcation (met in this 2-parameter example due to the particular structure of the system equilibrium equations), whose nature and unfolding have been presented in [18]. This static bifurcation is called “swallowtail” [23], a name justified by the splitting shape of the bifurcation surface below this point.

As the two branches of the swallowtail are crossed, the

number of equilibrium points changes from two to four to zero. The two new equilibria generated when crossing the inner branch of the swallowtail correspond to low primary voltage solutions, whereas the Hopf bifurcation refers to the high voltage solution. Therefore, the apparent crossing of the two curves seen in Fig. 3 has no particular meaning: the high voltage operating point becomes unstable, and at the same time two lower voltage equilibria emerge. The outer branch of the swallowtail contains “double SNB” points, where the two pairs of equilibria disappear together. Due to the low voltages at which it occurs, the swallowtail bifurcation has no practical consequences for the operation of the power system.

Point F, on the other hand, is a bifurcation of much greater importance: a fold bifurcation with a double zero eigenvalue of the state Jacobian  $A$ . As seen in Fig. 3, at this point a Hopf bifurcation surface stems from the loadability surface.

To understand how this comes about, consider that on the HB branch the state Jacobian  $A$  has a real canonical block that can be written as:

$$\begin{bmatrix} 0 & 1 \\ -\omega^2 & 0 \end{bmatrix}$$

Close to the loadability surface the oscillation frequency  $\omega \rightarrow 0$  and thus the Hopf bifurcation becomes a fold with a double zero eigenvalue of  $A$  (point F).

Below point F, the limiting instability for increasing load is the Hopf bifurcation. After the HB the equilibrium becomes unstable and the system operation will be disrupted due to the increasing oscillations before reaching a loadability limit. In this sense, it is critical to identify the HB branch, as this forms the boundary of the stable operating region in parameter space, which, below point F, is smaller than the feasibility region.

The oscillations becoming unstable at the Hopf bifurcation are due to the interaction between two load restoration processes. Specifically, the LTC is restoring load indirectly by restoring the secondary bus voltage and the induction motor by adjusting its slip to meet the load demand for changing terminal voltage. Normally the motor is faster than the LTC, but as the reference voltage drops the motor equilibrium comes closer to the stalling point and thus the motor dynamics become slower and they start to interact with those of the LTC.

It is worth investigating the behavior of the state matrix  $A$  eigenvalues in the neighborhood of point F. A little above point F, by increasing the loading up to the loadability limit (with a constant  $V_r$ ) the eigenvalue movement is as shown in Fig. 4a, i.e. the eigenvalues become real shortly before the SNB and at the limit, when one eigenvalue be-



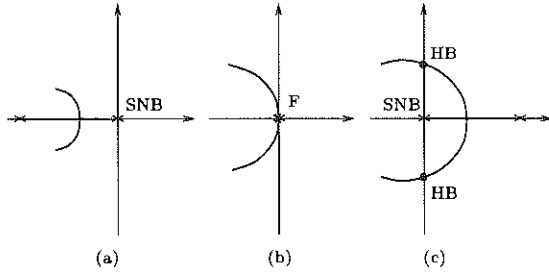


**Figure 4:** Eigenvalue movement up with load: a) above point  $F$ , b) at point  $F$ , c) below point  $F$

comes zero, the second eigenvalue is negative.

For a value of  $V_r$  corresponding exactly to point  $F$ , the eigenvalues become real at the origin, as shown in Fig. 4b, whereas below point  $F$  the eigenvalue movement is as shown in Fig. 4c, i.e. a Hopf bifurcation (HB) is experienced first, and at the SNB point the nonzero eigenvalue is positive.

With the above analysis in mind, the sign of the eigenvalue approaching the origin can identify an instability occurring *before* the loadability limit is reached. The computation of the smallest in magnitude eigenvalue of  $A$  is very simple, since it can be done using the sparse Jacobian  $D_x f$  and applying the inverse iteration method [1]. So, it is very easy to obtain one or more equilibria before a loadability limit is reached, and compute the smallest eigenvalue of  $A$  for each of them.

If the smallest eigenvalues for an equilibrium before the loadability limit is positive, we know that stability has been lost, and thus a complete dynamic analysis of system (1)-(2) is necessary. Also, by approaching the loadability surface from different directions, we may obtain close-by equilibrium points, for which the smallest eigenvalue has different sign (as in Figs 4a and c). If this happens, we have a definite indication that a Hopf bifurcation branch is emanating from the loadability surface from a nearby fold bifurcation point with a double zero eigenvalue of  $A$ .

Note, however, that the above test does not identify all possible instabilities that could have occurred prior to the loadability limit. To do this, a thorough eigenvalue computation of the state Jacobian  $A$  should be undertaken, and this is computationally intensive, as was pointed out earlier.

## 5. Minimum distance problems

### A. Corrective countermeasures vs. security assessment

We have seen in Section 2 that a loadability limit can be defined as a solution to an optimization problem. Going

one step further we discuss in this section the problem of determining the “closest bifurcation” [4, 15], [22]–[24] or the “closest loadability limit” [12] to a particular point in parameter space. There are two variants of this problem corresponding respectively to corrective countermeasures to restore a stable operating point after a severe contingency, and voltage security assessment starting from a feasible operating point:

1. For a post-contingency infeasible point, i.e. a point in parameter space, for which there are no solutions of (4), provide a stable operating point minimizing at the same time the necessary control action (e.g. load shedding).
2. For an actual feasible operating point provide the minimum security margin in terms of load power increase.

Problem 1 has been also called “restoration of solvability” [25, 26]. For this problem the redundancy of the bifurcation condition (10) was proven in [12].

In both of the above variants of the closest loadability problem, the distance to the loadability surface is measured in the literature using either  $L_2$  (Euclidean) or  $L_1$  norm (sum of load changes in MW) [14]. In the case of the first variant the  $L_1$  norm provides a readily acceptable and easily interpretable result, as it gives the minimum total load curtailment in MW necessary to restore a stable operating point.

However, in the second of the above problems, i.e. that of locating the closest loadability limit to an existing operating point, it can be argued that the resulting “shortest distance” with the  $L_1$  norm will in general correspond to an unrealistic stressing pattern of the system, such as doubling the light load of a weak connection with zero load increase on other buses. Although the calculation of such a limit will undoubtedly demonstrate the problem of the weak connection, it is not likely that the system operator would consider a small margin of this type as a serious risk to the system. Thus the “universal” character of the smallest MW distance is seriously challenged.

To avoid this problem we suggest in this paper, as a first step, the normalization of load parameters. Let us assume that the  $m$  parameters  $p$  in (1)–(2) are all load demands. This means that generator setpoints and other control inputs are either constant, or change according to pre-specified rules (e.g. secondary control) to accommodate the load increase. Under this assumption, the parameter space becomes identical to the *load space* [1].

Assume now a normal feasible operating point  $p_o$ . Based on this point the parameter vector  $p$  is replaced by that of

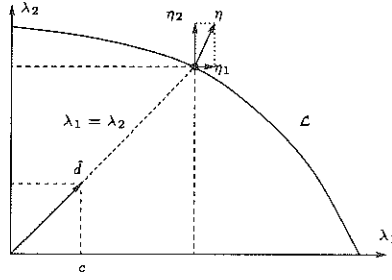


Figure 5: Closest loadability limit by  $L_\infty$  norm

normalized load increase  $\lambda$ , defined as:

$$\lambda_i = \frac{p_i - p_{io}}{p_{io}} \quad (32)$$

Thus  $\lambda_i$  is the percentage increase of load  $p_i$ .

#### B. A practical approach to VSA

The parameter normalization presented above can offer a practical solution to the problem of obtaining the minimum distance to a loadability limit without the need to investigate several directions of stress. To this end we formulate the following problem:

Find the minimum necessary normalized load increase of any load  $\lambda_i$ , in order to reach a loadability limit.

With the above problem definition, the distance to loadability is measured using the  $L_\infty$  norm. The practical consequence is that for any load increase not exceeding the calculated margin percentage, the system is secure. In mathematical terms the closest loadability limit with the specified norm is defined as:

$$\min_d \left\{ \max_{x, \tau} \{ \tau : (20) - (23) : p = p_0(1 + \tau d) \} : \|d\|_\infty = c \right\} \quad (33)$$

where  $c$  is a constant and  $\lambda$  is constrained to increase along direction  $d$ :

$$\lambda = \tau d$$

The geometrical representation of the closest loadability problem (33) is that of inscribing the largest possible square into the feasibility region, as shown in Fig. 5.

The same figure illustrates another important property, which greatly simplifies the search for the closest loadability limit. To this end consider the sensitivity of the loadability margin  $\hat{\tau}$  to the direction of stress  $d$ , given by [1, 27]:

$$\nabla_d \hat{\tau} = -\frac{1}{\eta^T d} \eta \quad (34)$$

or for the  $i$ -th element of  $d$ :

$$\frac{\partial \hat{\tau}}{\partial d_i} = -\frac{\eta_i}{\eta^T d} \quad (35)$$

Let us assume now that at all points of the loadability surface the normal vector  $\eta$  is such that all its elements are positive:

$$\eta_i > 0 \quad \text{for all } i \quad (36)$$

We have implicitly restricted  $d$  to refer to a load increase, thus  $d_i \geq 0$  for all  $i$ , and thus under assumption (36) we get:

$$\eta^T d > 0$$

Therefore, for an increase of any  $d_i$  the loadability margin  $\hat{\tau}$  will decrease according to (35). Clearly then, the minimum margin is obtained along the direction of a uniform load increase, where all  $d_i$  are equal:

$$d_i = c \quad \text{for all } i$$

When the loadability surface contains corner points, assumption (36) must apply to all generalized normal vectors, therefore to all  $\eta^i$ .

We have thus shown that by investigating only one direction of stress, that of a uniform, proportional load demand increase in all buses of the system, the minimum loadability margin (in percentage of the operating point load) is obtained directly.

Now let us investigate further assumption (36). Simply stated we require that all loads contribute to the loadability, or (equivalently) that for a point lying on the loadability surface any load reduction will restore a feasible operating point. This condition is typical in cases of voltage stability constrained systems, and in this sense (36) is a reasonable assumption to make. In the following section we will see a counterexample, which however corresponds to a loadability limit due partly to angle stability.

We now present a general algorithm to obtain and analyze the closest loadability limit (33) under assumption (36):

1. Simulate a uniform load increase of all system loads. This can be easily done with QSS simulation [1].
2. During the simulation, monitor the point where the trajectory reaches the loadability surface. This can be done by calculating a long-term sensitivity index, whose change of sign through infinity indicates when the loadability limit is reached [14].
3. When a loadability limit is reached, determine if it is due to a smooth load increase, or to switching of one or more limiting devices (LTC action is considered approximately smooth in this respect).

**Table 2:** Two-load system data (pu 100 MVA basis)

| $X_{15} = X_{24}$  | $X_{34}$           | $X_{45}$ | $r$    |
|--------------------|--------------------|----------|--------|
| 0.032              | 0.005625           | 0.4      | 1.04   |
| $P_{1o} = P_{g1o}$ | $P_{2o} = P_{g2o}$ | $B$      | $Q$    |
| 1.0                | 1.0                | 0.25     | $0.5P$ |

4. Depending on how the loadability limit was brought about calculate the singular vector  $w$ :

- If the limit is due to a smooth load increase, using the inverse iteration method to compute the smallest eigenvalue of the square Jacobian  $D_x \psi$  and its associated left eigenvector.
- If the limit is due to the switching of one or more devices, by solving the rectangular system of equations (26) separately for each switching condition encountered. A check on the signs of the elements of  $w$  corresponding to inequalities is performed in this case to verify that the switching condition is indeed part of the loadability surface.

5. Based on the computed singular vector(s)  $w$  calculate the normal vector(s)  $\eta$  to the loadability surface (or to each of its branches).

6. Suggest and evaluate appropriate countermeasures, based on the normal vector, or the generalized normal vector calculated as above.

## 6. Test cases

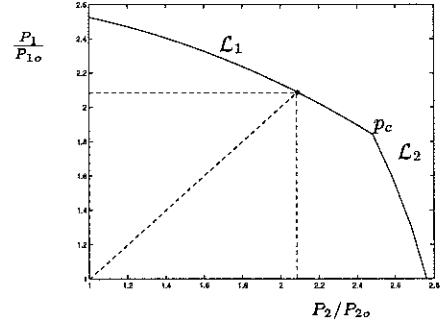
### A. Two load test system

In this section we analyze the two generator system shown in Fig. 1 for various loading patterns, in order to illustrate the method developed in the previous section and the implications of a violation of assumption (36), on which it is based. The generator data are the same as in Table 1.

First we investigate a case of symmetrical initial loading of the system, where each generator is serving its local load. The network data and initial operating condition for the symmetrical loading case are shown in Table 2. Note, that the line 4-5 is now longer, so that essentially we have a two area system. Both loads are constant power factor with  $Q = P/2$  and are restoring to constant real and reactive power after a disturbance. Both generators share the load changes with an equal participation factor of 50%. Therefore, the active generation of both generators is a function of the load increase and the only independent parameters are the active load demands:

$$p = [P_1 \ P_2]^T$$

The loadability surface with the initial loading of Table 2 is shown in Fig. 6. Clearly in this case the normal vector

**Figure 6:** Closest loadability limit (symmetrical initial loading)**Table 3:** Operating point with area 2 exporting

| $X_{15} = X_{24}$ | $X_{34}$  | $X_{45}$ | $r$       |
|-------------------|-----------|----------|-----------|
| 0.032             | 0.005625  | 1.0      | 1.04      |
| $P_{1o}$          | $P_{g1o}$ | $P_{2o}$ | $P_{g2o}$ |
| 1.0               | 0.5       | 0.5      | 1.0       |

at all points of the loadability surface (including the generalized normal vector at the corner point  $p_c$ ) have only positive elements, in other words they satisfy assumption (36). Therefore, the direction to the closest loadability limit (33), is given by the uniform load increase shown with a dashed line. The minimum loadability margin for this lightly loaded operating point is close to a 110% load increase.

Let us now investigate a different initial loading pattern, where generator 2 is exporting half of its active power to the load  $P_1$  near generator 1. The initial operating condition is shown in Table 3. To make the separation between the two areas more pronounced, we have increased further the reactance of line 4-5. The remaining data are as in Table 2.

In this case the loadability surface in normalized load space is shown in Fig. 7. It consists of two branches:

- $\mathcal{L}_1$  corresponds to a switching loadability limit met when generator 1 becomes overexcited, while generator 2 is still under voltage regulation.
- Similarly,  $\mathcal{L}_2$  corresponds to the switching loadability limit due to generator 2 overexcitation, with generator 1 under voltage regulation

The corner point, where the two branches meet corresponds to a simultaneous OEL switching of both generators.

As clearly seen in Fig. 7, in this case we have a violation of assumption (36), since for relatively low values of  $P_2/P_{2o}$  (roughly less than 3), the slope of the loadability branch  $\mathcal{L}_1$  changes, so that the element of its normal vector  $\eta$  corresponding to load  $P_2$  becomes *negative*. As a consequence,

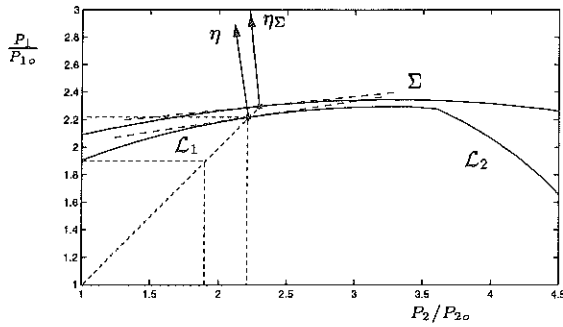


Figure 7: Loadability surface with area 2 exporting

Table 4: Generator angle difference at the loadability limit

|                       |       |       |       |       |
|-----------------------|-------|-------|-------|-------|
| $P_2/P_{2o}$          | 3.0   | 2.8   | 2.6   | 2.4   |
| $\delta_2 - \delta_1$ | 55.9° | 60.1° | 64.3° | 68.4° |
| $P_2/P_{2o}$          | 2.2   | 2.0   | 1.8   | 1.6   |
| $\delta_2 - \delta_1$ | 72.5° | 76.5° | 80.6° | 84.6° |
| $P_2/P_{2o}$          | 1.4   | 1.2   | 1.0   |       |
| $\delta_2 - \delta_1$ | 88.6° | 92.6° | 96.6° |       |

the minimum percentage of load increase to meet a loadability limit is less than 120% (as predicted by the uniform load increase shown by the dashed line). In fact, by a 90% increase of only load  $P_1$  a loadability limit is obtained.

Let us examine now the implications of violating the positive normal vector assumption (36). Consider, for instance, a load increase of only  $P_1$  up to the point where generator 1 becomes overexcited and a loadability limit is reached. An increase of load  $P_2$  at this point will be partly accommodated by the increase of generation in area 1, thus reducing the heavy import from area 2. This will alleviate the overexcitation of generator 1 and the loadability limit will be avoided.

It can be argued at this point that this loadability limit is closer to an *angle* instability type of problem. To illustrate this we show in Table 4 the angle difference  $\delta_2 - \delta_1$  between the two machine rotors at the loadability limit. As seen in the Table, in the part of the loadability surface  $\mathcal{L}_1$  where  $\eta_2$  (the normal vector element corresponding to  $P_2$ ) is negative, the angle difference exceeds 60°. In fact, for low values of  $P_2$ ,  $\delta_2 - \delta_1$  goes even above 90°. Note that this is the angle difference even *before* the activation of the overexcitation limiter, i.e. while the generator is still under AVR control.

Even though the distinction between angle and voltage stability is somewhat ambiguous at this stage, it is reasonable to assume that with the large angle differences of Table 4, a standard transient security assessment (not undertaken in this paper) would reveal that the system is transient stability constrained in this region of the parameter space.

Of course, the angle stability problem becomes much more prominent after the activation of the OEL, leading eventually to a loss of synchronism.

We can conclude, therefore, that in this example the system that violates the positive normal vector assumption (36) is one constrained (at least partly) by angle stability problems.

In Fig. 7 we show also the bifurcation surface  $\Sigma$  with generator 1 under OEL control. Note that  $\Sigma$  lies outside the feasibility region, as the loadability limit encountered is of the switching type. We also show the normal vector to the bifurcation surface  $\eta_\Sigma$  to compare with the normal vector  $\eta$  to the actual loadability surface  $\mathcal{L}_1$ . The comparison shows that the two directions are slightly different, meaning that the countermeasures taken based on the left eigenvector of the singular Jacobian at  $\Sigma$  will differ, but only slightly in this case, from those calculated with the normal vector to the actual loadability surface.

#### B. Hellenic Power System

We will now give an example of the application of the method described in Section 5B to an existing power system, namely the Hellenic interconnected network. The system consists of 926 buses, 506 transformers, 635 lines, 66 generators and one external interconnection. The long-term dynamics of this system are those of the LTCs controlling the voltage of the distribution side of bulk power delivery transformers.

The system is simulated using WPSTAB, a voltage stability analysis package developed at the Electrical Energy Systems Lab of NTUA. The long-term simulation is carried out using the quasi-steady-state approach, while the loadability conditions are monitored using a long-term sensitivity index [28].

We impose to the initial operating point a uniform load increase until a loadability limit is reached. The loadability margin calculated in this way is 32%. The loadability limit obtained is due to the simultaneous OEL switching of four generators. After the switching, the smallest eigenvalue of the state Jacobian is calculated to be +0.16. The left eigenvector corresponding to this eigenvalue is used to calculate an approximation of the normal vector to the bifurcation surface  $\eta_\Sigma$  in the parameter space of LTC reference voltages. The prominent elements of this normal vector are shown in Table 5, together with those of the normal vectors  $\eta^i, i = 1, \dots, 4$  corresponding to the four switching conditions.

Normal vectors in the load space (P and Q load demands at each bus) are also calculated by the program and can be used for direct load shedding, whereas the vectors in

Table 5: Normal vectors at loadability limit

| No. | Bus  | $\eta^1$ | $\eta^2$ | $\eta^3$ | $\eta^4$ | $\eta$ | $\eta_\Sigma$ |
|-----|------|----------|----------|----------|----------|--------|---------------|
| 1   | AITW | 1.00     | 1.00     | 0.86     | 0.67     | 1.00   | 1.00          |
| 2   | YUC2 | 0.50     | 0.49     | 1.00     | 1.00     | 0.76   | 0.97          |
| 3   | ELE3 | 0.52     | 0.52     | 0.90     | 0.88     | 0.73   | 0.92          |
| 4   | AIGA | 0.42     | 0.41     | 0.82     | 0.82     | 0.63   | 0.80          |
| 5   | AIGI | 0.69     | 0.69     | 0.64     | 0.52     | 0.71   | 0.76          |
| 6   | ELE1 | 0.41     | 0.41     | 0.69     | 0.67     | 0.57   | 0.72          |
| 7   | YUC6 | 0.26     | 0.27     | 0.65     | 0.67     | 0.46   | 0.67          |
| 8   | MGL3 | 0.52     | 0.51     | 0.44     | 0.35     | 0.51   | 0.63          |
| 9   | ALUM | 0.32     | 0.32     | 0.68     | 0.69     | 0.51   | 0.63          |
| 10  | PAT3 | 0.55     | 0.55     | 0.46     | 0.36     | 0.55   | 0.56          |
| 11  | BZPA | 0.49     | 0.49     | 0.41     | 0.32     | 0.49   | 0.51          |
| 12  | TRIC | 0.55     | 0.55     | 0.49     | 0.39     | 0.56   | 0.56          |
| 13  | SERE | 0.37     | 0.36     | 0.79     | 0.80     | 0.59   | 0.56          |

Table 5 can be used for indirect load reduction by suitably adjusting the reference voltage of certain LTCs.

The first two normal vectors  $\eta^1, \eta^2$  of Table 5 refer to the OEL switching of two generators belonging to the same power plant in the Southern peninsula of Peloponnese. As seen in the Table, these two vectors are almost collinear, i.e. the corresponding loadability branches are almost tangent. Vectors  $\eta^3$  and  $\eta^4$  refer to the switching conditions of two generators located at different power plants near the load center of Athens. These vectors are close to each other, but are definitely at an angle.

The actual computation of preventive countermeasures is beyond the scope of this paper. However, it is interesting to compare the normal vector to  $\Sigma$  and the generalized normal vector at the corner point of  $\mathcal{L}$ , both shown in Table 5.

The generalized normal vector  $\eta$ , calculated according to (31), has been subsequently normalized similarly to the other vectors, so that its largest element is equal to 1. Comparing the normalized  $\eta$  to  $\eta_\Sigma$ , it is clear that there are similarities (e.g. largest element at the same bns), as well as differences. The most important difference is that the elements of  $\eta_\Sigma$  are considerably larger for buses 2, 3, 4, 6, 7, all of which are located in large substations feeding the Athens area. As a consequence, if  $\eta_\Sigma$  is used for calculating countermeasures, the load reduction in the Athens region will be significantly larger, than that obtained by using the generalized normal vector  $\eta$ .

## 7. Conclusions

In this paper the properties of the loadability surface of a power system at intersection points of various loadability and bifurcation branches were investigated. In particular, it was found that the loadability surface contains corner points where the loadability limit is due to several switching actions occurring together. At such points a gener-

alized normal vector to the loadability surface was introduced and its computation process was outlined.

The properties of a fold bifurcation with a double zero eigenvalue of the state Jacobian were also analyzed in the paper through an example. It was found that this bifurcation occurs at the intersection of the loadability and the Hopf bifurcation surface, where the nature of the limiting instability changes. The proximity to such a point can be identified through a change in the sign of the smallest eigenvalue of the state Jacobian, computed as the loadability surface is approached.

Also, in the paper a method to compute directly the minimal percentage of load increase in order to reach a loadability limit, subject to a reasonable assumption, was suggested. An example showed that when the assumption made is violated, the system loading may be restricted by angle stability considerations. Further research, however, is required to clarify this condition.

Finally, an algorithmic approach to compute for the closest loadability limit the normal vector (or a generalized normal vector) to the loadability surface was developed. This normal vector can subsequently be used for preventive control. The method was applied to a practical power system with 926 buses and the normal vector to the loadability surface, calculated according to the analysis of this paper, was compared to that obtained by eigenvalue analysis.

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# Strong Resonance Effects in Normal Form Analysis and Subsynchronous Resonance

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**Abstract:** Power system normal form analysis has developed coefficients and indices in modal coordinates to quantify nonlinear model interactions. The coefficients can become very large near a strong, nondiagonalizable resonance occurring in the power system linearization. Moreover, the changes in the coefficients when the power system equations are expressed in different coordinates or units show that the coefficients are not intrinsic. On a different topic, the paper suggests an explanation for the modal interaction that causes the subsynchronous resonance instability in power systems. The modal interaction is associated with a pair of strong resonances which arise as a perturbation of a weak resonance of complex eigenvalues. This idea is supported using results from the IEEE first benchmark subsynchronous resonance model and perturbation theory.

## 1 Introduction

Power systems are increasingly operated closer to their limits. Advances in communications, control, computing, signal processing and power electronics are enabling a more highly controlled power system. Stressed and more highly controlled power systems generally exhibit more nonlinear effects and dynamic modal interactions. To achieve a high performance power system that is controlled to reliably operate near its limits, dynamic modal interactions must be better understood so that they can be mitigated. This paper examines the effects and implications of strong modal resonance in power system normal form analysis and subsynchronous resonance. The effect of coordinate changes on normal form coefficients and indices is also studied.

### 1.1 Strong and weak resonance

The power system linearization and its modes vary as power system parameters change. In particular it is possible for two eigenvalues of the linearization to coincide and this is called a resonance, or a first order resonance. If the linearization is not diagonalizable at the resonance, the resonance is called a *strong* resonance [12]. Otherwise, if the linearization is diagonalizable at the resonance, the resonance is called a *weak* resonance. The resonance can occur with two eigenvalues coinciding on the real axis or with two complex conjugate pairs of eigenvalues coinciding in both

frequency and damping.

At a strong resonance, the two eigenvalues move together, briefly coincide and then split apart at right angles to the original direction of movement. Strong resonance of complex eigenvalues does not occur generically in systems with a single real parameter. Thus in practice the power system will not experience an exact strong resonance, but can pass close to such a resonance and the qualitative effects are similar: the eigenvalues move close together, quickly change direction by approximately a right angle and then move apart. The strong resonance and its implications for stability are known in mechanics [12, 13].

Dobson et al. [4] shows how passing near a complex strong resonance can cause oscillatory instability in power system models. The reader is referred to [4] for further explanation and analysis of strong resonance and a detailed review of previous indications that strong resonance may occur in interarea power system oscillations. [4] also shows that proximity to strong resonance is expected to occur generically in power systems and studies the effects of passing close to a single strong resonance. However, weak resonance, while generally much less generic than strong resonance, is also possible in power system models with special structure. Moreover, [4] raises the question of whether perturbations of weak resonance also occur in power systems.

### 1.2 Power system normal form analysis

Over the last decade normal form analysis has been developed to investigate and quantify nonlinear interactions between power system modes [9, 14, 15, 17]. Applications include control system design [9, 7] and predicting interarea separation [14, 15]. The method starts with power system differential equations which are expanded in a Taylor series about a stable equilibrium. The differential equations are then transformed so that the linearization is diagonalized and the equations are written in modal coordinates. The coefficients of the quadratic terms in the modal coordinates are the quantities  $C_{jk}^i$ , where  $i, j$  and  $k$  are indices ranging from 1 to  $n$ , the number of state variables. Then the equations are nonlinearly transformed to be linear up to second order. The sizes of second order terms  $h2_{jk}^i$  in the nonlinear transformation are used to quantify nonlinear interactions between the modes. The  $h2_{jk}^i$  are calculated from the  $C_{jk}^i$

using

$$h2_{jk}^i = \frac{C_{jk}^i}{\lambda_j + \lambda_k - \lambda_i} \quad (1)$$

where  $\lambda_1, \lambda_2, \dots, \lambda_n$  are the eigenvalues of the power system linearization.

A *second order resonance* occurs when two eigenvalues sum to equal a third eigenvalue. The formula (1) shows that the  $h2_{jk}^i$  become large near a second order resonance in which  $\lambda_j + \lambda_k - \lambda_i$  vanishes. Nonlinear mode couplings become large near second order resonance. Note that, in contrast, the strong and weak resonances discussed above are first order resonances which occur within the system linearization.

### 1.3 Subsynchronous resonance

In regions with long transmission lines, such as the western United States, it can be desirable to compensate the lines with series capacitors to increase the maximum power transfer through the lines. However, series capacitors can introduce resonance problems. Subsynchronous resonance is an electromechanical power system instability in which electrical modes of transmission lines compensated with series capacitors interact with torsional modes of generator shafts [5, 1, 11]. This instability can break generator shafts and must be studied and prevented when series compensation is used.

### 1.4 Objectives and organization of paper

After reviewing the power system normal form analysis procedure in section 2, the subsequent sections have the following objectives:

- Section 3 examines normal form analysis near strong resonance. Some of the coefficients used to quantify nonlinear interactions become very large near strong resonance.
- Section 4 studies how coefficients used to quantify nonlinear interactions in normal form analysis change when different coordinates or units are used in the power system model.
- Section 5 explores the anatomy of the subsynchronous resonance instability using concepts of strong and weak resonance. Perturbations of a weak resonance of complex eigenvalues are analyzed and illustrated. The results suggest that subsynchronous resonance is caused by a pair of strong resonances which are a perturbation of a weak resonance.

Sections 3, 4 and 5 may be read independently. Section 6 summarizes the conclusions.

## 2 Normal form analysis procedure

This section reviews the mechanics of the normal form calculation of Lin, Vittal, Kliemann, and Fouad [9] and Starrett and Fouad [14]. We follow much of the notation of [9] for convenience.

The power system dynamics are linearized about a stable equilibrium and expanded in a Taylor series to obtain

$$\dot{x}_i = \sum_{j=1}^n A_{ij} x_j + \frac{1}{2} \sum_{j=1}^n \sum_{k=1}^n H_{jk}^i x_j x_k + h.o.t. \quad (2)$$

where  $X = (x_1, x_2, \dots, x_n)^t$  is the system state defined relative to the stable equilibrium,  $A$  is the Jacobian matrix and the Hessian  $H$  defines the coefficients of quadratic terms. When transients are considered, the initial condition is written as  $X_0 = (x_{10}, x_{20}, \dots, x_{n0})^t$ .

The Jacobian matrix  $A$  is assumed to be diagonalizable. Equation (2) is transformed to modal coordinates  $Y = (y_1, y_2, \dots, y_n)^t$  which diagonalize the matrix  $A$ . In particular,  $U$  is defined to be a matrix whose columns are the right eigenvectors of  $A$ . An important detail [9] is that the right eigenvectors (columns of  $U$ ) are normalized so that they have length 1. (An assumption about the normalization of  $U$  is needed to unambiguously define the  $C_{jk}^i$  below.) Then

$$X = UY \quad (3)$$

is a transformation to modal  $Y$  coordinates. Transforming (2) to the modal  $Y$  coordinates yields

$$\dot{y}_i = \lambda_i y_i + \sum_{j=1}^n \sum_{k=1}^n C_{jk}^i y_j y_k + h.o.t. \quad (4)$$

where  $\lambda_1, \lambda_2, \dots, \lambda_n$  are the eigenvalues of  $A$ .

The  $C_{jk}^i$  are the quadratic coefficients in the  $Y$  coordinates and are given by

$$C_{jk}^i = \frac{1}{2} \sum_{r=1}^n \sum_{\ell=1}^n \sum_{m=1}^n (U^{-1})_{ir} H_{\ell m}^r U_{\ell j} U_{m k} \quad (5)$$

The  $h2$  coefficients are then defined by (1).

Normal form theory states that the local nonlinear transformation from  $Y$  to  $Z$  variables given by

$$y_i = z_i + \sum_{j=1}^n \sum_{k=1}^n h2_{jk}^i z_j z_k \quad (6)$$

linearizes the differential equations to second order so that

$$\dot{z}_i = \lambda_i z_i + \text{third order terms} \quad (7)$$

An initial condition  $X_0$  for a transient becomes  $Y_0 = U^{-1}X_0$  in the  $Y$  coordinates and  $Z_0$  in the  $Z$  coordinates



where  $Z_0 = (z_{10}, z_{20}, \dots, z_{n0})^t$  satisfies

$$y_{i0} = z_{i0} + \sum_{j=1}^n \sum_{k=1}^n h_{2jk}^i z_{j0} z_{k0} \quad (8)$$

Several measures of the nonlinearity in  $Y$  coordinates were proposed in [15] based on the  $h2$  coefficients and the initial condition of a transient. An interaction coefficient is defined as

$$h_{2jk}^i z_{j0} z_{k0} \quad (9)$$

to quantify the effect of second order terms on the transient solution. The nonlinear interaction index  $I1$  for mode  $i$  is defined as

$$I1(i) = |y_{i0} - z_{i0} + h_{2j^*k^*}^i z_{j^*0} z_{k^*0}| \quad (10)$$

where the choice of  $j = j^*$  and  $k = k^*$  maximizes the interaction coefficient size  $|h_{2jk}^i z_{j0} z_{k0}|$ . The nonlinearity index  $I2$  for mode  $i$  is defined as

$$I2(i) = \frac{h_{2j^*k^*}^i z_{j^*0} z_{k^*0}}{z_{i0}} \quad (11)$$

We do not address the generalized participation factor analysis of [14, 18] in this paper.

### 3 Normal form analysis near strong resonance

In the context of the normal form analysis, strong resonance is a first order resonance occurring within the power system linearization. We present examples showing that the coefficients and indices  $C_{jk}^i$ ,  $h_{2jk}^i$ ,  $h_{2jk}^i z_{j0} z_{k0}$ ,  $I1$ ,  $I2$  become arbitrarily large near strong resonance despite the very small amounts of nonlinearity in the system expressed in its original coordinates.

#### 3.1 Real strong resonance example

This subsection gives a two dimensional example in which the system is near to a strong resonance of two eigenvalues on the real axis. (A version of this example appeared in [3, appendix B] with correct conclusions but an incorrect constant factor for the  $U$  matrix.) Consider

$$\begin{aligned} \dot{x}_1 &= -x_1 + x_2 \\ \dot{x}_2 &= \mu x_1 - x_2 + \frac{1}{2} \epsilon x_1^2 \end{aligned} \quad (12)$$

so that  $A = \begin{pmatrix} -1 & 1 \\ \mu & -1 \end{pmatrix}$  and all  $H_{jk}^i = 0$  except that  $H_{11}^2 = \epsilon$ .  $\epsilon$  and  $\mu$  are small real constants. The eigenvalues of  $A$  are  $-1 \pm \sqrt{\mu}$  and these coincide in a strong resonance at  $-1$  when  $\mu = 0$ . We assume  $\mu \neq 0$  in order to diagonalize  $A$  and compute

$$U = \frac{1}{\sqrt{1+\mu}} \begin{pmatrix} 1 & 1 \\ \sqrt{\mu} & -\sqrt{\mu} \end{pmatrix} \quad (13)$$

$$U^{-1} = \frac{\sqrt{1+\mu}}{2} \begin{pmatrix} 1 & \frac{1}{\sqrt{\mu}} \\ 1 & \frac{-1}{\sqrt{\mu}} \end{pmatrix} \quad (14)$$

Then (12) in  $Y$  coordinates becomes

$$\dot{y}_1 = (-1 + \sqrt{\mu})y_1 + \frac{\epsilon}{4\sqrt{\mu}\sqrt{1+\mu}}(y_1^2 + 2y_1y_2 + y_2^2)$$

$$\dot{y}_2 = (-1 - \sqrt{\mu})y_2 - \frac{\epsilon}{4\sqrt{\mu}\sqrt{1+\mu}}(y_1^2 + 2y_1y_2 + y_2^2)$$

and

$$C_{jk}^i = \frac{\epsilon(-1)^{i+1}}{4\sqrt{\mu}\sqrt{1+\mu}} \quad (15)$$

$$h_{21}^1 = \frac{\epsilon}{4\sqrt{\mu}\sqrt{1+\mu}} \begin{pmatrix} \frac{1}{-1+\sqrt{\mu}} & \frac{1}{-1-\sqrt{\mu}} \\ \frac{1}{-1-\sqrt{\mu}} & \frac{1}{-1+\sqrt{\mu}} \end{pmatrix} \quad (16)$$

$$h_{22}^2 = \frac{\epsilon}{4\sqrt{\mu}\sqrt{1+\mu}} \begin{pmatrix} \frac{-1}{-1+\sqrt{\mu}} & \frac{-1}{-1-\sqrt{\mu}} \\ \frac{-1}{-1-\sqrt{\mu}} & \frac{-1}{-1+\sqrt{\mu}} \end{pmatrix} \quad (17)$$

Note the factor  $\frac{\epsilon}{\sqrt{\mu}}$  in (15) and (16,17).

The appendix considers the behavior of the initial condition  $Z_0$  near strong resonance and proves that one can find values of  $\mu$  tending to zero such that one or more of the interaction coefficients  $h_{2jk}^i z_{j0} z_{k0}$  becomes arbitrarily large. Indices  $I1$  and  $I2$  become arbitrarily large in the same way.

#### 3.2 Complex strong resonance example

This subsection gives a four dimensional example in which the system is near to a strong resonance of two complex conjugate pairs of eigenvalues.

$$\begin{pmatrix} \dot{x}_1 \\ \dot{x}_2 \\ \dot{x}_3 \\ \dot{x}_4 \end{pmatrix} = \begin{pmatrix} -1 & 1 & 1 & 0 \\ \mu & -1 & 0 & 1 \\ -1 & 0 & -1 & 1 \\ 0 & -1 & \mu & -1 \end{pmatrix} \begin{pmatrix} x_1 \\ x_2 \\ x_3 \\ x_4 \end{pmatrix} + \begin{pmatrix} 0 \\ \frac{1}{2} \epsilon x_1^2 \\ 0 \\ 0 \end{pmatrix} \quad (18)$$

All  $H_{jk}^i = 0$  except that  $H_{11}^2 = \epsilon$ .  $\epsilon$  and  $\mu$  are small real constants. The eigenvalues of the matrix in (18) are  $\lambda_1 = -1 + i + \sqrt{\mu}$ ,  $\lambda_2 = -1 + i - \sqrt{\mu}$  and their complex conjugates  $\lambda_1^*$ ,  $\lambda_2^*$ . The eigenvalues  $\lambda_1$  and  $\lambda_2$  coincide in a strong resonance at  $-1 + i$  when  $\mu = 0$ . ( $\lambda_1^*$  and  $\lambda_2^*$  mirror this behavior below the real line by coinciding in a strong resonance at  $-1 - i$  when  $\mu = 0$ .) We assume  $\mu \neq 0$  in order to diagonalize the matrix in (18) and compute

$$U = \frac{1}{\sqrt{2}\sqrt{1+\mu}} \begin{pmatrix} 1 & 1 & 1 & 1 \\ \sqrt{\mu} & -\sqrt{\mu} & \sqrt{\mu} & -\sqrt{\mu} \\ i & i & -i & -i \\ i\sqrt{\mu} & -i\sqrt{\mu} & -i\sqrt{\mu} & i\sqrt{\mu} \end{pmatrix}$$

$$U^{-1} = \frac{\sqrt{1+\mu}}{2\sqrt{2}} \begin{pmatrix} 1 & \frac{1}{\sqrt{\mu}} & -i & \frac{-i}{\sqrt{\mu}} \\ 1 & \frac{1}{\sqrt{\mu}} & -i & \frac{i}{\sqrt{\mu}} \\ 1 & \frac{1}{\sqrt{\mu}} & i & \frac{i}{\sqrt{\mu}} \\ 1 & \frac{1}{\sqrt{\mu}} & i & \frac{-i}{\sqrt{\mu}} \end{pmatrix}$$

Then (18) in  $Y$  coordinates becomes

$$\begin{pmatrix} \dot{y}_1 \\ \dot{y}_2 \\ \dot{y}_3 \\ \dot{y}_4 \end{pmatrix} = \begin{pmatrix} \lambda_1 y_1 \\ \lambda_2 y_2 \\ \lambda_1^* y_3 \\ \lambda_2^* y_4 \end{pmatrix} + \frac{\epsilon(y_1 + y_2 + y_3 + y_4)^2}{8\sqrt{2}\sqrt{\mu}\sqrt{1+\mu}} \begin{pmatrix} 1 \\ -1 \\ 1 \\ -1 \end{pmatrix} \quad (19)$$

and

$$C_{jk}^i = \frac{\epsilon(-1)^{i+1}}{8\sqrt{2}\sqrt{\mu}\sqrt{1+\mu}} \quad (20)$$

$$h2_{jk}^i = \frac{\epsilon(-1)^{i+1}}{8(\lambda_j + \lambda_k - \lambda_i)\sqrt{2}\sqrt{\mu}\sqrt{1+\mu}} \quad (21)$$

Note the factor  $\frac{\epsilon}{\sqrt{\mu}}$  in (20) and (21).

Similarly to the real resonance case in the appendix, one can find values of  $\mu$  tending to zero such that an interaction coefficient  $h2_{jk}^i z_{j0} z_{k0}$  and the indices  $I1$  and  $I2$  become arbitrarily large.

### 3.3 Discussion

Both examples show that near strong resonance, the  $C_{jk}^i$  and  $h2_{jk}^i$  coefficients scale as  $\frac{\epsilon}{\sqrt{\mu}}$ . Here  $\epsilon$  controls the amount of nonlinearity in the original coordinates ( $\epsilon = 0$  gives no nonlinearity) and  $\mu$  controls the proximity to strong resonance ( $\mu = 0$  gives a strong resonance). No matter how small  $\epsilon$  is, one can choose a smaller  $\mu$  so that the coefficients  $C_{jk}^i$  and  $h2_{jk}^i$  have very large magnitudes. Indeed  $C_{jk}^i$  and  $h2_{jk}^i$  tend to infinity as the strong resonance is approached. Moreover, for both examples, an interaction coefficient  $h2_{jk}^i z_{j0} z_{k0}$  and the indices  $I1$  and  $I2$  become arbitrarily large for values of  $\mu$  which tend to zero.

That is, no matter how small is the quadratic nonlinearity in the equations in the original  $X$  coordinates, one can, by moving close to the strong resonance, make the coefficients and indices  $C_{jk}^i$ ,  $h2_{jk}^i$ ,  $h2_{jk}^i z_{j0} z_{k0}$ ,  $I1$ ,  $I2$  arbitrarily large. Therefore caution is needed in interpreting these coefficients and indices near strong resonance. Large values of these coefficients and indices correctly reflect the high nonlinearity of the system in the modal  $Y$  coordinates, but do not necessarily imply that the system has significant nonlinearity in the original  $X$  coordinates. The coordinate change to modal  $Y$  coordinates requires increasing distortion as strong resonance is approached and this distortion can greatly amplify nonlinearities. These results show that, as well as quantifying second order nonlinear modal interactions, normal form analysis also detects strong resonance effects (first order linear modal interactions) which are not necessarily related to significant system nonlinearity in the original  $X$  coordinates.

The occurrence of strong resonance also has some effect on the procedure to determine second order resonance condi-

tions in [17, section IVB]. This procedure requires eigenvalues to vary smoothly enough with respect to parameters so that they can be approximated by a quadratic polynomial in the parameters. However, this is not possible at strong resonance, where eigenvalues are not differentiable with respect to parameters. At strong resonance the eigenvalues vary as fractional powers of a parameter despite the smoothness or analyticity of the power system equations. (Note the dependence of the eigenvalues on  $\sqrt{\mu}$  in subsections 3.1 and 3.2.) One also expects accuracy problems when trying to approximate eigenvalue movement with quadratic polynomials near a strong resonance.

### 4 Dependence of coefficients and indices on coordinate systems and units

The coefficients and indices  $C_{jk}^i$ ,  $h2_{jk}^i$ ,  $h2_{jk}^i z_{j0} z_{k0}$ ,  $I1$ ,  $I2$  depend on the coordinate system used to express the power system differential equations. In particular, the values of these coefficients and indices vary if the state variables are expressed in different units.

The essence of the problem can be seen in a simple example. Consider the following one dimensional differential equation in which the state variable  $x$  is measured in MW.

$$\dot{x} = -x + x^2 \quad (22)$$

If we change the state variable to be  $\bar{x}$  where  $\bar{x}$  is measured in kW, then

$$\bar{x} = 1000 x \quad (23)$$

and (22) becomes

$$\dot{\bar{x}} = -\bar{x} + 0.001\bar{x}^2 \quad (24)$$

For (22) it is apparent that  $C_{11}^1 = 1$ .  $C_{11}^1$  is intended to quantify the nonlinear interaction of mode 1 (the only mode) of system (22) with itself. But in (24), which represents the same physical system in different units, we have  $\bar{C}_{11}^1 = 0.001$ . It is clear that the size of the nonlinearity as measured by the  $C_{11}^1$  coefficient varies according to the units chosen to express the differential equation. Note that both  $x$  and  $\bar{x}$  are modal coordinates; there is no unique choice of modal coordinates.

There are also changes in  $h2_{11}^1$  and the interaction coefficient  $h2_{11}^1 z_0^2$  when the units are changed. For (22),  $h2_{11}^1 = -1$ , whereas for (24),  $\bar{h}2_{11}^1 = -0.001$ . For (22), solving (8) and (3) gives  $z_0 = \frac{1}{2} - \sqrt{\frac{1}{4} - x_0}$  and

$$h2_{11}^1 z_0^2 = x_0 - \frac{1}{2} + \sqrt{\frac{1}{4} - x_0} \quad (25)$$

whereas for (24),  $\bar{z}_0 = 500 - \sqrt{250000 - 1000\bar{x}_0}$  and

$$\bar{h}2_{11}^1 \bar{z}_0^2 = \bar{x}_0 - 500 + \sqrt{250000 - 1000\bar{x}_0} = 1000 h2_{11}^1 z_0^2 \quad (26)$$

#### 4.1 Linear transformation of coordinates

We transform the differential equations from the original  $X$  coordinates to  $\bar{X}$  coordinates and then compute the coefficients and indices  $\bar{C}_{jk}^i$ ,  $\bar{h}_{jk}^i$ ,  $\bar{h}_{jk}^i z_{j0} z_{k0}$ ,  $\bar{I}1$ ,  $\bar{I}2$ . In this way we find out how these coefficients and indices depend on the coordinate system from which they are computed.

Suppose that the  $X$  and  $\bar{X}$  coordinates are related by an invertible linear transformation  $T$  according to

$$X = T\bar{X} \quad (27)$$

Then the differential equations in  $\bar{X}$  coordinates are

$$\dot{\bar{x}}_i = \sum_{j=1}^n \bar{A}_{ij} \bar{x}_j + \frac{1}{2} \sum_{j=1}^n \sum_{k=1}^n \bar{H}_{jk}^i \bar{x}_j \bar{x}_k + h.o.t.$$

where

$$\bar{A} = T^{-1}AT \quad (28)$$

$$\bar{H}_{jk}^i = \sum_{r=1}^n \sum_{\ell=1}^n \sum_{m=1}^n (T^{-1})_{ir} H_{\ell m}^r T_{\ell j} T_{mk} \quad (29)$$

Right eigenvectors in the  $\bar{X}$  coordinates are given by the columns of  $T^{-1}U$ , but in general these columns will not be of length 1. Therefore we define

$$\bar{U} = T^{-1}UN \quad (30)$$

where  $N$  is a diagonal matrix chosen so that  $\bar{U} = T^{-1}UN$  is normalized to have columns of length 1. A formula for the diagonal elements of  $N$  is

$$N_{ii} = [(U^t(T^{-1})^t T^{-1}U)_{ii}]^{-\frac{1}{2}} \quad (31)$$

(An arbitrary choice about the phase and sign of elements of  $N$  can be made if it is agreed that only the magnitude of coefficients is of interest.) Now

$$\bar{C}_{jk}^i = \frac{1}{2} \sum_{r=1}^n \sum_{\ell=1}^n \sum_{m=1}^n (\bar{U}^{-1})_{ir} \bar{H}_{\ell m}^r \bar{U}_{\ell j} \bar{U}_{mk}$$

Substituting from (29), (30), using (5) and simplifying yields

$$\bar{C}_{jk}^i = \sum_{r=1}^n \sum_{\ell=1}^n \sum_{m=1}^n (N^{-1})_{ir} C_{\ell m}^r N_{\ell j} N_{mk} \quad (32)$$

and, since  $N$  is diagonal, (32) becomes

$$\bar{C}_{jk}^i = N_{ii}^{-1} C_{jk}^i N_{jj} N_{kk} \quad (33)$$

Since the eigenvalues are coordinate independent, formula (1) shows that the  $h_{jk}^i$  transform in the same way as the  $C_{jk}^i$ :

$$\bar{h}_{jk}^i = N_{ii}^{-1} h_{jk}^i N_{jj} N_{kk} \quad (34)$$

Equations (3), (30), (27) and  $\bar{X} = \bar{U}\bar{Y}$  imply that

$$\bar{Y} = N^{-1}Y \quad (35)$$

If  $Z$  and  $Y$  satisfy (6), then it can be shown using (34) and (35) that  $N^{-1}Z$  and  $\bar{Y}$  satisfy

$$\bar{y}_i = \bar{z}_i + \sum_{j=1}^n \sum_{k=1}^n \bar{h}_{jk}^i \bar{z}_j \bar{z}_k \quad (36)$$

Therefore

$$\bar{Z} = N^{-1}Z \quad (37)$$

Equations (37) and (34) imply that the interaction coefficient transforms as

$$\bar{h}_{jk}^i \bar{z}_{j0} \bar{z}_{k0} = N_{ii}^{-1} h_{jk}^i z_{j0} z_{k0} \quad (38)$$

Equations (35), (37) and (38) seem at first glance to imply that the indices  $I1$  and  $I2$  transform as

$$\bar{I}1(i) = N_{ii}^{-1} I1(i) \quad (39)$$

$$\bar{I}2(i) = I2(i) \quad (40)$$

but (39) and (40) only apply in the cases in which the coordinate change does not alter the choice of  $j^*$  and  $k^*$  determining the interaction coefficient of maximum size  $h_{j^*k^*}^i z_{j^*0} z_{k^*0}$  in the formulas (10) and (11).

However, we can suggest modifying the interaction coefficient to

$$\frac{h_{jk}^i z_{j0} z_{k0}}{z_{i0}} \quad (41)$$

and modifying the index  $I2$  to

$$I3(i) = \max_{j,k} \left| \frac{h_{jk}^i z_{j0} z_{k0}}{z_{i0}} \right| \quad (42)$$

The new coefficient (41) and index (42) are constants invariant under coordinate change and are intrinsic to the system.

We consider special cases of the transformation  $T$  in which the formula (31) for  $N$  becomes more simple:

1. Diagonal  $T$  can be interpreted as a transformation which changes the units in which the system states are measured. If  $T$  is diagonal, then

$$N_{ii} = \left[ \sum_{j=1}^n U_{ij}^t U_{ji} T_{jj}^{-2} \right]^{-\frac{1}{2}} \quad (43)$$

Formula (43) generally simplifies to  $N = T$  only when  $T$  is a multiple of the identity matrix.

2. If  $T$  is orthonormal so that  $T^t T = I$ , then  $N = I$  and all the coefficients and indices are invariant under  $T$ .

#### 4.2 Discussion

The transformation formulas (33), (34) and (38) show how the coefficients  $C_{jk}^i$ ,  $h2_{jk}^i$  and  $h2_{jk}^i z_{j0} z_{k0}$  change when the coordinates assumed for the differential equations are changed by a linear transformation. Since the transformation formulas depend on the matrix  $N$  which normalizes the columns of  $U$ , these coefficients are neither independent of the coordinates assumed for the differential equations, nor do they transform as a tensor with respect to those coordinates. Thus the coefficients  $C_{jk}^i$ ,  $h2_{jk}^i$  and  $h2_{jk}^i z_{j0} z_{k0}$  are not intrinsic to the system under study. This can be problematic for quantifying nonlinear interactions with these coefficients. For example, the ranking of these coefficients by size can change when different coordinates are used.

For a general linear transformation of the coordinates assumed for the differential equations, the coefficients  $C_{jk}^i$ ,  $h2_{jk}^i$  and  $h2_{jk}^i z_{j0} z_{k0}$  transform in way that depends in a complicated fashion on the linear transformation. A similarly complicated dependence would also arise in the case of a nonlinear coordinate transformation such as changing phasors from polar coordinates to rectangular coordinates.

A diagonal transformation of coordinates  $T$  (case 1 in subsection 4.1) is an important special case because it represents an independent rescaling of each of the state variables, or, equivalently, a change in units. In this special case, the  $N$  matrix is given by (43) and the coefficients have the nontrivial transformations (33), (34) and (38). In power system models, there is a mixed set of units because the state variables include different physical quantities and these transformations show how the coefficients change when, for example, angles are measured in degrees instead of radians, or when per unit scaling is introduced or removed for some of the states.

One perspective to help explain the transformations of the coefficients  $C_{jk}^i$ ,  $h2_{jk}^i$  and  $h2_{jk}^i z_{j0} z_{k0}$  is as follows: The idea of these coefficients is to transform the system to a standard coordinate system, namely modal coordinates that diagonalize the Jacobian, and to measure the nonlinear interactions in that particular coordinate system. However, there are no unique modal coordinates; any given set of modal coordinates can be independently rescaled to yield another set of modal coordinates. (There appears, at this stage of inquiry, to be no intrinsic way to select one of these sets of modal coordinates as canonical.) The scaling of the modal coordinates is chosen by the scaling of the eigenvectors (columns of  $U$ ). Different coordinate systems for the original differential equations yield different choices of scalings for the modal coordinates (see (35)) and hence different values of the coefficients.

The  $I1$  and  $I2$  indices depend on which interaction coefficient has maximum size. Since the interaction coefficient of maximum size can vary with the coordinate system, the

$I1$  and  $I2$  indices can vary in a nonstandard way when the coordinate system changes. That is, the  $I1$  and  $I2$  indices depend on a ranking by size of the interaction coefficients which is not invariant. (In the absence of this effect, the  $I2$  index would be a constant independent of the coordinate system (see (40)), but the  $I1$  index would vary with the coordinate system (see (39)).)

The most recent work applying normal form analysis [18] mentions the difficulty of quantifying nonlinearity with the  $I1$  and  $I2$  indices in comparing cases at different operating conditions: "However, using these indices, it was difficult to compare the nonlinearity quantitatively because of the scaling of the eigenvectors." This statement is consistent with our results.

We suggest a new coefficient (41) and index (42) which are constants invariant under coordinate change. The new coefficient and index are similar to the noninvariant measures proposed in [15] and their meaning and usefulness should be evaluated in future work.

#### 5 Subsynchronous resonance

We suggest a detailed explanation of the eigenvalue movements in the subsynchronous resonance instability using concepts of strong and weak resonance. The results are illustrated using calculations on the IEEE first benchmark model [6, 11, 1] and an ideal coupled oscillator system and are supported by a theory of perturbations of parameterized matrices.

In the IEEE first benchmark model, the frequency of the subsynchronous electrical mode can be changed by varying the amount of capacitive series compensation. It is well known that as the frequency of the subsynchronous electrical mode in the generator rotor passes near the frequency of a torsional mode, the torsional mode rapidly destabilizes and then stabilizes. We propose that that the destabilization and stabilization are caused by passing close to a pair of strong resonances. Passing close to the first strong resonance causes the destabilization and then passing close to the second strong resonance causes the stabilization.

How does the pair of strong resonances arise? It turns out that the system is close to a weak resonance, and perturbing a weak resonance generally causes a pair of strong resonances to arise.

##### 5.1 Related work by Bowler, Padiyar and Seyranian

In a classic paper [2, example 3], Bowler, Ewart, and Concordia analyze eigenvalue movements in a pair of coupled RLC oscillators to give physical insight into subsynchronous resonance. Our perspective is that the eigenvalue movements in [2, figure 6b] show a pair of strong resonances and

subsequent figures show perturbations of the strong resonances. Section 5.2 shows similar results.

Padiyar [11, section 1.5] associates subsynchronous resonance with the “mode coupling” described by Van Ness [10] in the context of interarea oscillations. It is suggested in [4] that the similar mode coupling described by Van Ness in [16] is a strong resonance phenomenon. Padiyar [11] also describes the mode coupling in subsynchronous resonance in a way consistent with the close eigenvalues and nearly aligned eigenvectors found near strong resonance: “The eigenvalues that are close can result in mode coupling (although not always). Actually, the mode coupling arises from the similarity between eigenvectors.” We can read [11] as strengthening the notion that strong resonance effects occur in subsynchronous resonance.

Seyranian [12, section IIIC] considers the perturbation of a weak resonance of two real eigenvalues into two strong resonances for the vibrational linear system

$$M\ddot{x} + \epsilon B\dot{x} + F = 0 \quad (44)$$

$M$  is positive definite and symmetric and  $F$  is negative definite and symmetric. When  $\epsilon = 0$ , the system is self adjoint and the system has real eigenvalues which can coincide in a weak resonance.

Then  $B$  is assumed to be antisymmetric and the weak resonance is perturbed by considering small, nonzero  $\epsilon$ . This models a small gyroscopic force. The weak resonance perturbs to a pair of strong resonances which cause a “bubble” in which the eigenvalues move off the real axis between the two strong resonances. This case, in which the perturbed eigenvalues pass exactly through the pair of strong resonances, is a perturbation of a weak resonance of real eigenvalues. For subsynchronous resonance we consider below perturbation of a weak resonance of complex eigenvalues.

## 5.2 Two coupled linear oscillators

Before examining subsynchronous resonance, we look at a much simpler case which is easier to analyze. Following [2, example 3], we consider the two linear oscillators

$$\ddot{x} + \dot{x} + \omega^2 x = b\dot{y} \quad (45)$$

$$\ddot{y} + \delta\dot{y} + 100y = a\dot{x} \quad (46)$$

The oscillators are mutually coupled by the terms  $b\dot{y}$ ,  $a\dot{x}$  on the right hand sides of (45), (46). In the absence of this coupling ( $a = b = 0$ ), the first oscillator has damping 0.5 and natural frequency  $\omega$ , and the second oscillator has damping  $\delta/2$  and natural frequency 10. The oscillators can be written in state space form as

$$\frac{d}{dt} \begin{pmatrix} x \\ \dot{x} \\ y \\ \dot{y} \end{pmatrix} = \begin{pmatrix} 0 & 1 & 0 & 0 \\ -\omega^2 & -1 & 0 & b \\ 0 & 0 & 0 & 1 \\ 0 & a & -100 & -\delta \end{pmatrix} \begin{pmatrix} x \\ \dot{x} \\ y \\ \dot{y} \end{pmatrix} \quad (47)$$

We are interested in the resonances and interactions of eigenvalues as the first oscillator natural frequency  $\omega$  is varied to pass near the second oscillator natural frequency 10 for various values of the other parameters. The eigenvalues are the roots of a quartic characteristic equation which we explicitly but messily solve using computer algebra. It is convenient to focus on the two eigenvalues  $\lambda_1$  and  $\lambda_2$  of positive frequency; the complex conjugate eigenvalues with negative frequency move similarly below the real axis.

First suppose that the oscillators are completely uncoupled so that  $a = b = 0$  and that the second oscillator has damping  $\delta = 0$ . Then the first oscillator has eigenvalue  $\lambda_1 = -0.5 + \sqrt{0.25 - \omega^2}$  and the second oscillator has a fixed eigenvalue  $\lambda_2 = 10j$ . The movement of  $\lambda_1$  as  $\omega$  is decreased from 12 to 7 is shown in Fig. 1. There is no interaction between the eigenvalues.

If the damping of the second oscillator is changed to  $\delta = 1$ , its eigenvalue changes to  $\lambda_2 = -0.5 + 9.99j$ , but the movement of  $\lambda_1$  is unchanged and  $\lambda_1$  passes through  $-0.5 + 9.99j$  when  $\omega = 10$  as shown in Fig. 2. Thus for  $\delta = 1$  and no coupling between the oscillators, the two eigenvalues coincide in a weak resonance at  $\omega = 10$ .

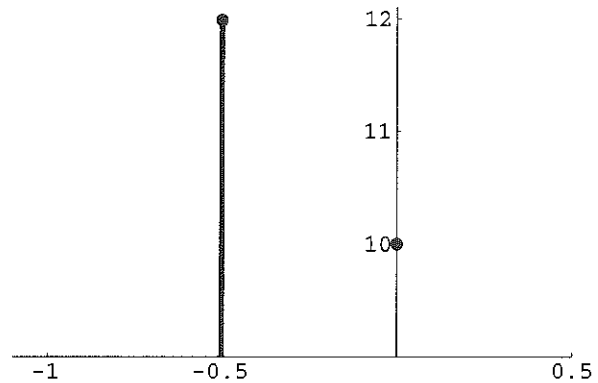


Fig. 1: Linear oscillator eigenvalues as  $\omega$  is decreased from 12 to 7;  $a = b = 0$  (no coupling) and  $\delta = 0$ . Larger dot shows initial position of eigenvalues and movement below frequency 9 is not shown.

Now include the mutual coupling between the oscillators so that  $a = b = 1$ . When the damping  $\delta$  is zero, the eigenvalues interact as shown in Fig. 3. Fig. 3 is a perturbation of Fig. 1 caused by adding the coupling.

To explain the interaction in Fig. 3 in terms of strong resonance effects, we set  $\delta = 1$  and start by perturbing the weak resonance in Fig. 2. Adding the mutual coupling  $a = b = 1$  between the oscillators perturbs the weak resonance in Fig. 2 to Fig. 4. In Fig. 4, we claim that  $\lambda_1$  starts at the top, moves downward, then interacts with  $\lambda_2$  by passing near a strong resonance, moves to the right, moves to the left and then interacts again with  $\lambda_2$  by passing near another strong resonance. The changes of direction

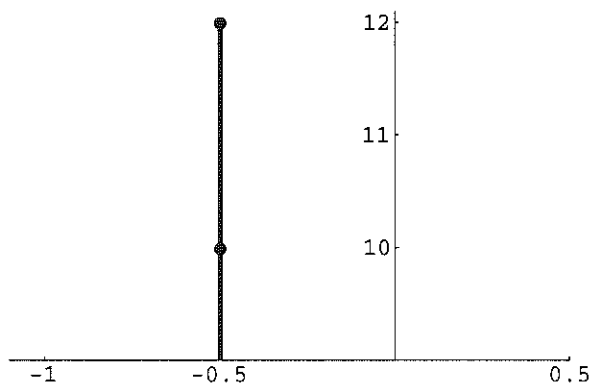


Fig. 2: Linear oscillator eigenvalues as  $\omega$  is decreased from 12 to 7;  $a = b = 0$  (no coupling) and  $\delta = 1$ . Larger dot shows initial position of eigenvalues and movement below frequency 9 is not shown.

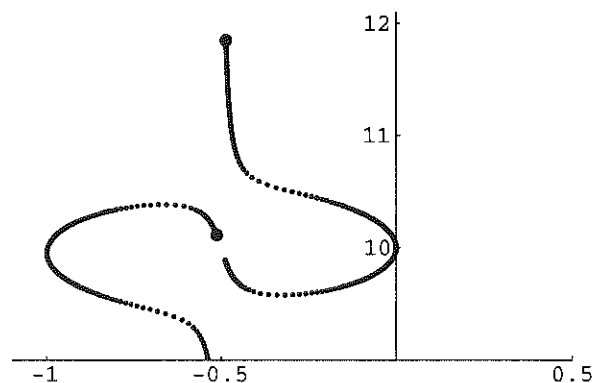


Fig. 4: Linear oscillator eigenvalues near two strong resonances;  $a = b = 1$  (mutual coupling) and  $\delta = 1.0$ .

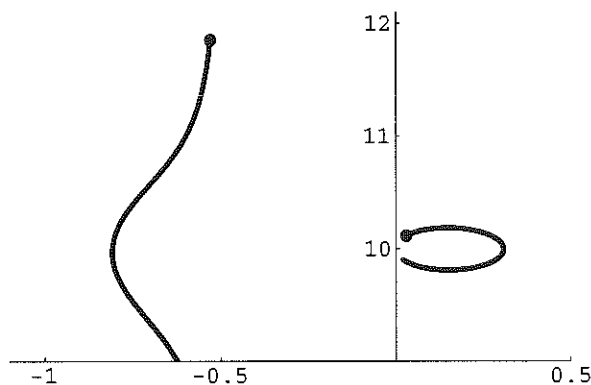


Fig. 3: Linear oscillator eigenvalues as  $\omega$  is decreased from 12 to 7;  $a = b = 1$  (mutual coupling) and  $\delta = 0$ .

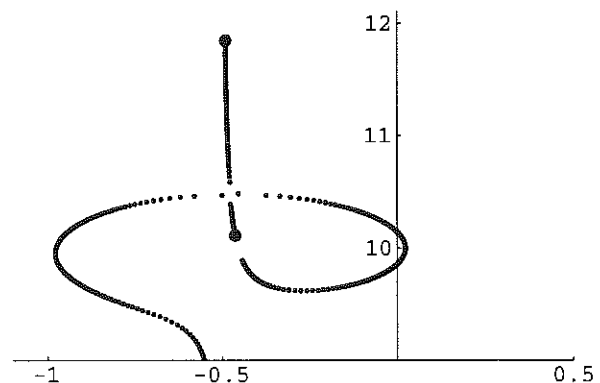


Fig. 5: Linear oscillator eigenvalues showing exact strong resonance in the first interaction;  $a = b = 1$  and  $\delta = 0.91$ .

of eigenvalues when the eigenvalues are close are characteristic of movement near strong resonance [4].

Indeed, we can adjust the damping  $\delta$  near  $\delta = 1$  to find the two strong resonances.  $\delta = 0.91$  makes the first interaction between the eigenvalues an exact strong resonance as shown in Fig. 5.  $\delta = 1.11$  makes the second interaction between the eigenvalues an exact strong resonance as shown in Fig. 6. This confirms the proximity to two strong resonances in Fig. 4.

Now we reduce the damping from  $\delta = 1.0$  in Fig. 4 to  $\delta = 0$  in Fig. 3 and note that the effect of the two nearby strong resonances is still perceptible in the eigenvalue movement. To show more clearly the passage from Fig. 4 to Fig. 3 we show an intermediate case with  $\delta = 0.89$  in Fig. 7. Note that the eigenvalue which becomes unstable during the resonance changes at the damping  $\delta = 0.91$  while passing through the first strong resonance in Fig. 5; this effect is expected [4, 13].

### 5.3 Subsynchronous resonance modal interactions

The first benchmark model was created by the IEEE subsynchronous resonance Task Force [6] as a standard test model to facilitate analysis and comparison of calculations of subsynchronous resonance. The turbine-generator shaft is modeled as 6 masses with torsional springs. There are five torsional modes TM1 through TM5 for the mechanical system with respective natural frequencies 100, 127, 160, 203, 298 radian/s.

The equations and parameters of the IEEE first benchmark model are taken from [11]. The no load case is assumed. The mechanical damping is initially assumed to be zero. The subsynchronous mode frequency is varied by changing the series capacitance  $X_c$  from 0.12 to 0.55 pu. This corresponds to varying the transmission line compensation from 24% to 110%. (It is convenient to extend the compensation to the artificially high value of 110% so that the more dramatic eigenvalue movements of the TM1 resonance can be seen in the results.)

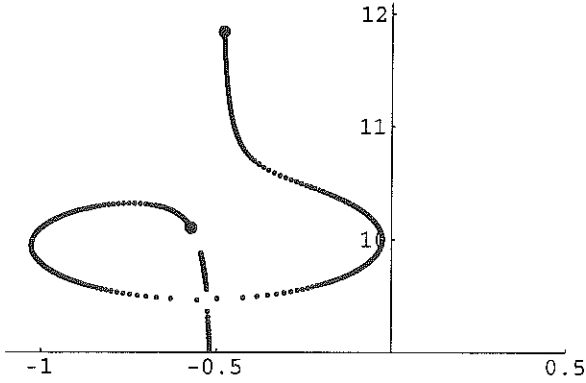


Fig. 6: Linear oscillator eigenvalues showing exact strong resonance in the second interaction;  $a = b = 1$  and  $\delta = 1.11$ .

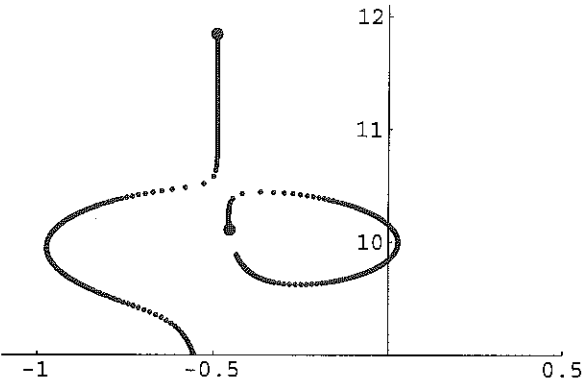


Fig. 7: Linear oscillator eigenvalues;  $a = b = 1$  and intermediate damping  $\delta = 0.89$ .

To first show the eigenvalues without any interaction, we artificially zero the electromagnetic machine torque term by which the electrical system couples to the mechanical system. Then the torsional modes have fixed eigenvalues at the natural frequencies of the generator shaft. The movement of the subsynchronous mode as the series capacitance  $X_c$  varies and the fixed torsional modes TM1, TM2, TM3, TM4 are shown in Fig. 8. In this case, the subsynchronous and torsional eigenvalues do not interact.

When the torque term is restored, the subsynchronous and torsional modes interact in a well known way: as the subsynchronous frequency of rotor currents coincides in turn with each of the torsional mode frequencies, that torsional mode destabilizes and then restabilizes as shown in Fig. 9.

The similarity of form between each modal resonance in Fig. 9 and Fig. 3 is apparent. To further demonstrate the proximity to strong resonance in Fig. 9, we adjust the torsional mode dampings so that modes TM1, TM2, TM3 are close to their pairs of strong resonances as shown in Fig. 10. The dampings are individually tuned ( $D_{EX} = 0.37$ ,  $D_m =$

1.0,  $D_{LPB} = 1.0$ ,  $D_{LPA} = 3.0$ ,  $D_{IP} = 2.5$ ,  $D_{HP} = 2.0$ ) to obtain this special result. Although these torsional dampings are not intended to be realistic, Fig. 10 demonstrates the proximity of subsynchronous resonances in Fig. 9 to pairs of strong resonances.

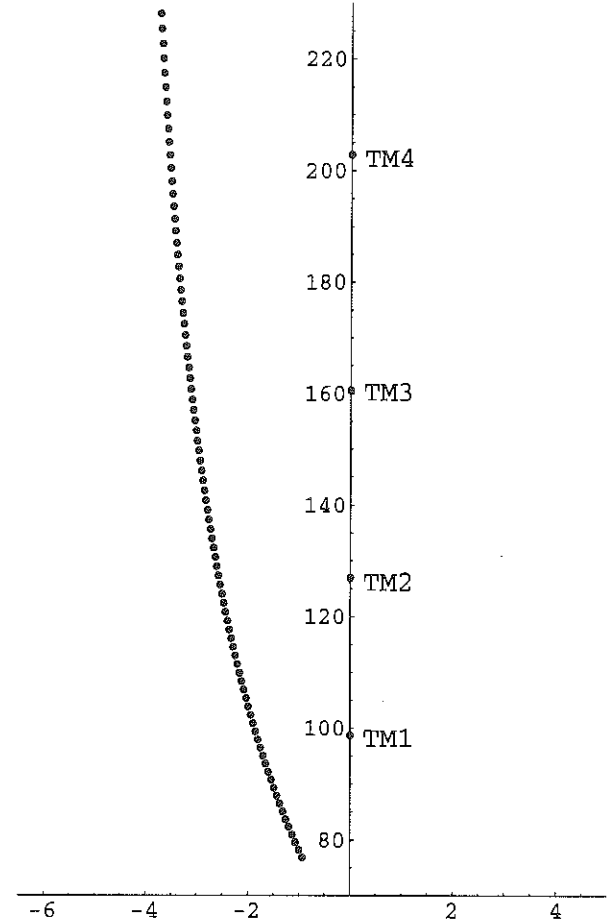


Fig. 8: Subsynchronous mode and torsional modes TM1, TM2, TM3, TM4 with no torque term and hence no interaction in the IEEE first benchmark model.

#### 5.4 Perturbation of a complex weak resonance

Suppose that as a particular parameter  $t$  is varied a system encounters a weak resonance of complex eigenvalues. This section shows why a general perturbation of this situation leads to proximity to two strong resonances.

Assume that analytic power system differential equations have the real parameter  $t$  and the real parameter  $\epsilon$ .  $\epsilon$  is a real parameter controlling the perturbation. The unperturbed system has  $\epsilon = 0$  and has an asymptotically stable equilibrium at  $t = 0$ . Let the Jacobian matrix evaluated at the stable equilibrium be  $J(t, \epsilon)$ . Then  $J$  is a well defined analytic function of  $t$  and  $\epsilon$  near  $(t, \epsilon) = (0, 0)$ . We addi-

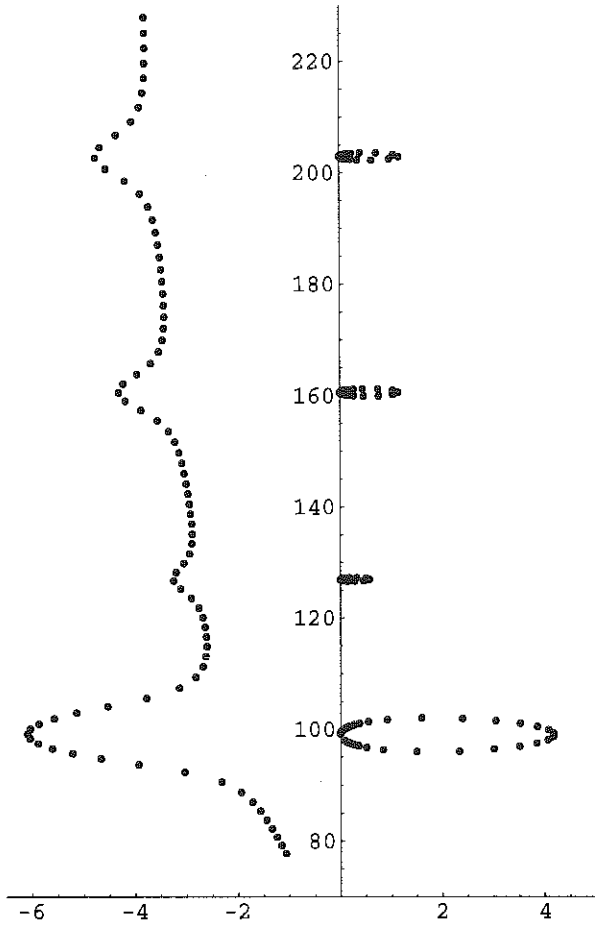


Fig. 9: Subsynchronous resonances between the subsynchronous mode and torsional modes.

tionally assume that the power system differential equations depend analytically on  $t$  when  $t$  is considered to be a complex parameter. Then  $J$  is also analytic in  $t$  as a complex variable.

The unperturbed system is assumed to have a weak resonance between two complex modes at  $t = 0$ . In particular, exactly two eigenvalues of  $J(t, 0)$  coincide at eigenvalue  $\lambda$  in a weak resonance<sup>1</sup> at  $t = 0$ . It follows from the analyticity of the total projection in [8, p. 74] that the two dimensional complex eigenspace corresponding to *both* of these two eigenvalues is an analytic function of  $t$  and  $\epsilon$  near  $(t, \epsilon) = (0, 0)$ . By restricting  $J(t, \epsilon)$  to this eigenspace, we obtain a  $2 \times 2$  complex matrix  $M(t, \epsilon)$  which captures the eigenstructure of the two modes of interest.  $M(t, \epsilon)$  is an analytic function of  $t$  and  $\epsilon$  near  $(t, \epsilon) = (0, 0)$ . We write

$$M(t, \epsilon) = \begin{pmatrix} a(t, \epsilon) & b(t, \epsilon) \\ c(t, \epsilon) & d(t, \epsilon) \end{pmatrix} \quad (48)$$

<sup>1</sup>Two other complex conjugate eigenvalues of  $J(t, 0)$  also coincide in a weak resonance at eigenvalue  $\lambda^*$  at  $t = 0$ .

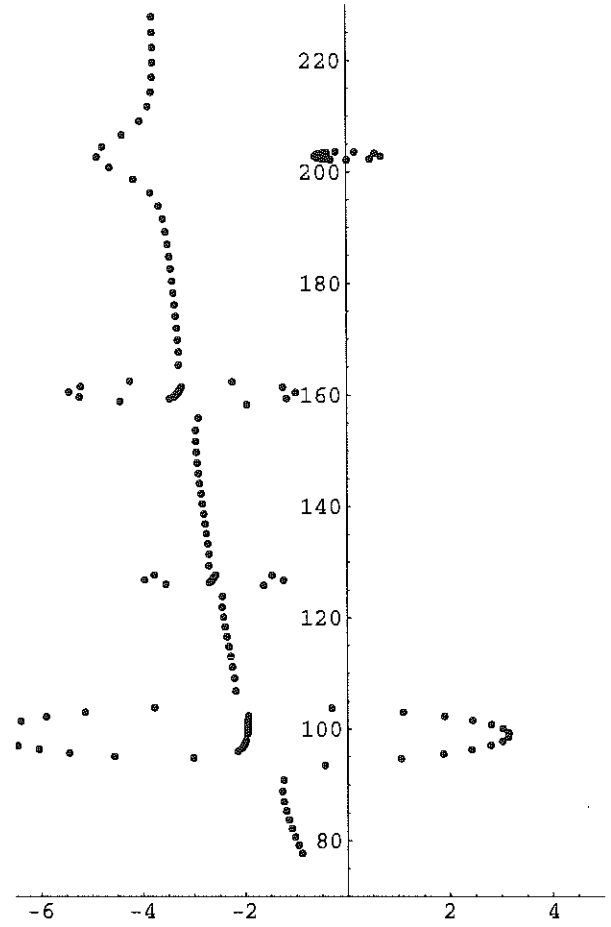


Fig. 10: Subsynchronous resonances perturbed with artificial torsional dampings to indicate some of the nearby pairs of strong resonances.

The assumption of weak resonance at  $(t, \epsilon) = (0, 0)$  implies that

$$M(0, 0) = \begin{pmatrix} \lambda & 0 \\ 0 & \lambda \end{pmatrix} \quad (49)$$

Now we generalize the real parameter  $t$  to the complex parameter  $\tau$  and write (with some abuse of notation)  $M(\tau, \epsilon)$  for the matrix  $M$  parameterized by the complex parameter  $\tau$ . This generalization to a complex parameterization with  $\tau$  is convenient because complex strong resonance is codimension 1 in complex parameter space [4] and is typically encountered as  $\tau$  is varied. The real parameterization by  $t$  will be restored at the end.

Define the complex function

$$\Delta(\tau, \epsilon) = (\text{Trace}\{M(\tau, \epsilon)\})^2 - 4 \text{Det}\{M(\tau, \epsilon)\} \quad (50)$$

$$= (a - d)^2 + 4bc \quad (51)$$

Since the eigenvalues of  $M$  are  $\frac{1}{2}(a+d) \pm \frac{1}{2}\sqrt{\Delta}$ , the condition for coincident and resonant eigenvalues is  $\Delta = 0$ . Indeed,



the condition for strong resonance of  $M$  is  $\Delta = 0$  and  $bc \neq 0$  and the condition for weak resonance of  $M$  is  $\Delta = 0$  and  $bc = 0$ . Definition (50) shows that  $\Delta$  is coordinate independent. It was ensured above that  $J$  and the two dimensional complex eigenspace were analytic in  $\tau$  and it follows that  $M$  and  $\Delta$  are analytic in  $\tau$ .

It follows from (49) that

$$\Delta(0, 0) = 0 \quad (52)$$

We want to find out how this root corresponding to a weak resonance changes under perturbation. We compute some derivatives of  $\Delta$  and evaluate them at  $(\tau, \epsilon) = (0, 0)$ . The derivative of  $\Delta$  with respect to  $\tau$  evaluated at  $(0, 0)$  is written as  $\Delta_\tau|_0$ . The derivatives with respect to  $\tau$  are complex derivatives.

$$\begin{aligned} \Delta_\tau &= 2(a - d)(a_\tau - d_\tau) + 4b_\tau c + 4bc_\tau \\ \Delta_\epsilon &= 2(a - d)(a_\epsilon - d_\epsilon) + 4b_\epsilon c + 4bc_\epsilon \\ \Delta_\tau|_0 &= 0 \\ \Delta_\epsilon|_0 &= 0 \\ 2A = \Delta_{\tau\tau}|_0 &= 2[(a_\tau - d_\tau)^2 + 4b_\tau c_\tau]|_0 \\ 2B = \Delta_{\epsilon\epsilon}|_0 &= 2[(a_\epsilon - d_\epsilon)^2 + 4b_\epsilon c_\epsilon]|_0 \\ 2H = \Delta_{\tau\epsilon}|_0 &= 2[(a_\tau - d_\tau)(a_\epsilon - d_\epsilon) + 2b_\tau c_\epsilon + 2b_\epsilon c_\tau]|_0 \end{aligned}$$

Then for small  $(\tau, \epsilon)$  we have the Taylor series

$$\Delta(\tau, \epsilon) = A\tau^2 + 2H\tau\epsilon + B\epsilon^2 + h.o.t. \quad (53)$$

We make the generic assumptions that  $A \neq 0$  and  $B \neq 0$ . Then, factoring the quadratic terms

$$\begin{aligned} \Delta(\tau, \epsilon) &= A^{-1} \left( A\tau + \left( H + \sqrt{H^2 - AB} \right) \epsilon \right) \\ &\quad \left( A\tau + \left( H - \sqrt{H^2 - AB} \right) \epsilon \right) \\ &\quad + h.o.t. \end{aligned} \quad (54)$$

shows that, to leading order, the complex roots  $\tau$  of  $\Delta(\tau, \epsilon) = 0$  lie on two straight lines passing through the origin as  $\epsilon$  is varied near zero. This implies that the double root at  $(\tau, \epsilon) = (0, 0)$  corresponding to a weak resonance typically perturbs to two strong resonances in the complex plane near zero as  $\epsilon$  changes from zero. The strong resonances occur at complex values of  $\tau$  which vary approximately linearly with respect to  $\epsilon$  for small  $\epsilon$ .

Now we restrict the parameterization from the complex parameter  $\tau$  to the real parameter  $t$ . Since the two strong resonances generally lie in the complex plane off the real axis,  $M(t, \epsilon)$  generally does not encounter either of the strong resonances as  $t$  varies near zero. However, for small  $\epsilon$ , the proximity of the strong resonances to the origin of the complex plane implies that  $M(t, \epsilon)$  does pass close to the strong resonances as  $t$  varies near zero. Thus, the power system passes close to two strong resonances at a general, small perturbation of a weak resonance.

## 6 Conclusions

*Normal form analysis methods near strong resonance.* We give examples to show that the normal form analysis coefficients  $C_{jk}^i$ ,  $h_{jk}^i$  and  $h_{jk}^2 z_{j0} z_{k0}$  can become very large near strong resonance between eigenvalues. Indices based on these coefficients also become large. This can occur even when the system in the original coordinates has small nonlinearity. The transformation to modal coordinates used when defining the coefficients introduces a large nonlinearity into the system and this large nonlinearity is quantified by the coefficients. In effect, the coefficients, which were intended to detect nonlinear modal interactions, also detect the strong modal resonance which occurs in the system linearization. Care is warranted in interpreting large values of these coefficients as evidence of system nonlinearity when eigenvalues are close together.

*Variance of normal form analysis coefficients and indices under changes of coordinates and units.* We examine how the coefficients  $C_{jk}^i$ ,  $h_{jk}^i$  and  $h_{jk}^2 z_{j0} z_{k0}$  vary when the power system differential equations are expressed in different coordinates or different units. Under a general coordinate change of the power system differential equations, these coefficients are not constants and do not transform as tensors. Thus the coefficients are not intrinsic to the system. This can be problematic for quantifying nonlinear interactions with these coefficients. The behavior of the coefficients under coordinate change is related to the nonuniqueness of modal coordinates and the eigenvector scaling induced by the coordinates assumed for the power system differential equations. The dependence of the indices  $I1$  and  $I2$  on the interaction coefficient ranking and some additional dependence of  $I1$  on the coordinate system can cause these indices to vary in a nonstandard way. We suggest a new interaction coefficient (41) and index (42) which are invariant under coordinate change and intrinsic to the system. Future work should evaluate the meaning and use of these new measures.

*Subsynchronous resonance and perturbations of a weak resonance.* We analyze a system passing through a complex weak resonance as a single parameter is varied and show that a general perturbation leads to passing close to two strong resonances. This behavior is confirmed in a linear system of two coupled oscillators (also see [2]). We suggest that subsynchronous resonance can be understood as proximity to pair of strong resonances perturbed from a complex weak resonance and this behavior is shown by results from the IEEE first benchmark model for subsynchronous resonance. This case study on subsynchronous resonance is a start to clarifying the general implications of proximity to complex weak resonance.

## Acknowledgements

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## Appendix

Since the arguments for the real and complex resonance cases are very similar, we only present the real resonance case. The first task is to show that for a fixed  $X_0 \neq 0$ ,  $Z_0 \neq 0$  as  $\mu \rightarrow 0$ . Equation (8) can be written as

$$Z_0 = U^{-1}X_0 - \begin{pmatrix} Z_0^* h^2 Z_0 \\ Z_0^* h^2 Z_0 \end{pmatrix} \quad (55)$$

Multiplying by  $U$  gives

$$UZ_0 = X_0 - \begin{pmatrix} Z_0^* (Uh^2)^1 Z_0 \\ Z_0^* (Uh^2)^2 Z_0 \end{pmatrix} \quad (56)$$

where

$$(Uh^2)^1 = \frac{\epsilon}{4(1+\mu)} \begin{pmatrix} \frac{2}{(-1+\sqrt{\mu})(-1+3\sqrt{\mu})} & \frac{2}{(-1-\sqrt{\mu})(-1+\sqrt{\mu})} \\ \frac{2}{(-1-\sqrt{\mu})(-1+\sqrt{\mu})} & \frac{2}{(-1-3\sqrt{\mu})(-1-\sqrt{\mu})} \end{pmatrix}$$

$$(Uh^2)^2 = \frac{\epsilon}{4(1+\mu)} \begin{pmatrix} \frac{-2+4\sqrt{\mu}}{(-1+\sqrt{\mu})(-1+3\sqrt{\mu})} & \frac{-2}{(-1-\sqrt{\mu})(-1+\sqrt{\mu})} \\ \frac{-2}{(-1-\sqrt{\mu})(-1+\sqrt{\mu})} & \frac{-2-4\sqrt{\mu}}{(-1-3\sqrt{\mu})(-1-\sqrt{\mu})} \end{pmatrix}$$

Notice that  $Uh^2$  is bounded as  $\mu \rightarrow 0$  and that (13) shows that  $U$  is bounded as  $\mu \rightarrow 0$ . It follows that if  $Z_0 \rightarrow 0$  as  $\mu \rightarrow 0$ , then letting  $\mu \rightarrow 0$  in (56) implies that  $X_0 = 0$ , which is a contradiction. Therefore  $Z_0 \neq 0$  as  $\mu \rightarrow 0$ .

$Z_0 \neq 0$  as  $\mu \rightarrow 0$  implies that for  $j = 1$  or  $j = 2$ ,  $z_{0j} \neq 0$  as  $\mu \rightarrow 0$ . Also (16) implies that  $h^2 z_{jj} \rightarrow \infty$  as  $\mu \rightarrow 0$ . It is now a straightforward exercise in analysis to prove that there is a sequence  $\mu_1, \mu_2, \mu_3, \dots$  tending to zero such that  $h^2 z_{jj} z_{j0} z_{j0}$  evaluated at  $\mu_1, \mu_2, \mu_3, \dots$  tends to infinity. (This conclusion is weaker than  $h^2 z_{jj} z_{j0} z_{j0} \rightarrow \infty$  as  $\mu \rightarrow 0$ , but it is adequate for our purpose.)

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Discussion by  
Costas Vournas and B. M. Nomikos  
on  
**Strong Resonance Effects in Normal Form Analysis ...**  
by Ian Dobson  
and  
**On Modal Resonance and Interarea Oscillations ...**  
by L. Jones, G. Andersson, V. Knyazkin

The first paper provides a detailed and extremely useful discussion on modal resonance and normal form analysis with application to the subsynchronous resonance phenomenon, while the second paper reviews useful results on the resonance between electromechanical oscillation modes. In both papers older work is referenced as evidence of near strong resonance effects in interarea electromechanical oscillation modes of actual systems.

In this discussion we present an example of a realistic power system model, in which a proximity to a strong, non-diagonalizable resonance between electromechanical oscillation modes is identified during the process of tuning of a Power System Stabilizer. We also contribute some comments on the effect of open loop zeros.

#### Resonance case

A 10-machine realistic model of the Hellenic Interconnected Power System was developed in [A]. This model was used in [B] to demonstrate the successive design of Power System Stabilizers.

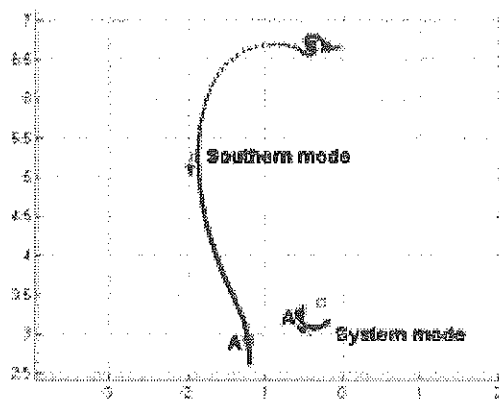


Fig. 1 Electromechanical mode resonance

Fig. 1 from [B] shows part of the root locus for increasing PSS gain of one generator. As seen, increasing PSS gain forces down the frequency of an intra-area mode (South vs. North of Greece) so that it passes near a resonance with the interarea, or

system mode (Greece with respect to the external interconnection).

The near-resonance at points AA of Fig. 1 is a non-diagonalizable, strong resonance, as shown by the alignment of the two mode eigenvectors shown in Fig. 2. Indeed both modes correspond to an oscillation of all the machines in phase, except the one on which the PSS is applied (gen. no. 9).

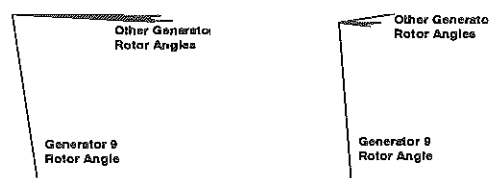


Fig. 2 Eigenvectors at points AA of Fig. 1

#### On the role of open-loop zeros

Another question refers to the role played by transfer function zeros during PSS tuning. Fig. 3 is a root locus plot referring to another instance of PSS tuning.

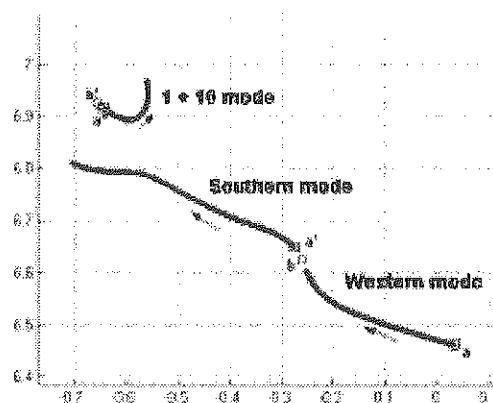


Fig. 3 Poles and zeros "billiard" effect

As seen in Fig. 3, by increasing the PSS gain the critical mode is moving towards the zero that was effectively canceling the

Southern mode pole in the open loop transfer function. At the same time, the Southern mode passes near a resonance with the local mode 1+10.

This picture looks as though the poles are playing billiards exchanging the open loop zeros to which they converge for high PSS gain.

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## Discussions on Session VIII: SYSTEM ANALYSIS Part 1

**Chairman (D. Hill):** Please think of some questions. Costas has a prepared discussion to kick off with.

**C. Vournas (NTUA):** I have a copy of this discussion I'm submitting for the papers of L. Jones on the one hand, and Ian Dobson on the other. The work that we have been done on eigenvalues and power system stability, actually verifies the theory of the first paper presented here. Two things that I'd like to show: the first one is an example that I have seen in a model of the Greek power system of the '80s, 1990 to be more exact. The two different modes, which we track in this work, are two electromechanical ones. The one is that I call southern-mode, an oscillation in the south-north direction, . The lower frequency one is the system mode, which is an oscillation of all the machines in phase. As shown in Fig. 1 of my discussion, at point A, you see that the eigenvectors have converged.. This is the type of problem that was puzzling me when I was doing parameter optimization. Suddenly Ian threw some light on it, by showing it's a near-strong resonance phenomenon. So I would appreciate any comment from Ian either now or in writing.

**I. Dobson:** I might say that the example of near-strong resonance is between control mode and electric mechanical mode. I think it is very interesting in Costas' s result. Here is a definite case of mechanical mode showing near-strong resonance. It's, with mentioning in Costas's paper at Porto, the Portugal conference, he has an example of near strong resonance very helpful in trying to get to the bottom of the power system.

**I. Hiskens:** I think Ian has done an admiral job of explaining things.

**Chairman:** While we're on this topic, with all of these speakers here, any question on the resonance effect?

**N. Yorino (Hiroshima University):** I would like to ask Professor Dobson. I'm quite impressed about your presentation. I studied the internal resonance about 10 years ago. That is by second order non-linearity, the resonance occurs without a controller. In your previous discussion, there was no general statement about that. In the discussion, there is interaction between modes where PSS was equipped. So, I'd like to know whether it is PSS that makes the resonance occur.

**I. Dobson:** We only have 4 or 5 examples of this. I'd expect that PSS is not required for this phenomenon. My reason is if you look at systems in general not necessarily power system models, they do commonly

show near-strong modes close together. If you have some confidence, in terms of a couple of interesting and general ways, then one would be this. But I think it's our best guess at present. We are open to see in many cases eigenvalues don't interact, because they are sufficiently de-coupled in some way - maybe one is quite different partially power system a little bit part of different power system structure and interact always. I certainly don't know how is our priority now, and I hope we can find out.

**C. Vournas:** I'd like to comment on this. You can also find near-strong resonance by playing around with excitation system parameters. But I guess the most practical result is with the power system stabilizer. Let's say the practical result when designing stabilizers was that you should not allow the oscillation frequency to change, even though with higher gain you might increase damping, because the eigenvalues may resonate and they can suddenly change direction and turn to the right.

**Chairman:** Ok, we might to move to coherency. Any question on that topic?

**V. Ajjarapu:** Professor Liu showed generators are on one side, coupled together. What happens if you had distributed generation if you want to come up with equivalencing?

**C. C. Liu:** The algorithm does not really depend on any kind of proximity like that. What's important is their electrical proximity sitting together. So I don't think it's going to change that algorithm in that sense. But there is one more thing about this, for example, if you want to apply that to emergency control, say, islanding application, then you want to make sure the demand is somewhat balanced within the island. There are concepts for that kind of applications and your colleague V. J. Vittal is doing that. So this is sort of an interesting application for an old topic. But the voltage characteristics can open up new dimensions. Right now we only look at the rotor angle swings. How about the voltages? Are the voltages going to behave the same in the same area, and not in other areas? That means different grouping with rotor angles, so there is some interesting implication if you keeping thinking about how the system behaves.

**Chairman:** How would you pursue that you can think putting in other dynamics induction models? Is that worth pursuing?

**C.-C. Liu:** I think so. What we have done includes excitation systems, so that is sort of the first order item. We did load models a little bit, but we haven't got very much done there. But I'm sure it's going to make a difference also. The most popular tool, probably the EPRI DYNRED, dynamic reduction, and my understanding is that tool does not really include the characteristics I'm talking about here, so I think there is still quite a bit to do it.

**P.-A. Lof (ABB):** I have a question concerning the number of clusters to be chosen for large systems. I'd like you to comment on that. Also, 10% seems to be very impressive. Could you comment something further on the results of your work?

**C. C. Liu:** The first question is about clusters. You can see my algorithm starts with a magic K. Tell me how many groups you want and I will figure out what's the grouping for you. So I think that's going to need some judgement about how the system behaves. When a system starts to oscillate, how many areas, which areas oscillate with respect with each other. So I don't think there is a magic answer to that question. The 10% question came because they are going to do the real time simulator, the RTDS. The capacity is limited, so the model can not be too big. All practical power systems are big. So that's why we have to reduce to that. We tried the algorithms from the literature, and nothing that gets close to that 10%. So one important thing you might think about - steady state equivalent in the textbooks. When you try to reduce a large circuit to a small circuit, before and after reduction, make sure the power flows match, because that's why they are equivalent. But when you look at coherency, we don't actually require that. That's a very interesting discrepancy. So my answer to your question is that you can match that then the result would be much better.

**I. Erlich:** Professor Liu, have you used the King algorithm for classification or coping? Now for classification, you can use hierarchical algorithms, it's a measuring distance between the variables. You can see the distance between two grouping steps. Have you compared with them? Why did you choose K means algorithm?

**C. C. Liu:** We compared with Joe Chow's method, and that doesn't really have the K means grouping. But it does use the cosine product to measure the coherency, and then use that index to be compared with other type of clustering techniques. But I'm sure there will be other techniques, and I can not see that one technique will be much better than this.

**B. Lee:** In terms of bifurcation, I have observed many cases of this system. I observed similar results that Professor Dobson presented today but I couldn't present it in time domain simulations. Today I'm very glad

to see your sub-synchronous resonance example. So my question is for Professor Dobson. As I know, you're dealing with the equilibrium point. But it is not a question of damping, if you look at the simulation result, it doesn't look like a point of attractor. What I guess is it maybe a little to some period solution. So in the case, we may need to look at this eigenvalue. Could you make some comments on my question?

**I. Dobson:** Yes. I think what is happening in the context of what we are discussing here is the strong resonance caused to move in such a way that it moves across the stability boundary. So it becomes bifurcation, and in an oscillatory instability. To study that periodic solution, one needs to locate multipliers or eigenvalue maps, so however you want to express. So again this is a situation of the strong resonance affect being a precursor to its instability, then causes you problems.

**C. Vournas:** The definition I'm using for bifurcation is the one given in Dobson's paper in Davos, where he clearly discriminated between the saddle node bifurcation with a single 0 eigenvalue, and the case where you can have algebraic multiplicity of eigenvalues, but geometrically you only have one eigenvector. So this type of fold, even if you have multiple eigenvalues, but you only have one eigenvector, then your actual state space curves with respect to the parameter space, so you have a limit, you can not go beyond this point in your state space. So I'm using the terms fold and SNB, with definition exactly as in Ian's paper in Davos. In catastrophe theory, in general they use the term fold liberally, or maybe with other definitions that I'm not aware of. About the catastrophe theory, I know they have this in case. This one I saw very briefly is given in the paper by Kwatny and others.

**P. Sauer:** The question is for Costas. Dobson may be tempted to comment as well. In the world of loadability, we need a margin, we want to stay by some safe distance. So some with proximity in terms of transfer megawatts, but that causes a lot of problems because a lot of these are based on VAR limits. Things suddenly pop up and it's difficult to use sensitivity. How do you back off from your loadability limit and determine the margin?

**C. Vournas:** It's not addressed entirely, but indirectly it is. We define the normal vector, so you have the direction in the parameter space in which to move in order to get away from your loadability. Even better than using the standard normal vector, with the generalized normal vector, you can compute the sensitivity of your margin to the limit, and compute the sensitivity with respect to any parameter. Whether the parameter is that you have in your parameter space or any other parameter like reactive or anything of the kind. So the follow-up paper will have the property to tune certain parameters of loadability.

**C. Canizares:** Just follow upon what Pete just said. I guess we accept you're doing what you just mentioned. Figure out parameters, and parameter space which way to move away in generation to determine the safe margin to that boundary. I guess we've done what Costas has done. So I guess it is feasible that if I propose some similar question as well. So to give you a sensitivity, you just got to be careful that you got to re-compute them, because as you said it the limits tend to pop up.

**I. Dobson:** As you increase your loading or transfer, all sorts of crazy stuff can happen in your continuation, you can switch so you can have voltage limit. All that can happen. The loadability limit or whether it's a bifurcation, then if you look at the normal vector, that gives you a correct sensitivity, despite the fact that your system equation has changed as you went along this process you can put any complicated stuff in, you still get the correct sensitivity. This is an advantage of doing this, you can turn one transfer capability or margin calculation sensitivity of it with the respect everything is inside, and then start exploring and those other things. It is in fact the correct linear sensitivity. Could I add another comment on Costas's paper? I just wanted to comment that works for transfer capability ATC type calculations, when you're hitting some thermal limit or voltage magnitude limit, I think because you did a very careful job of modeling, it generalizes what you're first thinking of.

**C. Vournas:** I did not really look beyond the case of excitation limits. The difference is that the switching of the overexcitation limiter is part of the physics of the system. It is an automatic device. Obviously you could use similar formulation, because it's an optimization problem with inequality constraints. In OPF literature, there are many studies. It's not really new. Maybe what is new is that switching is part of system dynamics. So maybe in the future, other devices can be modeled this way. In ATC you have to assume that some operators will do something to keep you exactly on the limit. This is not the case usually.

**T. Van Cutsem:** I would like to say that I fully agree with either the discussion and the question of Pete Sauer. I would like to say that where your sensitivity apply to a set of equations that is not valid, in this case the rating point. One typical example is when you have one generator under limit at the maximum loadability point, and you would like to compute the sensitivity with respect to your voltage set point in the base case. This is a little tricky to do. It requires caution.

**Chairman:** We have somewhat closely related papers. Ian's is on inverse problems, a general method for looking at a range of questions. Then Venkata's on plotting stability boundary and the recent last result on multiple load flow solutions.

# Inverse Problems in Power Systems

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**Abstract**—Large disturbances in power systems often initiate complex interactions between continuous dynamics and discrete events. Such behaviour can be modeled in a systematic way by a set of differential-algebraic equations, modified to incorporate impulse (state reset) action and constraint switching. The paper presents a practical object-oriented approach to implementing the DAIS model. The systematic nature of the DAIS model enables efficient computation of trajectory sensitivities, which in turn facilitate algorithms for solving inverse problems. The paper outlines a number of inverse problems, including parameter uncertainty, parameter estimation, boundary value problems, border-collision bifurcations, locating critically stable trajectories, and optimal control.

**Keywords:** Dynamic modeling, power system dynamics, hybrid systems, inverse problems.

## I. INTRODUCTION

Interactions between continuous dynamics and discrete events are an intrinsic part of power system dynamic behaviour. Devices that obey physical laws typically exhibit continuous dynamics. Examples range from generators and their controllers at the system level, through to capacitors and inductors within power electronic circuits. On the other hand, event-driven discrete behaviour is normally associated with rule-based components. Examples in this latter category include protection devices [1], tap-changing transformers [2], power electronic switches [3] and supervisory control [4]. Limits within physical devices also fall into this category; an event occurs when a controller signal saturates or a FACTS device encounters its maximum/minimum firing angle.

To illustrate continuous/discrete interactions in power systems, consider a disturbance consisting of an initiating event, such as a lightning strike on a transmission line, followed by protection action to remove the fault. The fault would disturb the steady-state balance between the electrical and mechanical torques on generator shafts, causing angles and frequencies to respond dynamically. In parallel, protection relays should detect the fault and decide on the appropriate response. Trip signals are sent to circuit breakers, which disconnect the faulted feeder after a small (mechanical) time delay. Meanwhile, oscillations induced in intermachine angles may or may not be stable. Removal of the faulted line could lead to overloading of other feeders, and their subsequent tripping. The consequent increased demand for reactive power may activate generator over-

excitation protection, causing a reduction in terminal voltage, increased system losses, further overloading of feeders and finally system disintegration. Whilst this scenario seems pessimistic, it has occurred, to the detriment (and annoyance) of many consumers!

Similar continuous/discrete interactions exist across all layers of power systems. At the market layer, for example, system measurements and participant inputs are interpreted in terms of market rules to generate events that affect the physical system.

In all cases, discrete events influence continuous dynamics, which in turn trigger new events. Modeling and simulation must accurately capture these interactions. Power system simulation has generally evolved to the point where the continuous/discrete nature of dynamic behaviour is fairly accurately replicated. However it is common to find event handling treated as an *ad hoc* addition to continuous state simulation. The nature of inverse problems dictates a more systematic *hybrid systems* approach to capturing continuous/discrete interactions.

Power system analysis normally addresses *forward problems*. Given a system model and a set of parameters, system response can be determined. However the disturbance scenario outlined above motivates analysis questions that are classed as *inverse problems* [5]. Such a disturbance would generate recordings from Wide Area Measurement Systems [6]. Those measurements could be used to improve estimates of parameters of system models [7], [8]. This is an inverse problem; the measured response is given, and a model is used to infer parameter values. It's easy to postulate other inverse problems. For example, what are the minimal changes in controllable parameters, perhaps generator MW and/or voltage setpoints, that would avoid cascading tripping of overloaded feeders or voltage dip problems or instability? How significantly do certain parameters, e.g., load voltage dependence, impact system behaviour?

Traditionally such inverse problems have been addressed by repeated solution (simulation) of forward problems. However systematic modeling provides the foundation for algorithms that address inverse problems directly.

The paper has the following structure. Section II presents a systematic representation of hybrid systems that is applicable for analysis of power system dynamics. Implementation issues are discussed in Section III. Inverse problems are considered in Section IV, and conclusions are presented in Section V.

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## II. HYBRID SYSTEM REPRESENTATION

### A. Background

Power systems are an important example of hybrid systems, which are characterized by:

- continuous and discrete states;
- continuous dynamics;
- discrete events, or triggers;
- mappings that define the evolution of discrete states at events.

Conceptually such systems can be thought of as an indexed collection of continuous dynamical systems

$$F_q(\dot{x}, x, y) = 0, \quad (1)$$

along with a mechanism for ‘jumping’ between those systems, i.e., for switching between the various  $F_q$ . Each system is indexed by the discrete state  $q$ , whilst  $x$  and  $y$  are the continuous dynamic and algebraic states respectively. The jumping reflects the influence of the discrete event behaviour, and is dependent upon both a trigger condition and a discrete state evolution mapping. Overall system behaviour can be viewed as a sequential patching together of dynamical systems, with the final state of one dynamical system specifying the initial state for the next.

### B. Simulation model

Various abstract models, such as Petri nets and hybrid automata [9], [10], [11], provide a framework for establishing rigorous mathematical representations of physical devices and systems. However those representations are not immediately applicable to forward problems (via simulation), much less inverse problems. A model that captures the full richness of hybrid system behaviour, yet has a form suitable for simulation, is required.

Simulation techniques and properties are well established for differential-algebraic (DAE) systems [12]. Therefore the proposed hybrid system model is adapted from that basic form by incorporating impulsive action and switching of algebraic equations, giving the *DA Impulsive Switched* (DAIS) model

$$\dot{x} = f(x, y) + \sum_{j=1}^e \delta(y_{e,j}) (h_j(x, y) - x) \quad (2)$$

$$0 = g(x, y) \equiv g^{(0)}(x, y) +$$

$$\sum_{i=1}^d \left( g^{(i-)}(x, y) + u(y_{d,i}) (g^{(i+)}(x, y) - g^{(i-)}(x, y)) \right) \quad (3)$$

where

- $x \in \mathbb{R}^n$  are dynamic states, and  $y \in \mathbb{R}^m$  are algebraic states;
- $\delta(\cdot)$  is the Dirac delta;
- $u(\cdot)$  is the unit-step function;
- $f, h_j : \mathbb{R}^{n+m} \rightarrow \mathbb{R}^n$ ;
- $g^{(0)}, g^{(i\pm)} : \mathbb{R}^{n+m} \rightarrow \mathbb{R}^m$ ; some elements of each  $g^{(\cdot)}$  will usually be identically zero, but no elements of the

composite  $g$  should be identically zero; the  $g^{(i\pm)}$  have the same general form as  $g$  and are defined via (3), leading to a recursive structure for  $g$ ;

- $y_d, y_e$  are selected elements of  $y$  that trigger algebraic switching and state reset (impulsive) events respectively;  $y_d$  and  $y_e$  may share common elements.

The impulse and unit-step terms of the DAIS model can be expressed in alternative forms:

- Each impulse term of the summation in (2) can be expressed in the state reset form

$$x^+ = h_j(x^-, y^-) \quad \text{when } y_{e,j} = 0 \quad (4)$$

where the notation  $x^+$  denotes the value of  $x$  just after the reset event, whilst  $x^-$  and  $y^-$  refer to the values of  $x$  and  $y$  just prior to the event. This form motivates a generalization to an implicit mapping  $h'_j(x^+, x^-, y^-) = 0$ .

- The contribution of each  $g^{(i\pm)}$  in (3) can be expressed as

$$g^{(i)}(x, y) = \begin{cases} g^{(i-)}(x, y) & y_{d,i} < 0 \\ g^{(i+)}(x, y) & y_{d,i} > 0 \end{cases} \quad i = 1, \dots, d$$

with (3) becoming

$$0 = g(x, y) \equiv g^{(0)}(x, y) + \sum_{i=1}^d g^{(i)}(x, y). \quad (5)$$

This form is often more intuitive than (3).

Equations (2),(3) are a reformulation (and slight generalization) of the model proposed in [13].

It can be convenient to establish the partitions

$$x = \begin{bmatrix} \underline{x} \\ z \\ \lambda \end{bmatrix}, \quad f = \begin{bmatrix} \underline{f} \\ 0 \\ 0 \end{bmatrix}, \quad h_j = \begin{bmatrix} \underline{h}_j \\ \underline{h}_j \\ \lambda \end{bmatrix} \quad (6)$$

where

- $\underline{x}$  are the continuous dynamic states, for example generator angles, velocities and fluxes;
- $z$  are discrete dynamic states, such as transformer tap positions and protection relay logic states;
- $\lambda$  are parameters such as generator reactances, controller gains and switching times.

This partitioning of the differential equations  $f$  ensures that away from events,  $\underline{x}$  evolves according to  $\dot{\underline{x}} = \underline{f}(x, y)$ , whilst  $z$  and  $\lambda$  remain constant. Similarly, the partitioning of the reset equations  $h_j$  ensures that  $\underline{x}$  and  $\lambda$  remain constant at reset events, but the dynamic states  $z$  are reset to new values given by  $z^+ = \underline{h}_j(x^-, y^-)$ .

Remark:

- The DAIS model assumes constant state space dimension  $x \in \mathbb{R}^n$ ,  $y \in \mathbb{R}^m$  across events. This differs from some other hybrid system implementations, for example [14], where the state dimension is allowed to vary upon component switching. The DAIS formulation is not restrictive, though it may require carrying some

‘inactive’ states following an event. Maintaining constant state dimension has a number of advantages: 1) the variational equations describing trajectory sensitivities, presented in Appendix A, have a simpler form, and 2) switched states are more easily incorporated into objective functions of optimization-based inverse problems.

Initial conditions for the model (2)-(3) are given by  $x(t_0) = x_0$  and  $y(t_0) = y_0$ , where  $y_0$  is a solution of  $g(x_0, y_0) = 0$ . Note that in solving for  $y_0$ , the constraint switching described by (3) must be taken into account. This establishes the initial discrete state  $q_0$ .

The flows of  $x$  and  $y$  are defined as

$$\phi(x_0, t) = \begin{bmatrix} \phi_x(x_0, t) \\ \phi_y(x_0, t) \end{bmatrix} = \begin{bmatrix} x(t) \\ y(t) \end{bmatrix} \quad (7)$$

where  $x(t)$  and  $y(t)$  satisfy (2)-(3), along with initial conditions,

$$\phi_x(x_0, t_0) = x_0 \quad (8)$$

$$g(x_0, \phi_y(x_0, t_0)) = 0. \quad (9)$$

### C. Trajectory sensitivities

Trajectory sensitivities provide a way of quantifying the variation of a trajectory resulting from (small) changes to parameters and/or initial conditions [13], [15]. To obtain the sensitivity of the flows  $\phi_x$  and  $\phi_y$  to initial conditions  $x_0$ , the Taylor series expansion of (7) is formed. Neglecting higher order terms gives

$$\Delta x(t) = \frac{\partial x(t)}{\partial x_0} \Delta x_0 \equiv x_{x_0}(t) \Delta x_0 \quad (10)$$

$$\Delta y(t) = \frac{\partial y(t)}{\partial x_0} \Delta x_0 \equiv y_{x_0}(t) \Delta x_0. \quad (11)$$

Using the partitioning (6),  $x_0$  incorporates parameters  $\lambda$ , so sensitivity to initial conditions  $x_0$  includes parameter sensitivity. Equations (10)-(11) describe the changes  $\Delta x(t)$  and  $\Delta y(t)$  in a trajectory, at time  $t$  along the trajectory, for a given (small) change in initial conditions  $\Delta x_0 = [\Delta x_0^t \ \Delta z_0^t \ \Delta \lambda^t]^t$ . The time-varying partial derivatives  $x_{x_0}$  and  $y_{x_0}$  are known as *trajectory sensitivities*. An overview of the variational equations describing the evolution of these sensitivities is provided in Appendix A.

Along smooth sections of the trajectory, the trajectory sensitivities evolve according to a linear time-varying differential-algebraic system (20)-(21). For large systems, these equations have high dimension. However the computational burden is minimal when an implicit numerical integration technique such as trapezoidal integration is used to generate the trajectory. An overview of this result is provided in Appendix B. More complete details of both appendices are given in [13].

## III. IMPLEMENTATION

### A. Flexible component interconnection

Models of large systems are most effectively constructed using a hierarchical or modular approach. With such an

approach, components are grouped together as subsystems, and the subsystems are combined to form the full system. This allows component and subsystem models to be developed and tested independently. It also allows flexibility in interchanging models.

The interactions inherent in hybrid systems are counter to this decomposition into subsystems and components. However the algebraic equations of the DAIS model can be exploited to achieve the desired modularity. Each component or subsystem can be modeled autonomously in the DAIS structure, with ‘interface’ quantities, e.g., inputs and outputs, established as algebraic variables. The components are then interconnected by introducing simple algebraic equations that ‘link’ the interface variables. This is similar to the connections concept of [16]. Note that all interconnections are non-causal [17], i.e., no rigid input-output arrangement of components is assumed.

To illustrate this linking concept, consider a case where the  $n$ -th algebraic state of component  $j$ , denoted  $y_{j,n}$ , is required by component  $k$ . In the model of component  $k$ , the corresponding quantity would appear as an algebraic variable  $y_{k,m}$ . The connection is made via the simple algebraic equation  $y_{j,n} - y_{k,m} = 0$ . In general, all linking can be achieved by summations of the form

$$\sum c_k y_{i,j} = 0 \quad (12)$$

where  $c_k$  is  $\pm 1$ . Notice that all connections are external to the component models.

The linking strategy results in an interesting structure for the Jacobian<sup>2</sup>

$$J = \begin{bmatrix} f_x & f_y \\ g_x & g_y \end{bmatrix}.$$

Components contribute square blocks down the diagonal of  $f_x$  and flattened rectangular blocks along the diagonal of the upper section of  $g_y$ . The lower section of  $g_y$  is an incidence matrix, with  $\pm 1$ 's given by the external connections (12). Figure 1 illustrates this structure. (This particular matrix corresponds to a ten generator representation of the Nordel power system [8].) A Jacobian structure like that of  $J$  was identified in [18], where a similar arrangement of components and connections was used in the development of an optimal power flow.

The structure and values of the lower connection sub-matrix of  $J$ , and hence  $F_{x*}$ , are fixed for all time. This can be exploited in the factorization of  $F_{x*}$  to improve the efficiency of solving (26)-(27). The efficiency improvement can be significant, as these equations are solved at every time step.

In general, components and subsystems of any form can be modeled, provided they are structured with interfacing algebraic variables that can be linked to other components. Noise and/or random disturbances can be added to the model by linking components that generate random signals.

<sup>2</sup>This Jacobian has the same structure as the matrix  $F_{x*}$ , given by (28), that is required for implicit numerical integration and for computing trajectory sensitivities.

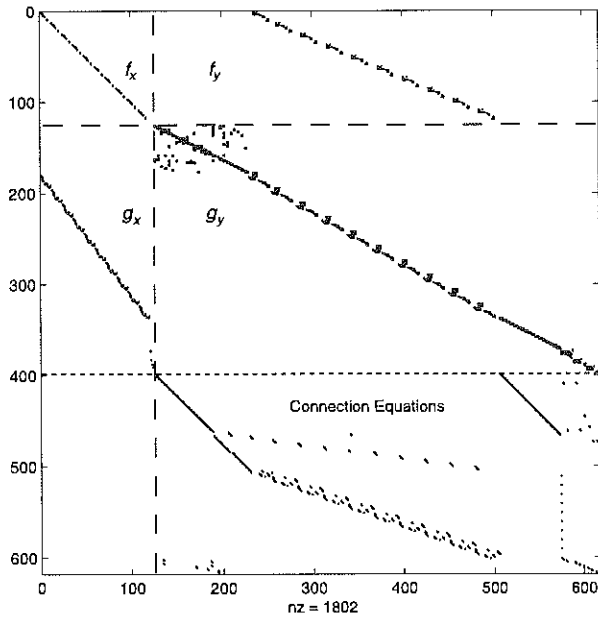


Fig. 1. Sparsity structure of Jacobian  $J$ .

#### B. Matlab implementation

The proposed modular approach to constructing hybrid systems has been implemented in Matlab [19]. In this implementation, the system is described by a data file that contains `model_data` information and (separate) `connections` details. Each component of the system contributes an entry to `model_data` that consists of the component name, initial values for  $x_0$  and  $y_0$ , and background parameters. Links between components are fully described in `connections` using the form given by (12).

Every component is described by a file that calculates values for  $f$ ,  $g$  and  $h$ , and sparsely stored elements of the partial derivative matrices  $f_x$ ,  $f_y$ ,  $g_x$ ,  $g_y$ ,  $h_x$  and  $h_y$ . These component files are re-usable, i.e., case independent, and reside in a component library. Relative indexing is used for Jacobian elements, as each component model is autonomous. (All connection information is externally defined.) Hence within a model, the indexing of Jacobian elements uses only local equation and variable numbering. The simulation kernel uses these relative indices, along with knowledge of equation and variable dimensions across all models, to generate the location of each element in the full matrices, i.e., the absolute indices. The actual matrices are never built explicitly, but rather are stored sparsely.

#### C. Symbolic differentiation

As indicated above, partial derivative matrices are calculated and stored sparsely by component files. Hand derivation of these partial derivatives can be tedious for large complicated models. Therefore the process has been automated through the use of symbolic differentiation [19]. Symbolic manipulation has been utilized in power system

simulation previously [20], though the implementation was quite different.

The generation of a component file begins with an analytical model in the DAIS form. The analytical model must be unambiguously mapped into a character representation that can be manipulated symbolically. It is also important that this mapping does not restrict the implementation of the DAIS form. Fortunately the DAIS model structure is well suited to such translation. All elements of the model can be clearly and uniquely identified.

A Matlab function has been developed for translating the input model representation into a component file that can interact with the simulation kernel [19]. Building the  $f$ ,  $g$  and  $h$  equations involves relatively straightforward character string manipulation. Generating the partial derivatives is more challenging. Firstly, equations and variable strings are converted to symbols. Symbolic differentiation produces partial derivatives that must be simplified and converted back to strings. If the final expression is zero, the derivative is discarded, as matrices are stored sparsely.

Component files are generated off-line and stored in the component library. Therefore symbolic manipulation does not slow simulation speed.

#### D. Computation of junction points

Switching and reset events generically do not coincide with the time instants of the numerical integration process. However simulation accuracy depends upon correct location, between integration time steps, of events [21].

A simple check of sign changes in trigger variables  $y_d$  and  $y_e$  at each integration step will reveal most events [13]. However this check fails to detect events where the associated trigger variables change sign an even number of times over a time step. A more thorough search for events is required, though a trade-off must be made between search accuracy and computational cost. An efficient approach proposed in [21] uses interpolation polynomials generated by a BDF integration method [12].

### IV. INVERSE PROBLEMS

System analysis is often tantamount to understanding the influence of parameters on system behaviour, and applying that knowledge to achieve a desired outcome. The 'known' information is the desired outcome. The parameters that achieve that outcome must be deduced. Because of the inverse nature of the problem, the process has traditionally involved repeated simulation of the model. This can be time consuming and frustrating, as the relationship between parameters and behaviour is often not intuitively obvious.

Systematic modeling, as presented in previous sections, allows the development of new tools that can solve inverse problems directly, albeit via iterative techniques. The DAIS model is conducive to the efficient generation of trajectory sensitivities. Those sensitivities quantify, to first order, the effects of parameters on dynamic behaviour. They

therefore underlie the development of gradient-based algorithms.

The following subsections present a range of inverse problems. Algorithms that address those problems are outlined. This list is not exhaustive, but seeks to provide an overview of the possibilities that follow from systematic modeling.

#### A. Parameter uncertainty

System parameters can never be known exactly. In fact uncertainty in some parameters, e.g., load models, can be quite high. Quantifying the effects of parameter uncertainty is not strictly an inverse problem, but illustrates the usefulness of trajectory sensitivities.

Because of the uncertainty in parameters, investigation of system behaviour should (ideally) include multiple studies over a range of parameter values. However simulation of large systems is computationally intensive. Such an investigation would be extremely time consuming. The more practical approach is to assume that a *nominal* set of parameters provides an adequate representation of behaviour over the full range of values. This may not always be a good assumption though.

A computationally feasible (though approximate) approach to repeated simulation is to generate a first order approximation of the trajectory for each set of perturbed parameters. The first order approximation is obtained by truncating the Taylor series expansion of the flow  $\phi$ . Using (10)–(11), this gives

$$\phi(x_{0_2}, t) = \phi(x_{0_1}, t) + \begin{bmatrix} x_{x_0}(t) \\ y_{x_0}(t) \end{bmatrix} (x_{0_2} - x_{0_1}) \quad (13)$$

where  $x_{x_0}(t)$ ,  $y_{x_0}(t)$  are computed along the nominal trajectory  $\phi(x_{0_1}, t)$ . Therefore if the trajectory sensitivities  $x_{x_0}(t)$ ,  $y_{x_0}(t)$  are available for a nominal trajectory, then (13) can be used to provide a good estimate of trajectories  $\phi(x_{0_2}, t)$  corresponding to other (nearby) parameter sets. (Recall that parameters  $\lambda$  are embedded in  $x_0$ .)

The computational burden involved in generating the approximate trajectories is negligible. Given the nominal trajectory and associated trajectory sensitivities, new (approximate) trajectories can be obtained for many parameter sets. Therefore a Monte-Carlo technique can be employed to quantify the uncertainty in a trajectory:

- parameter sets are randomly generated,
- first order approximations are obtained using (13).

Figure 2 illustrates this process for a simple example where a disturbance initiates interactions between a tap-changing transformer and a dynamic load. The dark line shows the nominal trajectory. The bound around that trajectory was obtained using 200 randomly chosen sets of parameters. Further details can be found in [22].

Statistics quantifying the uncertainty in system behaviour due to parameter uncertainty can be obtained from the Monte-Carlo simulation. For example, it's possible to state the probability that a disturbance would initiate pro-

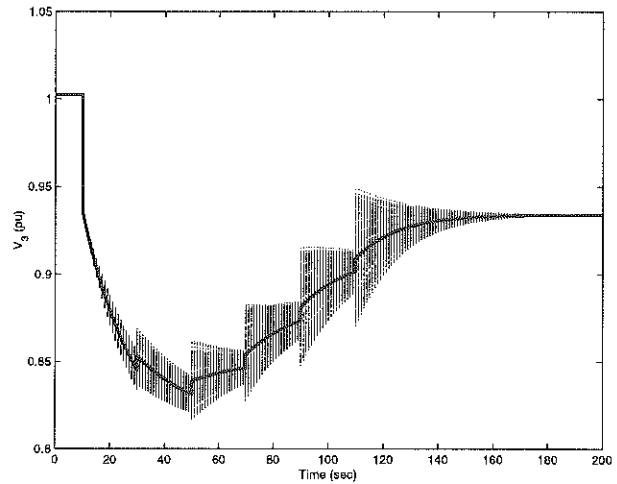


Fig. 2. Trajectory bounds.

tection operation or that a voltage would fall below some predetermined threshold.

Another approach to assessing the significance of parameter uncertainty is via worst case analysis [23]. This involves finding the values of parameters (within specified bounds) that induce the greatest deviation in particular system variables, for example voltages. The algorithm can be formulated as a constrained optimization, and is truly an inverse problem. Such optimization problems are discussed as part of later inverse problems.

#### B. Parameter estimation

System-wide measurements of power system disturbances are frequently used in event reconstruction to gain a better understanding of system behaviour [7], [24]. In undertaking such studies, measurements are compared with the behaviour predicted by a model. Differences are used to tune the model, i.e., adjust parameters, to obtain the best match between the model and the measurements. This process requires a systematic approach to,

- 1) identifying *well-conditioned* parameters that can be estimated reliably from the available measurements, and
- 2) obtaining a best estimate for those parameters.

It is shown in [8] that trajectory sensitivities can be used to guide the search for well-conditioned parameters, i.e., parameters that are good candidates for reliable estimation. Large trajectory sensitivities imply the corresponding parameters have leverage in altering the model trajectory to better match the measured response. Small trajectory sensitivities, on the other hand, imply that large changes in parameter values would be required to significantly alter the trajectory. Parameters in the former category are well-conditioned, whereas the latter parameters are ill-conditioned. Only parameters that influence measured states can be identified. A parameter may have a significant influence on system behaviour, but if that influence is not observable in the measured states, then the

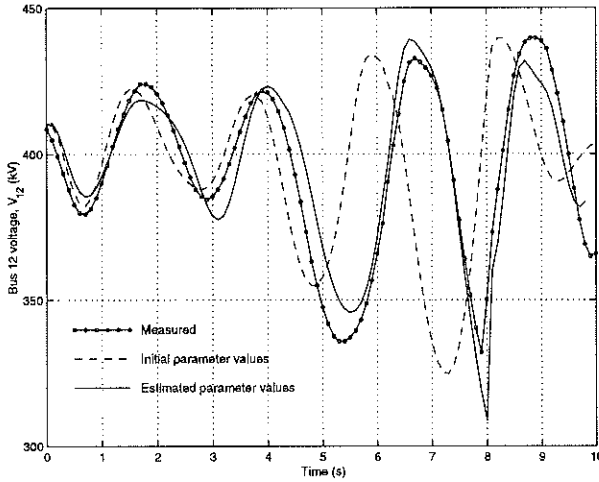


Fig. 3. Parameter estimation.

parameter is not identifiable. The concept of identifiability is explained more formally in [25].

A parameter estimation algorithm that is based on a Gauss-Newton iterative procedure is presented in [8]. The algorithm minimizes a nonlinear least-squares cost

$$\mathcal{V}(\theta) = \frac{1}{2} \|\tilde{y}(\theta) - ms\|_2^2$$

where  $ms$  are the sampled measurements of the disturbance,  $\tilde{y}(\theta)$  are the flows provided by the model that correspond to the measured quantities, and  $\theta$  are the unknown parameters. This minimization can be achieved (locally at least) by the iterative scheme

$$\begin{aligned} S(\theta^j)^t S(\theta^j) \Delta\theta^{j+1} &= S(\theta^j)^t (\tilde{y}(\theta^j) - ms) \\ \theta^{j+1} &= \theta^j - \alpha^{j+1} \Delta\theta^{j+1} \end{aligned} \quad (14)$$

where  $\alpha^{j+1}$  is a scalar that determines the parameter update step size<sup>3</sup>. The matrix  $S$  is built from the trajectory sensitivities  $\tilde{y}_\theta$ , i.e., sensitivity of model flows  $\tilde{y}$  to parameters  $\theta$ . The invertibility of  $S^t S$  relates directly to identifiability [25].

The parameter estimation process is illustrated in Figure 3. A voltage measurement from a disturbance on the Nordel system [8] is shown. The figure also shows the simulated voltage trajectory for the initial parameter values, and the tuned values obtained after convergence (in four iterations) of (14). The improvement is clear.

Remarks:

- 1) Parameter estimation via (14) is not restricted to smooth systems. In fact, it is possible to estimate parameters that underlie event descriptions (provided measurements capture an occurrence of the event.)
- 2) For large systems, feasibility of the Gauss-Newton algorithm is dependent upon efficient computation of

<sup>3</sup>Equation (14) could be solved by inverting  $S^t S$ , however faster and more numerically robust algorithms are available [26].

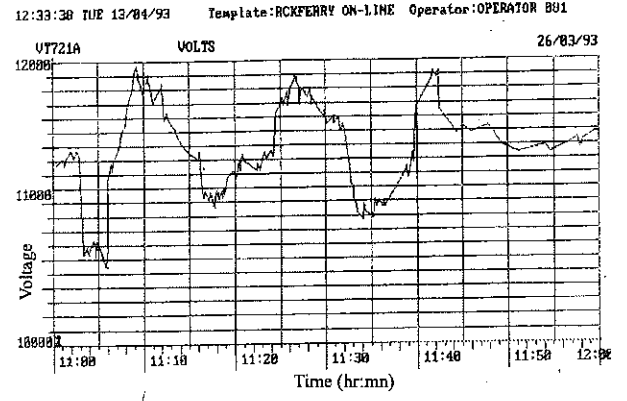


Fig. 4. Oscillations in distribution system voltage.

trajectory sensitivities. This underlines the importance of systematic modeling.

### C. Boundary value problems

It is interesting to consider boundary value problems of the form

$$r(x_0, x(t_f)) = 0 \quad (15)$$

where  $t_f$  is the final time, and  $x(t)$  is the trajectory that starts from  $x_0$  and is generated by (2),(3). The initial values  $x_0$  are variables that must be adjusted to satisfy  $r$ . (Though  $r$  may directly constrain some elements of  $x_0$ .) To establish the solution process, (15) can be rewritten

$$r(x_0, \phi_x(x_0, t_f)) = 0, \quad (16)$$

which has the form  $\tilde{r}(x_0) = 0$ . Boundary value problems can be solved by shooting methods [27], [28], which are a combination of Newton's method for solving (16) along with numerical integration for obtaining the flow  $\phi_x$ . Newton's method requires the Jacobian

$$J = \frac{\partial r}{\partial x_0} + \frac{\partial r}{\partial \phi_x} x_{x_0}(t_f), \quad (17)$$

which is dependent upon the trajectory sensitivities evaluated at  $t_f$ .

Boundary value problems *per se* are uncommon in power systems. However an application of increasing importance is the calculation of limit cycles (sustained oscillations). Oscillations have been observed in a variety of power systems, from generation [29] to distribution. This latter case is illustrated in Figure 4, where the oscillations were driven by interactions between transformer tapping and capacitor switching.

To solve for limit cycles, (16) can be written

$$x_0 - \phi_x(x_0, T) = 0$$

where  $x_0$  lies on the limit cycle and  $T$  is its period. Solution of this boundary value problem via a shooting method requires  $x_{x_0}(T)$ , which is exactly the Monodromy matrix [27], [30]. The eigenvalues of this matrix determine the stability of the limit cycle.

#### D. Border-collision bifurcations

When a system trajectory encounters the operating characteristic of a protection device, a trip signal is sent to circuit breakers. If the trajectory almost touches the operating characteristic but just misses, no trip signal is issued. The bounding (separating) case corresponds to the trajectory grazing, i.e., just touching, the operating characteristic but not crossing it. This is a form of global bifurcation; it separates two cases that have significantly different outcomes. Numerous names exist for this phenomena, including C-bifurcation, switching-time bifurcation and border-collision bifurcation.

Examples of such bifurcations can be found in many application areas. They are particularly important in power electronic circuits, where zero-crossings are fundamental to control strategies, and to the switching of self-commutating devices [31]. In fact it has been shown that border-collision bifurcations can provide a path to chaos in simple DC-DC converters [32].

Identifying the critical values of parameters that correspond to a border-collision bifurcation is an inverse problem. Let the operating/switching characteristic be described by  $b(x, y) = 0$ . A trajectory will be tangential to that characteristic at the point  $[x^* \ y^*]^t = \phi(x_0^*, t^*)$  given by

$$\begin{aligned} b(x^*, y^*) &= 0 \\ (b_x - b_y g_y^{-1} g_x)|_{(x^*, y^*)} f(x^*, y^*) &= 0. \end{aligned}$$

The critical values of parameters are given by  $x_0^*$ . This is a special form of boundary value problem. Shooting methods provide the basis for gradient-based algorithms.

#### E. Critically stable trajectories

Theoretically it's possible to find parameter values that cause a disturbed system to be critically stable, i.e., the trajectory lies exactly on the stability boundary. A perturbation of a parameter in one direction would lead to stability, whereas a perturbation in the opposite direction would cause instability. In practice, the critical values of parameters cannot be determined exactly. However an algorithm that approaches those values has been developed [33].

The algorithm is based on the assumption that the limit set consists only of isolated equilibria. Under that assumption, the stability boundary is composed of the stable manifolds of type-1 unstable equilibrium points (UEPs) that lie on the boundary [34]. Therefore an unstable trajectory must pass through the stable manifold of a type-1 UEP. If a disturbance to the system is critically cleared, the trajectory will lie on the stable manifold of a UEP, and approach that UEP in infinite time. A trajectory that is nearly critically cleared, whether stable or unstable, will pass close by that UEP. But generally the UEP is unknown. Energy function methods require a knowledge of this 'controlling UEP' [35]. The proposed algorithm does not.

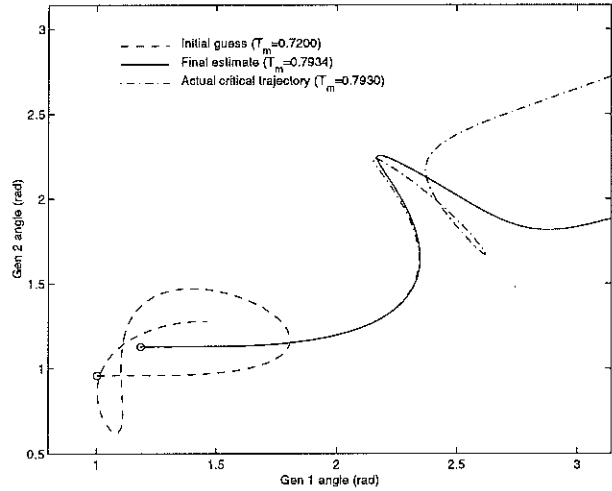


Fig. 5. Convergence to critical trajectory.

Equilibria satisfy

$$f(x, y) = 0$$

along with algebraic constraints (3). Therefore proximity to equilibria can be established using the quadratic cost function

$$\mathcal{J}(x, y) = \frac{1}{2} f(x, y)^t W f(x, y) \quad (18)$$

where  $W$  is a diagonal matrix that is used to weight the relative importance of the various elements of  $f$ . Near an equilibrium point, the cost  $\mathcal{J}(x, y)$  becomes small. By monitoring  $\mathcal{J}(x, y)$  along a trajectory, points that are local minima can be found. Many of those points indicate proximity to equilibria.

The proposed algorithm is based on the idea that  $\mathcal{J}(x, y)$  defines a hypersurface in the variables  $t$  (time) and  $x_0$  (initial conditions and parameters). Starting from a local minimum in  $\mathcal{J}$  on the initial trajectory,  $t$  and  $x_0$  can be varied to minimize  $\mathcal{J}$  over that hypersurface. As  $\mathcal{J}$  is minimized, the minimum point moves closer towards a UEP, and hence the trajectory moves closer to passing through that UEP.

The implementation of this algorithm in [33] uses a Gauss-Newton technique for minimizing  $\mathcal{J}$ . The gradient information required by the minimization process is provided by trajectory sensitivities. Figure 5 illustrates the process. In that example, the critical value of mechanical torque  $T_m$  at one of the generators was obtained. It can be seen from the figure that the actual critical trajectory undergoes convoluted behaviour in the vicinity of the UEP. This introduces local minima into the cost function  $\mathcal{J}$ , masking the location of the global minimum (exact critical value). However the local and global minima are close, so the error introduced by convergence to the wrong point is small.

### F. Optimal control

Optimization problems arise frequently in the analysis of power system dynamics. Examples range from tuning generator AVR/PSSs to determining the optimal location, amount and switching times for load shedding [36]. All these problems can be formulated using a Bolza form of objective function

$$\min_{\theta, t_f} I(x, y, \theta, t_f) \quad (19)$$

where

$$I = \varphi(x(t_f), y(t_f), \theta, t_f) + \int_{t_0}^{t_f} \psi(x(t), y(t), \theta, t) dt,$$

$\theta$  are the design parameters, i.e., the parameters adjusted to achieve the objective, and  $t_f$  is the final time.

The solution of (19) for hybrid systems is complicated by the discontinuous behaviour at events. However these complications largely disappear under the assumption that the order of events does not change as  $\theta$  and  $t_f$  vary, i.e., no border-collision bifurcations occur. This assumption is common throughout the literature, though it is expressed in various ways: transversal crossings of triggering hypersurfaces are assumed in [37], existence of trajectory sensitivities is assumed in [38], and [39] assumes all flows have the same *history*. All statements are equivalent.

Under that assumption, and other mild assumptions, it is concluded in [39] that if  $I$  is continuous in its arguments then a solution to (19) exists. Further, [38] shows that if  $I$  is a smooth function of its arguments, then it is continuously differentiable with respect to  $\theta$  and  $t_f$ . The minimization can therefore be solved using gradient-based methods. Trajectory sensitivities underlie the gradient information.

If the event ordering assumption is not satisfied,  $I$  may be discontinuous. The optimization problem then takes on a combinatorial nature, as each continuous section of  $I$  must be searched for a local minimum.

Other optimization problems do not naturally fit the form (19) of the objective function. Cascaded tap-changing transformers provide an interesting example [40]. Minimizing the number of tap change operations is equivalent to minimizing the number of crossings of triggering hypersurfaces. Such a problem, by definition, does not satisfy the earlier assumption requiring constant ordering of events. This minimization is best addressed using switching control design techniques [41], though the solution process is not yet well established.

### G. Technical issues

Changes in event ordering, as discussed in the previous subsection, influence all gradient-based algorithms for solving inverse problems. The effect is similar to power flow solution when reactive power limits change status. Algorithms usually converge, though with a slower convergence rate and a reduced region of convergence.

Another interesting aspect of hybrid systems is that trajectories may not be unique in reverse time, even though

they are unique in forward time. In other words, the same final value  $\phi(x_0, t_f)$  can be reached from different initial values  $x_0$ . In such cases, the trajectory sensitivity matrix  $x_{x_0}(t_f)$  is singular. This matrix underlies solution algorithms for numerous inverse problems, for example (17). An approach to addressing this issue is to decompose  $x_0$  into components that influence  $\phi(x_0, t_f)$  and those that do not. Attention is then restricted to the former group. This is an area of on-going research.

## V. CONCLUSIONS

The response of power systems to large disturbances often involves interactions between continuous dynamics and discrete events. Such behaviour can be captured by a model that consists of a set of differential-algebraic equations, modified to incorporate impulse (state reset) action and constraint switching (DAIS model).

Models of large systems are most effectively constructed using a modular or object-oriented approach. The desired modularity can be achieved in a practical way with the DAIS model. Components and/or subsystems are modeled autonomously, with connections established via simple algebraic equations. This object-oriented model structure is amenable to symbolic manipulation.

Systematic modeling allows the development of tools for solving inverse problems, including parameter uncertainty and estimation, boundary value problems, locating border-collision bifurcations and critically stable trajectories, and optimal control. The DAIS model is conducive to the efficient generation of trajectory sensitivities. Those sensitivities underlie gradient-based algorithms for inverse problems.

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## APPENDIX

### I. TRAJECTORY SENSITIVITY EQUATIONS

Away from events, where system dynamics evolve smoothly, the sensitivities  $x_{x_0}$  and  $y_{x_0}$  are obtained by differentiating (2)–(3) with respect to  $x_0$ . This gives

$$\dot{x}_{x_0} = f_x(t)x_{x_0} + f_y(t)y_{x_0} \quad (20)$$

$$0 = g_x(t)x_{x_0} + g_y(t)y_{x_0} \quad (21)$$

where  $f_x \equiv \partial f / \partial x$ , and likewise for the other Jacobian matrices. Note that  $f_x$ ,  $f_y$ ,  $g_x$ ,  $g_y$  are evaluated along the trajectory, and hence are time-varying matrices. It is shown in Appendix B that the solution of this (potentially high order) DAE system can be obtained as a by-product of solving the original DAE system (2)–(3).

Initial conditions for  $x_{x_0}$  are obtained from (8) as

$$x_{x_0}(t_0) = I$$

where  $I$  is the identity matrix. Initial conditions for  $y_{x_0}$  follow directly from (21),

$$0 = g_x(t_0) + g_y(t_0)y_{x_0}(t_0).$$

Equations (20),(21) describe the evolution of the sensitivities  $x_{x_0}$  and  $y_{x_0}$  between events. However at an event, the sensitivities are often discontinuous. It is necessary to calculate *jump conditions* describing the step change in  $x_{x_0}$  and  $y_{x_0}$ . For clarity, consider a single switching/reset



event, so the model (2)-(5) reduces to the form

$$\dot{x} = f(x, y) \quad (22)$$

$$0 = \begin{cases} g^-(x, y) & s(x, y) < 0 \\ g^+(x, y) & s(x, y) > 0 \end{cases} \quad (23)$$

$$x^+ = h(x^-, y^-) \quad s(x, y) = 0. \quad (24)$$

Let  $(x(\tau), y(\tau))$  be the point where the trajectory encounters the hypersurface  $s(x, y) = 0$ , i.e., the point where an event is triggered. This point is called the *junction point* and  $\tau$  is the *junction time*. Assume that the trajectory encounters the triggering hypersurface transversally.

Just prior to event triggering, at time  $\tau^-$ ,  $x$  and  $y$  are given by

$$\begin{aligned} x^- &= x(\tau^-) = \phi_x(x_0, \tau^-) \\ y^- &= y(\tau^-) = \phi_y(x_0, \tau^-) \end{aligned}$$

where

$$g^-(x^-, y^-) = 0.$$

Similarly,  $x^+, y^+$  are defined for time  $\tau^+$ , just after the event has occurred. It is shown in [13] that the jump conditions for the sensitivities  $x_{x_0}$  are given by

$$x_{x_0}(\tau^+) = h_x^* x_{x_0}(\tau^-) - (f^+ - h_x^* f^-) \tau_{x_0} \quad (25)$$

where

$$\begin{aligned} h_x^* &= (h_x - h_y(g_y^-)^{-1}g_x^-)|_{\tau^-} \\ \tau_{x_0} &= -\frac{(s_x - s_y(g_y^-)^{-1}g_x^-)|_{\tau^-} x_{x_0}(\tau^-)}{(s_x - s_y(g_y^-)^{-1}g_x^-)|_{\tau^-} f^-} \\ f^- &= f(x(\tau^-), y(\tau^-)) \\ f^+ &= f(x(\tau^+), y(\tau^+)). \end{aligned}$$

The sensitivities  $y_{x_0}$  immediately after the event are given by

$$y_{x_0}(\tau^+) = -(g_y^+(\tau^+))^{-1} g_x^+(\tau^+) x_{x_0}(\tau^+).$$

Following the event, i.e., for  $t > \tau^+$ , calculation of the sensitivities proceeds according to (20),(21), until the next event is encountered. The jump conditions provide the initial conditions for the post-event calculations.

## II. EFFICIENT TRAJECTORY SENSITIVITY COMPUTATION

Consider the DAIS model (2)-(3) away from events. The trapezoidal approach to numerical integration approximates the differential equations (2) by a set of algebraic difference equations. These algebraic equations are coupled with the original algebraic equations (3) giving

$$x^{k+1} = x^k + \frac{\eta}{2} (f(x^k, y^k) + f(x^{k+1}, y^{k+1})) \quad (26)$$

$$0 = g(x^{k+1}, y^{k+1}) \quad (27)$$

where the superscripts  $k, k+1$  index the time instants  $t_k, t_{k+1}$  respectively, and  $\eta = t_{k+1} - t_k$  is the integration

time step. Equations (26)-(27) describe the evolution of the states  $x, y$  from time instant  $t_k$  to the next time instant  $t_{k+1}$ .

Notice that (26)-(27) form a set of implicit nonlinear algebraic equations. To solve for  $x^{k+1}, y^{k+1}$  given  $x^k, y^k$  requires the use of a nonlinear equation solver. Newton-based iterative techniques are commonly used. The solution process involves forming and factorizing the Jacobian

$$F_x = \begin{bmatrix} \frac{\eta}{2} f_x - I & \frac{\eta}{2} f_y \\ g_x & g_y \end{bmatrix}. \quad (28)$$

Now consider the sensitivity equations (20)-(21). Using trapezoidal integration, they are approximated by

$$\begin{aligned} x_{x_0}^{k+1} &= x_{x_0}^k + \frac{\eta}{2} (f_x^k x_{x_0}^k + f_y^k y_{x_0}^k + f_x^{k+1} x_{x_0}^{k+1} + f_y^{k+1} y_{x_0}^{k+1}) \\ 0 &= g_x^{k+1} x_{x_0}^{k+1} + g_y^{k+1} y_{x_0}^{k+1}. \end{aligned}$$

Rearranging gives

$$\begin{aligned} \begin{bmatrix} \frac{\eta}{2} f_x^{k+1} - I & \frac{\eta}{2} f_y^{k+1} \\ g_x^{k+1} & g_y^{k+1} \end{bmatrix} \begin{bmatrix} x_{x_0}^{k+1} \\ y_{x_0}^{k+1} \end{bmatrix} \\ = \begin{bmatrix} -\frac{\eta}{2} (f_x^k x_{x_0}^k + f_y^k y_{x_0}^k) - x_{x_0}^k \\ 0 \end{bmatrix}. \end{aligned} \quad (29)$$

Therefore  $x_{x_0}^{k+1}$  and  $y_{x_0}^{k+1}$  are obtained as the solution of a linear matrix equation. But notice that the matrix which is inverted in solving (29) is exactly the Jacobian (28) used in solving for  $x^{k+1}$  and  $y^{k+1}$ . Because that matrix has already been built and factorized to calculate  $x^{k+1}$  and  $y^{k+1}$ , the solution of (29) involves little extra computation.

To improve simulation speed, (26)-(27) are often solved using a quasi-Newton method. As a result, the factors of  $F_x$  may not be available for solving (29) directly. However a number of computationally efficient techniques have been proposed in [42], [43], [44].

## Local Parameterization Based Tracing for Stability Boundary, Optimal Margin Control and Time Domain Simulation

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**Abstract:** This paper is divided into three major parts. In part I, a unified framework to identify and trace voltage as well as oscillatory stability margin boundary is presented. The system load margin is traced for any control configuration. Part II proposes an optimal margin boundary tracing. It provides an optimal control configuration for a given voltage stability margin. Finally, part III provides a manifold based time domain simulation to simulate the power system dynamics modeled by differential and algebraic equations (DAE). The time domain simulation proposed here avoids ill conditioning associated with the singularity of DAE. Determination of time step size by variation rate of the dynamics makes the integration computationally efficient for multi-time scale dynamics.

**Keywords:** Voltage stability, load margin, manifold, saddle node bifurcation, Hopf bifurcation, margin boundary tracing, DAE, time domain simulation

### 1. Introduction

Voltage collapse and oscillatory instability are inherently nonlinear phenomena that relate to bifurcation from the viewpoint of nonlinear dynamic systems. Substantial research has been conducted to help understand and analyze the mechanism of those types of instability based on bifurcation theory [1-8,13].

Voltage collapse is related to Saddle Node Bifurcation (SNB); system equilibrium disappears as system parameters, mostly system load, change slowly.

Oscillatory instability is another constraint to power system operational security. Oscillatory stability is related to Hopf bifurcations [38]. Improper tuning of generation control parameters may lead to Hopf bifurcation [24,32,35]. Nonlinear load may also lead to Hopf bifurcation [12]. References [6,33,34] present an analysis related to 1992 disturbance on the midwestern segment of the US interconnected power system and the resulting oscillations caused by line tripping. It confirms that the event was indeed related to a Hopf bifurcation.

Continuation based approaches have been proposed to identify these critical points [9,10,14,15,16,21,22]. Load margin is a reasonable measure of proximity to the bifurcation related instability. It is defined as the amount of additional load on a

specified pattern of load increase that would cause power system instability. This margin can be obtained in a variety of ways. The trivial way to obtain a new margin is to retrace the PV curve for given contingency and scenario. Obviously this method is time consuming and less informative. References [23,26,25,11,46,47] focused on Saddle node bifurcation related to voltage stability margin estimation based on linear or quadratic margin sensitivities. Retracing of the entire PV curve for each parameter change is avoided. In [24] sensitivity of Hopf bifurcation for various power system parameters is studied. Margin sensitivity based methods are very useful for a quick calculation of the margin for a given change in any parameter. But the prominent sources of inaccuracy inherently associated with margin sensitivity methods make a significant impact on the reliability of the margin estimation. Parameter change, sometimes due to a contingency may not be within a small range and hence higher non-linearity could not be neglected [21].

In the first part, this paper presents a framework based on differential manifold approach [36,40] that combines identification and tracing of both saddle node and Hopf bifurcation margin boundaries without calculating any eigenvalues. For a given base case, we first identify either saddle node or Hopf bifurcation. Then for any given control change scenario, we can further trace the change in Saddle node or Hopf bifurcation margins. Fig. 1-1 shows the conceptual diagram of margin boundary tracing.

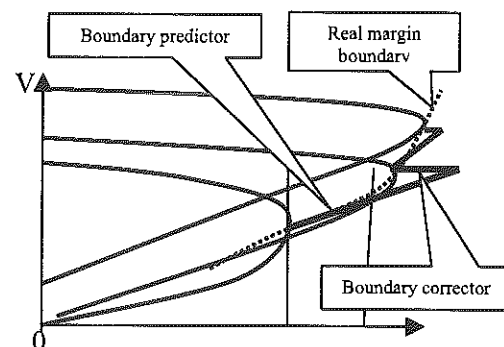


Figure 1-1: Illustration of margin boundary tracing framework

In part I of this paper we are interested only in tracing either voltage or oscillatory stability margin for a given control scenario. In the second part, we also take into account the cost of control to get a given amount of margin. Galiana group published a series of papers [27-31] on the optimal power flow based on the homotopy type continuation method. It could trace its optimal solution along a certain system scenario with optimization formulated with power flow equations. However the algorithm may diverge when the load margin associated with optimized control is close to the sequentially specified load level. Optimal margin boundary tracing proposed in this paper avoids this divergence. Fig. 1-2 shows conceptual diagram of the optimal margin boundary tracing proposed in this paper.

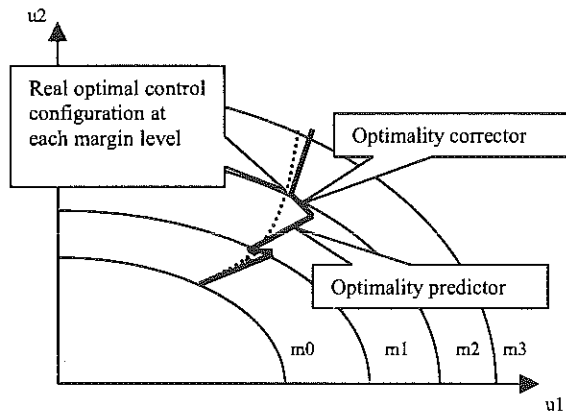


Figure 1-2: optimal margin boundary tracing

The time horizon for voltage instability dynamics varies from seconds to minutes [3]. Thus the transient stability and long term stability analysis have to be combined into a single program. In recent years, a large effort has been spent in this direction [41-45]. The stiff problem is solved by the use of variable step size and variable order integration algorithms. In part III, we propose a numerically well-conditioned manifold-continuation based time domain simulation to solve power system DAE's. It can also approximate the quasi-steady state simulation [17,18,19,20].

In this paper, we present a comprehensive methodology that combines margin boundary tracing, optimization and time domain simulation. The basic power system modeling for this formulation is presented in section 2. Section 3 provides a unified voltage and oscillatory stability margin boundary tracing framework. Section 4 describes the optimal margin control tracing. Section 5 introduces the manifold based time domain simulation. Finally section 6 provides the numerical results.

## 2. Power System Modeling

A power system is assumed to have  $n$  buses and  $m$  generators. Each generator is assumed to be equipped with the same type

of excitation control system and speed governor. The power system can be mathematically formulated as follows. The commonly used power system notations are adopted here.

### 2.1 Synchronous Generator

Without loss of generality, the rotor angle of the  $m$ -th generator is chosen as the system angle reference. This choice of reference is different from the conventional slack bus selection. No assumptions are necessary for choosing such a reference. When stator transients are ignored, the two-axis model [4,48] describing the synchronous machine dynamics can be given as:

$$\delta_i = (\omega_i - \omega_m)\omega_0 \quad i=1, \dots, m-1 \quad (2.1)$$

$$\omega_i = M_i^{-1} [P_{mi} - D_i(\omega_i - \omega_m) - (E_{qi}' - X_{di}'I_{di})I_{qi}' - (E_{di}' + X_{qi}'I_{qi}')I_{di}'] \quad i=1, \dots, m \quad (2.2)$$

$$E_{qi}' = T_{d0i}^{-1} [E_{fdi} - E_{qi}' - (X_{di}' - X_{di}')I_{di}'] \quad i=1, \dots, m \quad (2.3)$$

$$E_{di}' = T_{q0i}^{-1} [-E_{di}' + (X_{qi}' - X_{qi}')I_{qi}'] \quad i=1, \dots, m \quad (2.4)$$

where  $\omega_m$  is the system frequency,  $\omega_i$  is the machine frequency, namely, generator angular speed and  $\omega_0$  is the system rated frequency (377.0 rad/sec).  $I_{di}$  and  $I_{qi}$  are direct axis and quadrature axis currents respectively,  $E_{di}'$  and  $E_{qi}'$  are transient direct axis and quadrature axis EMF respectively,  $T_{d0i}$  and  $T_{q0i}$  are direct axis and quadrature axis open circuit time constants respectively,  $X_{di}'$  and  $X_{qi}'$  are direct axis and quadrature axis transient reactances and  $R_{si}$  are armature resistance of the machine.  $M_i$  is inertia constant and  $D_i$  is the damping constant of the machine. All the quantities are in per unit except  $\omega_0$ .

Interface voltage equations to the network is given as follows:

$$E_{qi}' = V_i \cos(\delta_i - \theta_i) + R_{si}I_{qi}' + X_{di}'I_{di}' \quad (2.5)$$

$$E_{di}' = V_i \sin(\delta_i - \theta_i) + R_{si}I_{di}' - X_{qi}'I_{qi}' \quad (2.6)$$

Where  $V_i$  and  $\theta_i$  are bus voltage and angle respectively.

The machine currents  $I_{di}$  and  $I_{qi}$  can be eliminated by solving the generator interface equations to the network. Hence,

$$I_{di}' = [R_{si}E_{di}' + E_{qi}'X_{qi}' - R_{si}V_i \sin(\delta_i - \theta_i) - X_{di}'V_i \cos(\delta_i - \theta_i)]A_i^{-1} \quad (2.7)$$

$$I_{qi}' = [R_{si}E_{qi}' - E_{di}'X_{di}' - R_{si}V_i \cos(\delta_i - \theta_i) - X_{qi}'V_i \sin(\delta_i - \theta_i)]A_i^{-1} \quad (2.8)$$

$$A_i = R_{si}^2 + X_{di}'X_{qi}' \quad (2.9)$$

Note that (2.1) does not include the differential equation for  $\delta_m$ , and all the angles here and henceforth are relative angles with respect to the  $m$ -th generator's rotor angle.

### 2.2 Excitation Control System

The simplified IEEE type DC-1 excitation system [4] as shown in Figure 2-1 is used here. The corresponding mathematical model is

$$E_{fdi} = T_{ei}^{-1} [V_{ri} - [S_{ei}(E_{fdi})]E_{fdi}] \quad i = 1, \dots, m \quad (2.10)$$

$$V_{ri} = T_{ai}^{-1} [-V_{ri} + K_{ai}(V_{refi} - V_i - R_{\beta})] \quad i = 1, \dots, m \quad (2.11)$$

If

$$V_{ri, \min} \leq V_{ri} \leq V_{ri, \max}, \quad V_{psi} = 0 \quad (\text{at steady state})$$

$$R_{\beta} = T_{\beta}^{-1} [-R_{\beta} - [K_{ei} + S_{ei}(E_{fdi})]K_{\beta}E_{fdi} / T_{ei} + K_{\beta}V_{ri} / T_{ei}] \quad i = 1, \dots, m \quad (2.12)$$

Here  $V_{refi}$  is the reference voltage of the automatic voltage regulator (AVR);  $V_{ri}$  and  $R_{\beta}$  are the outputs of the AVR and exciter soft feedback;  $E_{fdi}$  is the voltage applied to generator field winding;  $T_{ai}$ ,  $T_{ei}$  and  $T_{\beta}$  are AVR, exciter and feedback time constants;  $K_{ai}$ ,  $K_{ei}$  and  $K_{\beta}$  are gains of AVR, exciter and feedback;  $V_{ri, \min}$  and  $V_{ri, \max}$  are the lower and upper limits of  $V_{ri}$ .

### 2.3 Prime Mover and Speed Governor

Figure 2-2 shows the block diagram for a simplified prime mover and speed governor. Two differential equations are involved to describe the dynamics when no  $\mu_i$  limit is hit.

$$P_{mi} = T_{chi}^{-1} (\mu_i - P_{mi}) \quad i = 1, \dots, m \quad (2.13)$$

$$\mu_i = T_{gi}^{-1} [P_{gsi} - (\omega_i - \omega_{ref}) / R_i - \mu_i] \quad \text{if } \mu_{i, \min} \leq \mu_i \leq \mu_{i, \max} \quad i = 1, \dots, m \quad (2.14)$$

Where  $P_{gsi} = P_{gsi}^0 (1 + K_{gi}\alpha)$  is the designated real power generation;  $P_{gsi}^0$  is its setting at base case;  $K_{gi}$  is the generator load picking-up factor that could be determined by AGC, EDC or other system operating practice;

$P_{mi}$  is the mechanical power of prime mover and  $\mu_i$  is the steam valve or water gate opening;  $R_i$  is the governor regulation constant representing its inherent speed-droop characteristic;  $\omega_{ref}$  ( $=1.0$ ) is the governor reference speed;

$T_{chi}$  and  $T_{gi}$  are the time constants related to the prime mover and speed governor respectively;  $\mu_{i, \min}$  and  $\mu_{i, \max}$  are the lower and upper limits of  $\mu$ . Here a parameter  $\alpha$  is introduced to designate the system operation scenario. At base case,  $\alpha$  equals to zero.

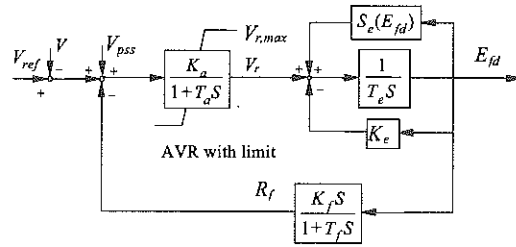


Figure 2-1 The IEEE type DC-1 excitation system

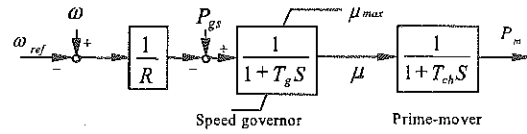


Figure 2-2 The simplified speed governor and prime mover

### 2.4 Nonlinear Load Model

The voltage and frequency dependent load model is used for all the load buses.

$$\begin{cases} P_{li} = P_{li0} (V_i / V_{i0})^{\alpha_i} [1 + K_{lpf}(\omega_m - \omega_r)] \\ Q_{li} = Q_{li0} (V_i / V_{i0})^{\beta_i} [1 + K_{lqf}(\omega_m - \omega_r)] \end{cases} \quad i = 1, \dots, m \quad (2.15)$$

Where  $P_{li0}$  and  $Q_{li0}$  are the powers absorbed by the load at the nominal voltage  $V_i$  and frequency  $\omega_r$  ( $=1.0$ ). The frequency dependent term is included to prevent the equilibrium computation from divergence in case all the generators reach their maximum real power limits due to load increase or generator outages. Here  $K_{lpf}$  and  $K_{lqf}$  are the load changing factors with respect to system frequency.

### 2.5 Network Power Equations

Corresponding to the above models, the network equations can be written as:

$$\begin{cases} 0 = P_{gi} - P_{li} - P_{ti} \\ 0 = Q_{gi} - Q_{li} - Q_{ti} \end{cases} \quad i = 1, \dots, n \quad (2.16)$$

Where

$$\begin{cases} P_{ti} = \sum_{k=1}^n V_i V_k Y_{ik} \cos(\theta_i - \theta_k - \phi_{ik}) \\ Q_{ti} = \sum_{k=1}^n V_i V_k Y_{ik} \sin(\theta_i - \theta_k - \phi_{ik}) \end{cases} \quad i = 1, \dots, n \quad (2.17)$$

and

$$\begin{cases} P_{gi} = I_{di} V_i \sin(\delta_i - \theta_i) + I_{qi} V_i \cos(\delta_i - \theta_i) \\ Q_{gi} = I_{di} V_i \cos(\delta_i - \theta_i) - I_{qi} V_i \sin(\delta_i - \theta_i) \end{cases} \quad i = 1, \dots, m \quad (2.18)$$

$P_{gi}$  and  $Q_{gi}$  are the generator output powers, which are primarily determined by the inherent characteristics of the speed governor and the AVR regulations. They will change if real power generation rescheduling and secondary voltage control are applied.  $P_{ii}$  and  $Q_{ii}$  are the powers injected into the network at bus  $i$ .

## 2.6 Power System DAE Model

The differential together with algebraic equations are commonly known as a DAE representation of the power system. They can be simply denoted as

$$\begin{cases} \dot{X} = F^0(X, Y, Z, U) \\ 0 = G^0(X, Y, Z, U) \end{cases} \quad X(t_0) = X_0 \quad (2.19)$$

$X$  contains all the system state variables;  $Y$  includes the algebraic variables;  $U$  is the control vector whereas  $Z$  consists of all uncontrolled disturbance, e.g. load variation at each bus.

The effects of on-load tap changer are approximately taken into account in (2.19) by adjusting their tap ratios during equilibrium tracing. It should be pointed out that although other dynamic devices such as HVDC and FACTS are not explicitly formulated here, they could be easily included in (2.19).

## 3. Unified Voltage and Oscillatory Stability Boundary Tracing

### 3.1 Formulation of Unified Margin Boundary Tracing

#### 3.1.1 Margin Boundary Manifold

In the case of a multi-dimensional, implicitly defined manifold  $M$ , specific local parameterization needs to be constructed to trace a certain sub-manifold with special property on  $M$ . Saddle node or Hopf bifurcation point forms a margin boundary sub-manifold corresponding to the change of control parameters along a specified control scenario. Therefore bifurcation related stability margin boundary could be traced by specific design of local parameterization.

#### 3.2.2 Natural Parameterization for Margin Boundary Tracing

From (2.19), the equilibrium manifold of power system is defined by

$$\begin{cases} 0 = F^0(X, Y, Z, U) \\ 0 = G^0(X, Y, Z, U) \end{cases} \quad (3.1)$$

The solution set of above nonlinear equation system constructs a manifold, which could be parameterized by control parameters and disturbance parameters. Both  $X$  and  $Y$  indicate the state of the system, so they could be combined as state space. The parameter space is the combination of control parameters  $U$  and load parameters  $Z$ . There is a natural splitting in parameter space:

parameter space = control parameter space  $\oplus$  load parameter space

#### Load Parameter space

Based on loading scenario, the loading parameter space could be parameterized by scalar  $\mu$  to characterize the system loading pattern.

$$\begin{cases} P_{ii} = (1 + K_{lpi}\mu)P_{ii0} \\ Q_{ii} = (1 + K_{lqi}\mu)Q_{ii0} \end{cases} \quad (3.2)$$

where  $P_{ii0}$  and  $Q_{ii0}$  represent the initial loading conditions at base case where  $\mu$  is assumed to be zero.  $K_{lpi}$  and  $K_{lqi}$  indicates the rate of load change at bus  $i$  as  $\mu$  changes.

Correspondingly, a specified generation scenario is given as follows,

$$P_{gi} = (1 + K_{gli}\mu)P_{gi0} \quad (3.3)$$

, where  $P_{gi0}$  is the active generation at bus  $i$  in the base case and  $K_{gli}$  is the generator load picking-up factor that could be determined by AGC, EDC or other system operating practice.

#### Control Parameter Space

Control parameter space contains every type of control. The following controls are studied in this paper:

- Shed loads
- Shunt capacitance
- Shunt reactive power compensation
- Generator secondly voltage control

Control parameter space, is parameterized by a scalar  $\alpha$  to characterize this space.

$$U_i = U_{i0} + \alpha L_i \quad (3.4)$$

Where  $U_{i0}$  indicates the initial configuration of control  $i$ .

Different combinations of control actions can be achieved by assigning different ratio value to  $L_i$ .

This parameterization leads to two parameter variations:  $\mu$  characterizing system loading condition with respect to a specified loading scenario and  $\alpha$  characterizing control parameter with respect to a specified control scenario. The equations of power system are reduced to

$$\begin{cases} 0 = F(X, Y, \mu, \alpha) \\ 0 = G(X, Y, \mu, \alpha) \end{cases} \quad (3.5)$$

#### 3.2.3 Equilibrium Tracing with Bifurcation Identification

With fixed control, direct equilibrium tracing method [10] is applied from the base case point until it reaches the bifurcation point, which is further used as initial point for margin boundary tracing. Along the tracing, both Saddle node and Hopf bifurcations are identified without eigenvalue calculation.

#### Identification of Saddle node bifurcation

Saddle node bifurcation of the above DAE system corresponds to fold bifurcation of (3.5). In ref [40], an implicitly defined cut function  $\gamma_{SNB}$  is proposed that identifies the fold points.

$$\text{Accordingly, } \begin{bmatrix} F_X & F_Y & e_k \\ G_X & G_Y & 0 \\ e_j^T & 0 & \gamma_{SNB} \end{bmatrix} \begin{bmatrix} u_X \\ u_Y \\ 1 \end{bmatrix} + \begin{bmatrix} 0 \\ 0 \\ 1 \end{bmatrix} = 0 \quad (3.6)$$

$$\text{or equivalently, } \begin{bmatrix} F_X & F_Y & e_k \\ G_X & G_Y & 0 \\ e_j^T & 0 & \gamma_{SNB} \end{bmatrix}^T \begin{bmatrix} v_X \\ v_Y \\ 1 \end{bmatrix} + \begin{bmatrix} 0 \\ 0 \\ 1 \end{bmatrix} = 0 \quad (3.7)$$

At the fold point, the cut set condition as defined in [40] is satisfied, that is  $\gamma_{SNB}(X, Y, \mu, \alpha) = 0$ .

At each continuation step,  $\gamma_{SNB}$  is checked. If  $\gamma_{SNB}$  changes sign, Saddle node bifurcation has just been passed.

Derivative of the augmenting function  $\gamma_{SNB}$  is needed in further tracing SNB related margin boundary. Differentiation of above augmented equations leads to [40]

$$D\gamma_{SNB}w = v^T D \begin{bmatrix} F_X & F_Y \\ G_X & G_Y \end{bmatrix} (u, w) \quad (3.8)$$

$$\text{where } w = \begin{bmatrix} dX \\ dY \\ d\mu \\ d\alpha \end{bmatrix}, \quad u = \begin{bmatrix} u_X \\ u_Y \end{bmatrix}, \quad v = \begin{bmatrix} v_X \\ v_Y \end{bmatrix}$$

In implementation, finite differentiation is applied instead as follows [40].

$$D\gamma_{SNB} \approx \frac{1}{\delta} v_{\delta}^{0T} \gamma_{\delta} \left[ T_{(X+\delta u_X, Y+\delta u_Y, \mu, \alpha)} - T_{(X, Y, \mu, \alpha)} \right] \quad (3.9)$$

Where the test matrix for SNB is defined as

$$T = \begin{bmatrix} DF \\ DG \end{bmatrix}$$

### Identification of Hopf Bifurcation

Similar approach based on cut function for Saddle node bifurcation is extended to locate Hopf bifurcation.

Let

$$A_{total} = \begin{bmatrix} F_X & F_Y \\ G_X & G_Y \end{bmatrix}, \quad A_{sys} = F_X - F_Y G_Y^{-1} G_X$$

The following propositions lead to quick detection of Hopf bifurcation.

$$\text{Proposition 1: If } A_{sys} u_X = \lambda u_X \quad (3.10)$$

$$\text{then there exist } u_Y = -G_Y^{-1} G_X u_X \quad (3.11)$$

if and only if

$$\begin{bmatrix} F_X - \lambda I & F_Y \\ G_X & G_Y \end{bmatrix} \begin{bmatrix} u_X \\ u_Y \end{bmatrix} = 0 \quad (3.12)$$

We define the extended eigenvector  $u = \begin{bmatrix} u_X^T & u_Y^T \end{bmatrix}^T$ .

This proposition has been proved in Ref [11].

**Proposition 2:** Let the maximum eigenvalue of  $(A_{total} + A_{total}^T) = \begin{bmatrix} F_X + F_X^T & F_Y + G_X^T \\ G_X + F_Y^T & G_Y + G_Y^T \end{bmatrix}$  is  $\lambda_1$ , then  $\lambda_1 \geq 0$  is the necessary condition of Hopf bifurcation associated with power system DAE model  $(A_{sys})$ . When  $A_{total}$  is approximate to normal matrix (this is the most likely case),  $\lambda_1 = 0$  becomes the necessary condition;

*Proof:*

1) At Hopf bifurcation, there exists an eigenvalue of  $A_{sys}$ ,  $\lambda = j\omega$  such that, from proposition 1

$$(A_{total} - j\omega \begin{bmatrix} I & 0 \\ 0 & 0 \end{bmatrix}) u = \begin{bmatrix} F_X - j\omega & F_Y \\ G_X & G_Y \end{bmatrix} u = 0 \text{ and } u \text{ is an}$$

associated eigenvector with 2-norm unity. Then

$$0 = ((A_{total} - j\omega \begin{bmatrix} I & 0 \\ 0 & 0 \end{bmatrix}) u, u) = u^H (A_{total} - j\omega \begin{bmatrix} I & 0 \\ 0 & 0 \end{bmatrix}) u \text{ and,}$$

$$0 = u^H (A_{total} - j\omega \begin{bmatrix} I & 0 \\ 0 & 0 \end{bmatrix})^H u = ((A_{total}^T + j\omega \begin{bmatrix} I & 0 \\ 0 & 0 \end{bmatrix}) u, u)$$

Therefore,  $0 = ((A_{total} + A_{total}^T) u, u)$ . It is obtained from the summation of above two equations.

Since  $\lambda_1 = \max((A_{total} + A_{total}^T)x, x)$  for  $x \neq 0, x \in C$ ,

$$\lambda_1 \geq ((A_{total} + A_{total}^T) u, u) = 0$$

2) When  $A_{total}$  is approximate to normal matrix (this case is most likely), from Hausdorff's convex hull theorem [37],

$$((A_{total} + A_{total}^T) u, u) = \sum_{k=1}^{M+N} \beta_k \lambda_k = 0$$

with  $0 \leq \beta_k \leq 1$  and  $\sum_{k=1}^{M+N} \beta_k = 1$  Where M is dimension of

dynamic variable and N is the dimension of algebraic variable.

For a normal operation of power system,  $A_{total} \lambda_k \leq 0$

Therefore  $\lambda_1 = 0$ .

Then the identification of Hopf bifurcation for  $A_{sys}$  is nothing but to find the singularity of the matrix  $(A_{total} + A_{total}^T)$ . A set of cut functions  $\gamma_{H1}(x)$  and  $\gamma_{H2}(x)$  can be used to find the Hopf related fold bifurcation as described below.

$$\begin{bmatrix} F_X + F_X^T & F_Y + G_X^T & e_k & e_j \\ G_X + F_Y^T & G_Y + G_Y^T & 0 & 0 \\ e_k^T & 0 & 0 & \gamma_{H1} \\ e_j^T & 0 & 0 & \gamma_{H2} \end{bmatrix} \begin{bmatrix} u_X \\ u_Y \\ 1 \\ 1 \end{bmatrix} + \begin{bmatrix} 0 \\ 0 \\ 1 \\ 1 \end{bmatrix} = 0 \quad (3.13)$$

where  $k \neq j$  or equivalently,

$$\begin{bmatrix} F_X + F_X^T & F_Y + G_X^T & e_k & e_j \\ G_X + F_Y^T & G_Y + G_Y^T & 0 & 0 \\ e_k^T & 0 & 0 & 0 \\ e_j^T & 0 & 0 & 0 \end{bmatrix} \begin{bmatrix} v_X \\ v_Y \\ \gamma_{H1} \\ \gamma_{H2} \end{bmatrix} + \begin{bmatrix} 0 \\ 0 \\ 1 \\ 0 \end{bmatrix} = 0 \quad (3.14)$$

At the Hopf bifurcation, the cut set condition is satisfied, that is

$$\gamma_{H1}(X, Y, \mu, \alpha) = 0, \text{ and } \gamma_{H2}(X, Y, \mu, \alpha) = 0 \quad (3.15)$$

At each continuation step,  $\gamma_{SNB}$ ,  $\gamma_{H1}$ , and  $\gamma_{H2}$  are checked.

If  $\gamma_{SNB}$  changes sign, Saddle node bifurcation has just been passed.

Otherwise, if both  $\gamma_{H1}$ , and  $\gamma_{H2}$  change sign, Hopf bifurcation has just been passed.

Therefore, without eigenvalue calculation Hopf bifurcation can be detected along with Saddle node bifurcation with properly defined cut functions.

Derivative of the augmenting function  $\gamma_{H1}$  is also needed in Hopf related boundary tracing. Similar to (3.8), by differentiation of above augmented equations, it can be obtained from

$$D\gamma_{H1}w = v^T D \begin{bmatrix} F_X + F_X^T & F_Y + G_X^T \\ G_X + F_Y^T & G_Y + G_Y^T \end{bmatrix} (u, w) \quad (3.16)$$

Here also we can use finite differentiation approximation as follows.

$$D\gamma_{H1} \approx \frac{1}{\delta} v^T_{(X,Y,\mu,\alpha)} [T_{(X+\delta u_X, Y+\delta u_Y, \mu, \alpha)} - T_{(X,Y,\mu,\alpha)}] \quad (3.17)$$

Where the test matrix for Hopf bifurcation is defined as

$$T = \begin{bmatrix} DF \\ DG \end{bmatrix} + \begin{bmatrix} DF^T \\ DG^T \end{bmatrix} \quad (3.18)$$

### 3.2.4 Unified Margin Boundary Tracing

Further tracing of these bifurcations can be obtained by the solution manifold as defined in (3.19)[40].

$$B(X, Y, \mu, \alpha) = \begin{bmatrix} F(X, Y, \mu, \alpha) \\ G(X, Y, \mu, \alpha) \\ c(X, Y, \mu, \alpha) \end{bmatrix} = 0 \quad (3.19)$$

Cut function for voltage collapse (SNB related) margin boundary tracing is defined as

$$c(X, Y, \mu, \alpha) = \gamma_{SNB}(X, Y, \mu, \alpha) \quad (3.20)$$

$$Dc(X, Y, \mu, \alpha) = D\gamma_{SNB} \quad (3.21)$$

Cut function for oscillatory stability (Hopf bifurcation related) margin boundary tracing is defined as

$$c(X, Y, \mu, \alpha) = \gamma_{H1}(X, Y, \mu, \alpha) \quad (3.22)$$

$$Dc(X, Y, \mu, \alpha) = D\gamma_{H1} \quad (3.23)$$

(Here  $D$  stands for differentiation)

### Boundary predictor

The total augmented equations for margin boundary tracing are

$$H(X, Y, \mu, \alpha) = \begin{bmatrix} B(X, Y, \mu, \alpha) \\ [X^T \ Y^T \ \mu \ \alpha] e_k - \eta \end{bmatrix} = \begin{bmatrix} F(X, Y, \mu, \alpha) \\ G(X, Y, \mu, \alpha) \\ c(X, Y, \mu, \alpha) \\ [X^T \ Y^T \ \mu \ \alpha] e_k - \eta \end{bmatrix} \quad (3.24)$$

$$DH(X, Y, \mu, \alpha) = \begin{bmatrix} DF \\ DG \\ Dc \\ e_k^T \end{bmatrix} \quad (3.25)$$

Where  $\eta = [X_{pre}^T \ Y_{pre}^T \ \mu_{pre} \ \alpha_{pre}] e_k$  and is obtained from the tangent vector calculated in boundary predictor. With  $\delta$  as step size,

$$DH(X, Y, \mu, \alpha) \begin{bmatrix} dX \\ dY \\ d\mu \\ d\alpha \end{bmatrix} = \begin{bmatrix} 0 \\ 0 \\ 0 \\ \pm 1 \end{bmatrix} \text{ and } \begin{bmatrix} X_{pre} \\ Y_{pre} \\ \mu_{pre} \\ \alpha_{pre} \end{bmatrix} = \begin{bmatrix} X \\ Y \\ \mu \\ \alpha \end{bmatrix} + \delta \begin{bmatrix} dX \\ dY \\ d\mu \\ d\alpha \end{bmatrix} \quad (3.26)$$

The Jacobian matrix of the augmented equation system is nonsingular with properly chosen continuation parameter.

### Boundary corrector

Newton method is employed to do the boundary correction as

$$\begin{bmatrix} X \\ Y \\ \mu \\ \alpha \end{bmatrix}^{new} = \begin{bmatrix} X \\ Y \\ \mu \\ \alpha \end{bmatrix} - DH^{-1}(X, Y, \mu, \alpha) H(X, Y, \mu, \alpha) \quad (3.27)$$

### 3.3 Unified Margin Boundary Tracing Procedure

The program can check either SNB or Hopf bifurcation condition along the equilibrium tracing and further trace any related margin boundary. It also could check both bifurcation conditions and always switch to and continue the tracing on the most conservative margin boundary. The following steps are involved in unified margin boundary tracing.

- 1) Specify a loading scenario.
- 2) Direct Equilibrium Tracing starts at current operating point for the first boundary point under current fixed control configuration and specified loading scenario.
- 3) Specify the control scenario that describes the change of control configuration or contingencies.
- 4) Boundary Prediction with (3.26)
- 5) Boundary Correction with (3.27)
- 6) Go to 4) unless some control variables hit limits, else stop.

### 4. Optimal Margin Boundary Tracing (OMBT) with Continuation Optimal Power Flow (COPF)

In the previous section, the direction of control vector is arbitrarily chosen. In this section, the control vector is selected based on the cost criteria. Local parameterization based

optimal power flow is proposed here. We restrict the optimization analysis to voltage stability margin. It is formulated as follows.

#### 4.1 Problem Formulation

For a sequence of required margin  $P_{m\lambda}$ ,

$$\begin{aligned} & \min f(U) \\ & \text{s. t.} \\ & \begin{cases} F(X, Y, \mu, U) = 0 \\ G(X, Y, \mu, U) = 0 \\ h(X, Y, \mu, U) \leq 0 \end{cases} \end{aligned} \quad (4.1)$$

$\mu$  is the loading parameter directly associated with  $P_{m\lambda}$ , which is the margin to be maintained.  $f(U)$  is the cost function representing the total control cost to be minimized.  $U$  is the selected control variables.

Margin boundary forms a multi-dimensional, implicitly defined manifold in multi-control parameter space. Specific local parameterization needs to be constructed to trace a certain sub-manifold with special property on margin boundary manifold. The optimal control configuration for a given load margin is of special interest on the manifold. Optimal margin boundary manifold could be traced by augmenting the original equilibrium equations with optimality conditions.

The Lagrangian [39] of the optimal parameterized margin boundary problem is

$$L(X, Y, \mu, U) = f(U) + \lambda_F^T F(X, Y, \mu, U) + \lambda_G^T G(X, Y, \mu, U) + s^T h(X, Y, \mu, U) \quad (4.2)$$

Where  $[\lambda_F^T \ \lambda_G^T]$  is the multiplier vector for the equality constraints,  $s$  is the multiplier vector for the operation limit constraints of  $[X^T \ Y^T \ \mu \ U^T]^T$ .

The first order K-T optimality conditions are,

$$\begin{bmatrix} L_X \\ L_Y \\ L_U \end{bmatrix} = \begin{bmatrix} 0 \\ 0 \\ f_U \end{bmatrix} + \begin{bmatrix} F_X^T & G_X^T & h_X^T \\ F_Y^T & G_Y^T & h_Y^T \\ F_U^T & G_U^T & h_U^T \end{bmatrix} \begin{bmatrix} \lambda_F \\ \lambda_G \\ s \end{bmatrix} = 0 \quad (4.3)$$

$$h(X, Y, \mu, U)^T s = 0 \quad (4.4)$$

$$\begin{bmatrix} F(X, Y, \mu, U) \\ G(X, Y, \mu, U) \end{bmatrix} = 0 \quad (4.5)$$

#### 4.2 Initialization of Optimal Margin Boundary Tracing

Before tracing for optimal margin control submanifold on the power system equilibrium manifold, the initial margin is achieved by direct equilibrium tracing. The continuation optimal power flow can trace the optimal control to extend the margin.

#### 4.3 Continuation Optimal Power Flow

##### Optimality Predictor

At the boundary predictor stage, optimal tangent vector is sought with the optimization problem formulated in the tangent space which locally approximates the margin boundary manifold.

With the augmented Jacobian of the first order optimality conditions (4.3) to (4.5), the optimality predictor is

$$\begin{bmatrix} F_X & F_Y & F_\mu & F_U & 0 & 0 & 0 \\ G_X & G_Y & G_\mu & G_U & 0 & 0 & 0 \\ h_{AX} & h_{AY} & h_{A\mu} & h_{AU} & 0 & 0 & 0 \\ L_{XX} & L_{XY} & L_{X\mu} & L_{XU} & F_X^T & G_X^T & h_{AX}^T \\ L_{YX} & L_{YY} & L_{Y\mu} & L_{YU} & F_Y^T & G_Y^T & h_{AY}^T \\ L_{UX} & L_{UY} & L_{U\mu} & L_{UU} & F_U^T & G_U^T & h_{AU}^T \\ e_k \end{bmatrix} \begin{bmatrix} dX \\ dY \\ d\mu \\ dU \\ d\lambda_F \\ d\lambda_G \\ ds \end{bmatrix}^{opt} = \begin{bmatrix} 0 \\ 0 \\ 0 \\ 0 \\ 0 \\ 0 \\ \pm 1 \end{bmatrix} \quad (4.6)$$

The optimality tangent vector is defined as

$$t^{opt} = [dX^T \ dY^T \ d\mu \ dU^T \ d\lambda_F^T \ d\lambda_G^T \ ds^T]^{opt}$$

Then the predicted optimal margin control solution is obtained by

$$\begin{bmatrix} X \\ Y \\ \mu \\ U \\ \lambda_F \\ \lambda_G \\ s \end{bmatrix}^{i+1} = \begin{bmatrix} X \\ Y \\ \mu \\ U \\ \lambda_F \\ \lambda_G \\ s \end{bmatrix}^i + \delta \begin{bmatrix} dX \\ dY \\ d\mu \\ dU \\ d\lambda_F \\ d\lambda_G \\ ds \end{bmatrix}^{opt} \quad (4.7)$$

##### Optimality corrector

The optimality corrector brings the optimal margin control solution back to optimal margin control manifold.

$$\begin{bmatrix} F_X & F_Y & F_\mu & F_U & 0 & 0 & 0 \\ G_X & G_Y & G_\mu & G_U & 0 & 0 & 0 \\ h_{AX} & h_{AY} & h_{A\mu} & h_{AU} & 0 & 0 & 0 \\ L_{XX} & L_{XY} & L_{X\mu} & L_{XU} & F_X^T & G_X^T & h_{AX}^T \\ L_{YX} & L_{YY} & L_{Y\mu} & L_{YU} & F_Y^T & G_Y^T & h_{AY}^T \\ L_{UX} & L_{UY} & L_{U\mu} & L_{UU} & F_U^T & G_U^T & h_{AU}^T \\ e_k \end{bmatrix} \begin{bmatrix} \Delta X \\ \Delta Y \\ \Delta \mu \\ \Delta U \\ \Delta \lambda_F \\ \Delta \lambda_G \\ \Delta s \end{bmatrix} = - \begin{bmatrix} F \\ G \\ h_A \\ L_X \\ L_Y \\ L_U \\ 0 \end{bmatrix} \quad (4.8)$$

##### Selection of the continuation parameter

$|t_k| = \max\{|t_1|, |t_2|, \dots, |t_{m+n+1}|\}$ , that is, to select the variable with the largest change in state variables  $X$ , algebraic variables  $Y$  or load parameter  $\mu$ .

##### Determination of the largest possible load margin

The largest possible load margin is determined by the sign change of  $d\mu$ .



#### 4.4 Optimal Margin Boundary Tracing Procedure

Steps involved in optimal margin boundary tracing.

- 1) Specify a required margin.
- 2) Identify the boundary point under current control configuration with direct equilibrium tracing.
- 3) Do optimal prediction with (4.7).
- 4) Do optimal correction with (4.8).
- 5) Go to 3) until  $d\mu$  corresponding to load parameter changes sign, which indicates the system has reached the largest possible load increase.

#### 5. Local Parameterization Based Time Domain Simulation

Local parameterization based predictor-corrector approach can also be extended to trace time domain trajectory. Local parameterization is constructed to adjust the integration step size according to the variation of derivative of dynamic variable  $\dot{X}$  or network variable  $Y$ . Numerical ill-conditioning due to  $G_Y^{-1}$  could also be avoided.

##### 5.1 Formulation of Conventional Time Domain Simulation

The power system representation for time domain simulation is given by

$$\begin{cases} \dot{X} = F^0(X, Y, Z, U) \\ 0 = G^0(X, Y, Z, U) \end{cases} \quad X(t_0) = X_0 \quad (2.19)$$

Here in general, load dynamic characteristics could be represented by general form:

$$\dot{Z} = H^0(X, Y, Z, U) \quad (5.1)$$

Given  $[X^T \ Y^T \ Z^T]^T$ , conventionally the following nonlinear equations are solved for  $[Y^{i+1} \ \dot{X}^{i+1} \ \dot{Z}^{i+1}]^T$  with specified  $t_{\Delta}^{i+1}$ .

$$\tilde{F}(Y^{i+1}, \dot{X}^{i+1}, \dot{Z}^{i+1}, t_{\Delta}^{i+1}) = F^0(X^i + \dot{X}^i t_{\Delta}^{i+1}, Y^{i+1}, Z^i + \dot{Z}^i t_{\Delta}^{i+1}, U) - \dot{X}^{i+1} = 0 \quad (5.2)$$

$$\tilde{H}(Y^{i+1}, \dot{X}^{i+1}, \dot{Z}^{i+1}, t_{\Delta}^{i+1}) = H^0(X^i + \dot{X}^i t_{\Delta}^{i+1}, Y^{i+1}, Z^i + \dot{Z}^i t_{\Delta}^{i+1}, U) - \dot{Z}^{i+1} = 0 \quad (5.3)$$

$$\tilde{G}(Y^{i+1}, \dot{X}^{i+1}, \dot{Z}^{i+1}, t_{\Delta}^{i+1}) = G^0(X^i + \dot{X}^i t_{\Delta}^{i+1}, Y^{i+1}, Z^i + \dot{Z}^i t_{\Delta}^{i+1}, U) = 0 \quad (5.4)$$

(Where, for simplicity, Euler method is employed to demonstrate the manifold based algorithm).  $X$  and  $Z$  are updated according to (5.5) and (5.6)

$$X^{i+1} = X^i + t_{\Delta}^{i+1} \dot{X}^i \quad (5.5)$$

$$Z^{i+1} = Z^i + t_{\Delta}^{i+1} \dot{Z}^i \quad (5.6)$$

#### 5.2 Formulation of Local Parameterization Based Time Domain Simulation

The solution manifold of (5.2)-(5.4) can be parameterized by  $t_{\Delta}^{i+1}$ . It forms a one dimensional manifold. Similar to equilibrium tracing, the whole time trajectory is traced by one step predictor-corrector approach on each piece of solution manifold defined by (5.2)-(5.4). The Fig. 5-1 shows the conceptual diagram.

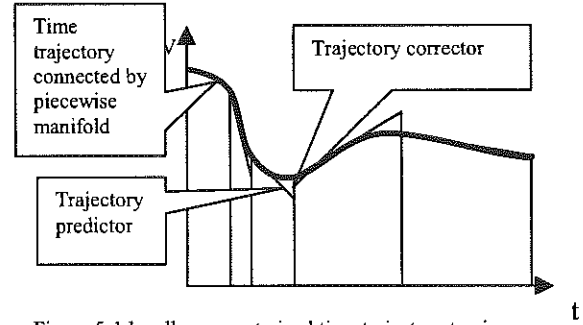


Figure 5-1 locally parameterized time trajectory tracing

##### Trajectory predictor

From the initial point, the next point can be predicted from the following equation.

$$\begin{bmatrix} F_Y^i & -I_{n_{ox}} & 0 & F_X^i \dot{X}^i + F_Z^i \dot{Z}^i \\ H_Y^i & 0 & -I_{d \times d} & H_X^i \dot{X}^i + H_Z^i \dot{Z}^i \\ G_Y^i & 0 & 0 & G_X^i \dot{X}^i + G_Z^i \dot{Z}^i \\ e_k \end{bmatrix} \begin{bmatrix} dY^{i+1} \\ d\dot{X}^{i+1} \\ d\dot{Z}^{i+1} \\ dt_{\Delta}^{i+1} \end{bmatrix} = \begin{bmatrix} 0 \\ 0 \\ 0 \\ \pm 1 \end{bmatrix} \quad (5.7)$$

Then the predicted solution is

$$\begin{bmatrix} Y \\ \dot{X} \\ \dot{Z} \\ t_{\Delta} \end{bmatrix}^{i+1} = \begin{bmatrix} Y \\ \dot{X} \\ \dot{Z} \\ t_{\Delta} \end{bmatrix}^i + \delta \begin{bmatrix} dY \\ d\dot{X} \\ d\dot{Z} \\ dt_{\Delta} \end{bmatrix} \quad (5.8)$$

##### Continuation parameter selection

The variable with largest variation among  $[Y^T \ \dot{X}^T \ \dot{Z}^T \ t_{\Delta}]^T$  is selected as continuation parameter.

##### Time step size adjusted according to variation of $\dot{X}$ or $Y$

For example, if the ratio of  $d\dot{X}_i$  to  $t_{\Delta}$  is the largest, then  $\dot{X}_i$  will be chosen as the continuation parameter.  $t_{\Delta}$  will be calculated such that each step change of  $\dot{X}_i$  will not be missed. If  $d\dot{X}_i$  is quite large, which indicates fast dynamics, smaller  $t_{\Delta}$  is obtained. If  $d\dot{X}_i$  is small, which indicates slow dynamics, larger  $t_{\Delta}$  is obtained comparable to step size of continuation power flow. Therefore number of integration steps is dramatically reduced for slow dynamics.

### Trajectory corrector

Newton method serves as the trajectory corrector.

$$\begin{bmatrix} F_Y^0 & -I_{mot} & 0 & F_X^0 \dot{X}^i + F_Z^0 \dot{Z}^i \\ H_Y^0 & 0 & -I_{dxd} & H_X^0 \dot{X}^i + H_Z^0 \dot{Z}^i \\ G_Y^0 & 0 & 0 & G_X^0 \dot{X}^i + G_Z^0 \dot{Z}^i \\ e_k \end{bmatrix} \begin{bmatrix} \Delta Y^{i+1} \\ \Delta X^{i+1} \\ \Delta Z^{i+1} \\ \Delta t_{\Delta}^{i+1} \end{bmatrix} = - \begin{bmatrix} \tilde{F} \\ \tilde{H} \\ \tilde{G} \\ 0 \end{bmatrix} \quad (5.9)$$

The time is updated by  $t^{i+1} = t^i + t_{\Delta}^{i+1}$  (5.10)

Now a new time trajectory point

$[X^{(i+1)T} \ Y^{(i+1)T} \ Z^{(i+1)T} \ \dot{X}^{(i+1)T} \ \dot{Z}^{(i+1)T} \ t^{i+1}]^T$  has been achieved.

### Avoiding singularity of $G_Y^{-1}$

Now, with proper selection of continuation parameter, the singularity of  $G_Y^{-1}$  does not affect the augmented Jacobian both for trajectory predictor and trajectory corrector. Solution no longer diverges during the DAE time domain integration.

## 5.3 Manifold Based Time Domain Simulation Procedure

- 1) Specify the initial / pre-contingency condition  $[X^{0T} \ Z^{0T} \ t_0]^T$  of the power system.
- 2) Calculate  $[Y^{0T} \ \dot{X}^{0T} \ \dot{Z}^{0T}]^T$  under contingency / post-contingency network configuration with (5.9)
- 3) Predict trajectory with (5.7) and (5.8)
- 4) Correct trajectory with (5.9) and (5.10)
- 5) Go to 3) until it reaches the specified end time for the simulation

### A Special Case: Quasi-Steady State Simulation (QSS)

If we neglect fast dynamics ( $\dot{X}=0$ ), the time domain integration is only performed on load dynamic variable  $Z$ .

## 6. Numerical Results

Unified margin boundary tracing is demonstrated through the numerical tests performed on the New-England 39-bus system.

The following conditions are implemented throughout all the simulations:

- Constant power loads;
- The maximum real power limit, the field current and the armature current limits are considered for each generator.
- No generator is allowed to have terminal voltage higher than 1.1 p.u., when its secondary voltage control is utilized to increase system stability margin;
- The loading scenario is defined as that all the loads are increased with constant power factor, and all the generators participate in the load pick-up at the same rate.

### 6.1 Identification of Hopf and SNB Bifurcation

Fig 6-1 shows the PV diagram for a given control configuration. Hopf bifurcation is identified for a total load increase of 809 MW (by observing simultaneous sign change

of  $\gamma_{H_1}$  and  $\gamma_{H_2}$ ). Saddle node bifurcation is observed for a total load increase of 1370 MW.

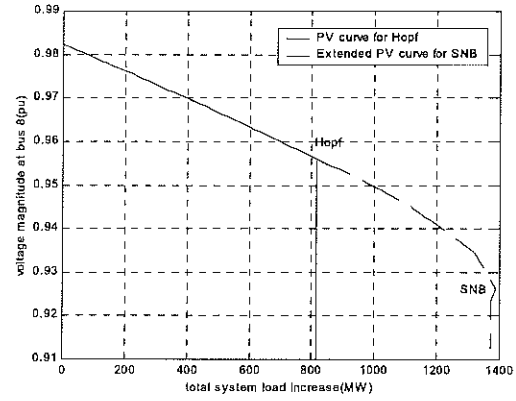


Figure 6-1: Hopf detection in PV curve tracing for base case control

### 6.2 Unified Margin Boundary Tracing

Fig 6-2 provides voltage and oscillatory stability margin boundaries with respect to the adjustment of AVR gain  $K_a$ . The  $K_a$  range for Hopf bifurcation confirms the analytical condition derived in [32].

Fig. 6-3 shows the both margins change with respect to variation of  $V_{ref}$ . The nonsmooth curves are due to the effects of limits on the boundaries.

Fig. 6-4 shows the effect of load shedding on voltage as well as oscillatory stability boundaries. In this case, load shedding increased both the margins.

Fig. 6-5 shows the effect of line outage. Here 1 corresponds to complete outage. For example, before line outage, the SNB related margin is 1390 MW. With line outage the margin decreased to 900 MW.

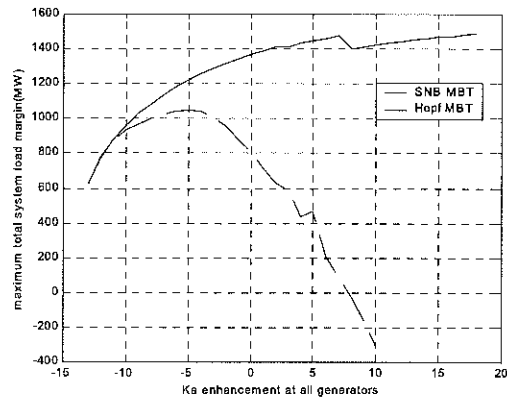


Figure 6-2: Unified margin boundary tracing versus change of  $K_a$

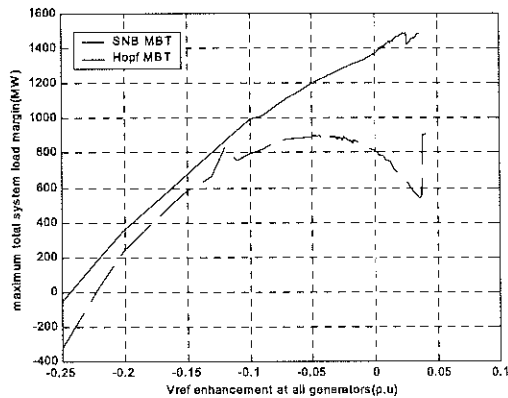


Figure 6-3: Unified margin boundary tracing versus Vref Adjustment

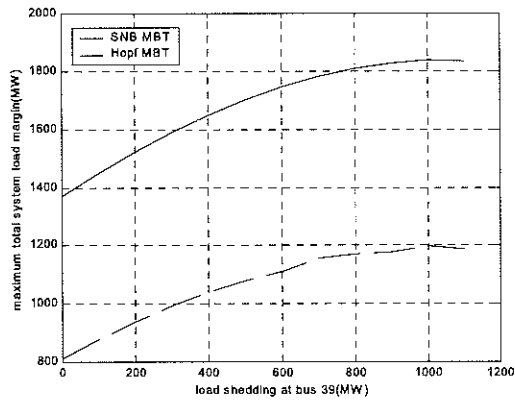


Figure 6-4: Unified margin boundary tracing versus load shedding

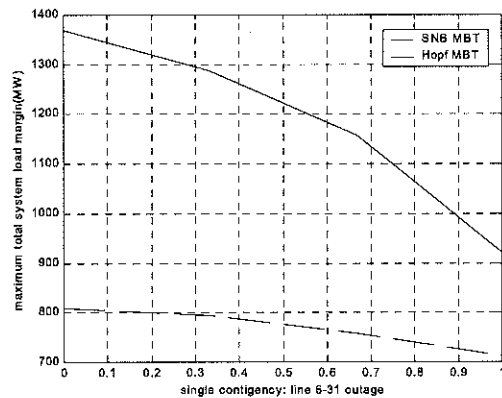


Figure 6-5: Unified margin boundary tracing versus line outage

### 6.3 Optimal Margin Boundary Tracing (OMBT)

Optimal margin boundary tracing is presented for a case with load shedding at buses 4, 7, and 8.

Fig. 6-6 shows the load shedding requirements for maintaining a given percentage margin. Solid curve (—) corresponds to nonlinear optimal margin boundary tracing where as dashed curve (+) corresponds to the margin sensitivity based linear programming. Linear programming (LP) based approach is accurate only up to 28% of the margin. Individual load shedding curves at bus 4, 7, and 8 are the components of OMBT total load shedding.

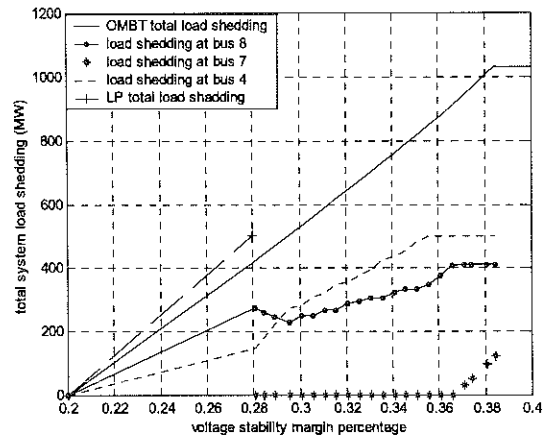


Figure 6-6: Marge boundary optimization comparison between OMBT and Linear Programming

## 6.4 Manifold Based Multi-Time Scale Time Domain Simulation

### 6.4.1 Time Domain Simulation for Small disturbance

Tim domain simulation corresponding to the Fig. 6-1 is shown in Fig. 6-8. For this simulation, fast dynamics are neglected. Load is increased at a specified rate. It is similar to quasi-steady state simulation. However if we consider fast dynamics in conjunction with load increase, Hopf bifurcation is detected at 30 sec as shown in Fig. 6-8.

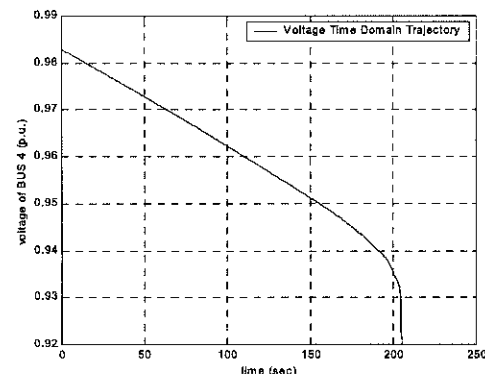


Figure 6-7: Quasi-steady state simulation

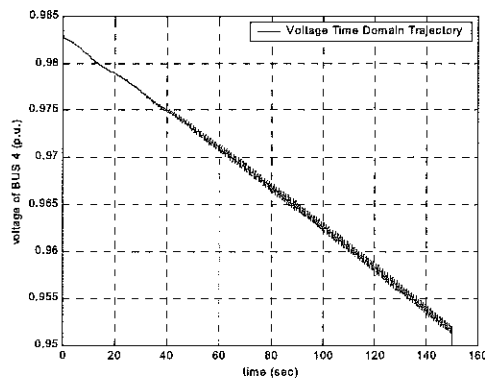


Figure 6-8: Small disturbance time domain simulation

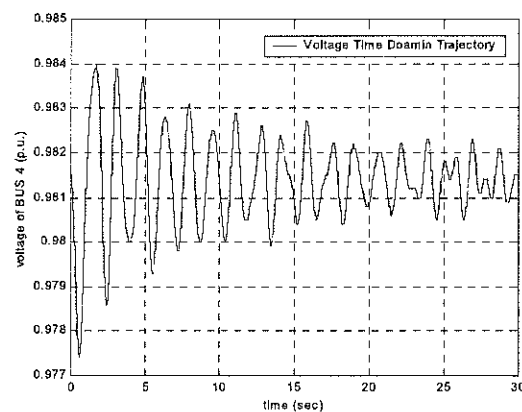


Figure 6-10: Line 8-9 is off at base condition with no load variation

#### 6.4.2 Time Domain Simulation for Large Disturbance

A contingency example is assumed that the branch from bus 7 to bus 8 is tripped at 80 sec. Fig 6-9 shows the time domain simulation. As we can see, this program could handle the hybrid time scale problem. It captured both slow and fast dynamics.

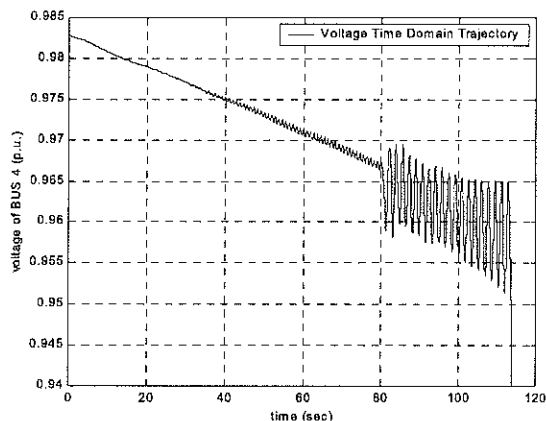


Figure 6-9: Line 8-9 is off at 80 sec

#### 6.4.3 Time Domain Simulation with No Load Variation

Here load is kept constant at its base value. Fig. 6-10 shows the time domain response for an outage of line 7 - 8 at base case.

### 7. Conclusions

In this paper, we presented a general approach that can be used

- To trace nonlinear voltage as well as oscillatory stability boundaries
- To find the minimum cost to obtain a specified margin
- To obtain numerically well conditioned time domain simulations for slow as well as fast dynamics

The salient features of the approach are:

- A unified framework to trace the margin boundary in multi-parameter space under specified loading and control scenario is presented. It can be applied to monitor the load margin variation constrained both by voltage collapse and system oscillations. It doesn't need eigenvalue calculation.
- We also proposed a nonlinear optimization method that calculates the minimum cost control solution for a given margin.
- A manifold based unified time domain simulation for voltage short term and long term dynamic stability analysis and corrective control is implemented. For a stressed system, numerical difficulty associated with traditional algorithms could be avoided.

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## A Theoretical Approach to Multiple Solution in Load Flow

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### Introduction

As transmission networks are operating closer to their limitation, security assessment is becoming more important for operating planning. Security assessment through theoretical investigation of vector space composed of load flow equations provides better understanding of power systems and control. It is known that multiple solutions in load flow studies act significant effects on security assessment. This paper presents a theoretical approach to multiple solutions in load flow studies for power system voltage stability analysis and control. Conventional load flow equations in complex vector space are modified into a set of quadratic forms as new mathematical models for convenience of theoretical procedures of multiple solutions and others in power system analysis. The proposed method based on the Taylor expansion of the new model around a base case solution of a loading condition. It leads to a set of equations and necessary condition for multiple solutions under assumption of same active and reactive powers but different voltages. The necessary condition of multiple solutions is denoted as determinant of sum of Jacobian at base case solution and Jacobian at another solution is equal to zero. Author tried to prove the theory with use of multiple solutions obtained by Monte Carlo like simulation for small size examples. Many set of solutions are obtained in a model of lightly loaded Kios and Kerner's 11 nodes. All solutions are checked of difference from each other in the set. The necessary condition is verified with use of these solutions. The determinants of the sum of Jacobians are calculated by methods of triangulation and LU decomposition. One of diagonal elements of calculated matrices becomes very small absolute value in both methods. Ward and Hale 6 nodes model has only two set of load flow solution. Determinants for the necessary condition is calculated at points on a straight line between base case solution and another solution. Also, determinant of Jacobian on same points in former case are calculated. Comparison of these results are discussed and examined in the point of view of multiple solution and necessary condition.

### Load Flow Equation

System of equations of load flow with use of nodal admittance matrix and nodal voltages is known as following equation (1)

$$P_i + jQ_i = E_i \sum_{j=1}^n (Y_{ij} E_j)^* \quad (k=1, 2, \dots, n) \quad (1)$$

where nodal voltages and element of admittance matrix are defined as following

$$E_i = e_i + jf_i \quad (2)$$

$$E_j = e_j + jf_j \quad (3)$$

$$Y_{ij} = G_{ij} + jB_{ij} \quad (4)$$

Substituting eqs. (2)~(4) into eq. (1), and separating real and imaginary parts, then active and reactive powers become as following eqs. (5) and (6).

$$P_i = \sum_{j=1}^n \{ e_i (G_{ij} e_j - B_{ij} f_j) + f_i (B_{ij} e_j + G_{ij} f_j) \} \quad (5)$$

$$Q_i = \sum_{j=1}^n \{ f_i (G_{ij} e_j - B_{ij} f_j) - e_i (B_{ij} e_j + G_{ij} f_j) \} \quad (6)$$

Equation of voltage specified node is given as follows.

$$v_i^2 = e_i^2 + f_i^2 \quad (7)$$

### Quadratic Forms

The following equations (8) and (9) of active and reactive powers are derived with use of nodal voltage vectors and branch admittance matrix from eq. (5).

$$P_i = \sum_{j=1}^n \left\{ \begin{bmatrix} e_i \\ f_i \end{bmatrix}^T \begin{bmatrix} G_{ij} & -B_{ij} \\ B_{ij} & G_{ij} \end{bmatrix} \begin{bmatrix} e_j \\ f_j \end{bmatrix} \right\} \quad (8)$$

$$Q_i = \sum_{j=1}^n \left\{ \begin{bmatrix} e_i \\ f_i \end{bmatrix}^T \begin{bmatrix} -B_{ij} & -G_{ij} \\ G_{ij} & -B_{ij} \end{bmatrix} \begin{bmatrix} e_j \\ f_j \end{bmatrix} \right\} \quad (9)$$

Quadratic form has to have symmetric coefficient matrix. Sum of eq. (8) can be decomposed into three parts with respect to subscript  $j$ , as follows

$j=s$  : term of contribution of slack node,

$j=i$  : diagonal block,

others : off-diagonal blocks.

Off-diagonal blocks with asymmetric coefficient matrices in eq. (8) are deformed into sum of halved block and transposition of another halved block with symmetric

coefficient matrices. Diagonal block is easy to derive a term with symmetric matrix.

Contribution of a slack node is written in the form of twice of halved coefficients. Therefore, active power with asymmetric coefficient matrix of eq. (8) is transformed into an expression with symmetric matrix as shown in eq. (10).

$$P_i = \sum_{j=1, j \neq i, n}^n \left\{ \begin{bmatrix} e_i \\ f_i \end{bmatrix}^T \begin{bmatrix} G_{ij}/2 & -B_{ij}/2 \\ B_{ij}/2 & G_{ij}/2 \end{bmatrix} \begin{bmatrix} e_j \\ f_j \end{bmatrix} + \begin{bmatrix} e_j \\ f_j \end{bmatrix}^T \begin{bmatrix} G_{ij}/2 & B_{ij}/2 \\ -B_{ij}/2 & G_{ij}/2 \end{bmatrix} \begin{bmatrix} e_i \\ f_i \end{bmatrix} \right\} + \begin{bmatrix} e_i \\ f_i \end{bmatrix}^T \begin{bmatrix} G_{ii} & 0 \\ 0 & G_{ii} \end{bmatrix} \begin{bmatrix} e_i \\ f_i \end{bmatrix} + 2 \begin{bmatrix} (G_{ii}e_i - B_{ii}f_i)/2 \\ (B_{ii}e_i + G_{ii}f_i)/2 \end{bmatrix}^T \begin{bmatrix} e_i \\ f_i \end{bmatrix} \quad (10)$$

Similarly, expression of reactive power is obtained as following equation (11).

$$Q_i = \sum_{j=1, j \neq i, n}^n \left\{ \begin{bmatrix} e_i \\ f_i \end{bmatrix}^T \begin{bmatrix} -B_{ij}/2 & -G_{ij}/2 \\ G_{ij}/2 & -B_{ij}/2 \end{bmatrix} \begin{bmatrix} e_j \\ f_j \end{bmatrix} + \begin{bmatrix} e_j \\ f_j \end{bmatrix}^T \begin{bmatrix} -B_{ij}/2 & G_{ij}/2 \\ -G_{ij}/2 & -B_{ij}/2 \end{bmatrix} \begin{bmatrix} e_i \\ f_i \end{bmatrix} \right\} + \begin{bmatrix} e_i \\ f_i \end{bmatrix}^T \begin{bmatrix} -B_{ii} & 0 \\ 0 & -B_{ii} \end{bmatrix} \begin{bmatrix} e_i \\ f_i \end{bmatrix} + 2 \begin{bmatrix} -(B_{ii}e_i + G_{ii}f_i)/2 \\ (G_{ii}e_i - B_{ii}f_i)/2 \end{bmatrix}^T \begin{bmatrix} e_i \\ f_i \end{bmatrix} \quad (11)$$

Also, we can write a quadratic form of voltage control equation as follows.

$$v_i^2 = \begin{bmatrix} e_i \\ f_i \end{bmatrix}^T \begin{bmatrix} 1 & 0 \\ 0 & 1 \end{bmatrix} \begin{bmatrix} e_i \\ f_i \end{bmatrix} \quad (12)$$

Sticking symmetric block matrices on a full matrix of  $m$ -th order, quadratic forms of active and reactive powers, and voltage control are derived as following equations (13) ~ (15), respectively.

$$P_i = x^T A_{ik} x + 2b_{ik}^T x \quad (13)$$

$$Q_i = x^T A_{ij} x + 2b_{ij}^T x \quad (14)$$

$$v_i^2 = x^T A_{ik} x + 2b_{ik}^T x \quad (15)$$

General expression described above is as follows

$$y_k(x) = x^T A_k x + 2b_k^T x \quad (k=1, 2, \dots, m) \quad (16)$$

Transposing  $y_k$  from left side to right in eq. (16), the equation of quadratic surface is derived as follows

$$F_k(x) = x^T A_k x + 2b_k^T x + c_k = 0 \quad (k=1, 2, \dots, m) \quad (17)$$

### Necessary Condition for Multiple Solutions

Expanding eq. (16) in Taylor series near the base case solution  $x_0$ , following equation is obtained.

$$y_k(x) = y_k(x_0) + J_k(x_0)\Delta x + \frac{1}{2}\Delta x^T H_k(x_0)\Delta x \quad (18)$$

where

$$J_k(x_0) = 2(A_k x_0 + b_k)^T \quad (19)$$

$$H_k(x_0) = 2A_k \quad (20)$$

$$\Delta x = x - x_0 \quad (21)$$

Transposing first term of right hand side in eq. (18) to left hand side, and letting it as  $\Delta y_k(x)$ , we obtain following equation.

$$\begin{aligned} \Delta y_k(x) &= y_k(x) - y_k(x_0) \\ &= J_k(x_0)\Delta x + \frac{1}{2}\Delta x^T H_k(x_0)\Delta x \end{aligned} \quad (22)$$

Multiple solutions of load flow are define as  $\Delta y_k(x) = 0$  at  $\Delta x \neq 0$  in eq. (22).

Substituting eqs. (19) and (20) into eq. (22), then eq. (23) is obtained.

$$2(A_k x_0 + b_k)^T \Delta x + \frac{1}{2}\Delta x^T 2A_k \Delta x = 0 \quad (23)$$

Eq. (23) is factorized as follows,

$$[A_k \Delta x + 2(A_k x_0 + b_k)]^T \Delta x = 0 \quad (k=1, 2, \dots, m) \quad (24)$$

Substituting eq. (21) into (24), an expression is obtained in the form of sum of Jacobian matrices with respect to a multiple solution and the base case solution as following equation (25).

$$\frac{1}{2}[J_k(x) + J_k(x_0)]^T (x - x_0) = 0 \quad (k=1, 2, \dots, m) \quad (25)$$

Complete set of simultaneous equations (25) can be written as follows.

$$[J(x) + J(x_0)]^T (x - x_0) = 0 \quad (26)$$

Equation (26) is homogeneous. If solution of the equation is not trivial, necessary condition is derived as follows.

$$\det[J(x) + J(x_0)] = 0 \quad (27)$$

### Numeric Examples

Numeric behavior of the necessary condition (27) for multiple solutions in load flow study is examined with numeric examples of several small models.

Base case solution is calculated with use of ordinary load flow program substituting flat initial guess. Multiple solutions



are calculated with the program starting from initial guess generated by random procedure of Monte Carlo simulation.

#### Ward and Hale's 6 nodes model

Two set of solutions are obtained by means of Monte Carlo procedures. Logarithms of norm of mismatches are evaluated, and resulted as -10.38777 and -8.34812, respectively. Distance between two set of solutions is 2.34079. Characteristics of determinant of the necessary condition are calculated along a straight line through the base case solution ( $t=0$ ) and another solution ( $t=1$ ), and plotted on a graph as shown in Fig. 1.

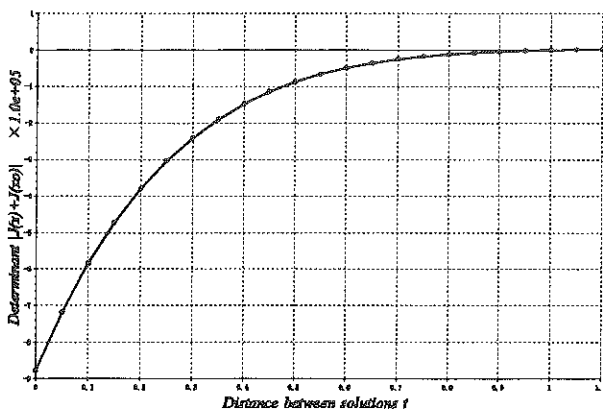


Fig.1 Characteristics of determinants  $|J(x)+J(x_0)|$

Behaviors of Jacobian are evaluated on the line, and plotted as shown in Fig. 2. Characteristics of Jacobian  $|J(x)|$  has a null point at the mid point between two solutions.

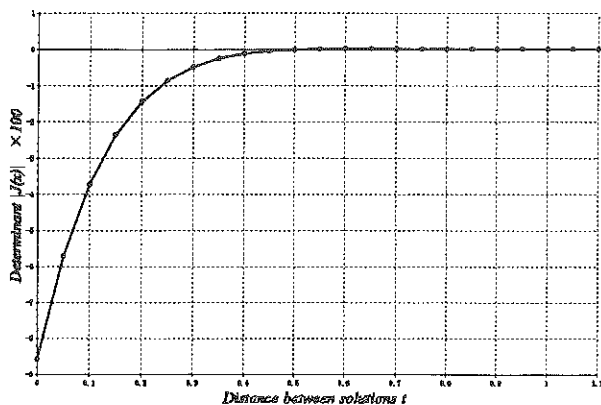


Fig.2 Characteristics of Jacobian  $|J(x)|$

Characteristics functions  $y_k(x)$  on the line are calculated, and plotted on a graph as shown in Fig.3. Each function shows a parabolic curve, and has a maximum value or minimum value at the mid point between two solutions.

#### ElAbiad's 5 nodes model

Four set of solutions are found by the multiple solution program.

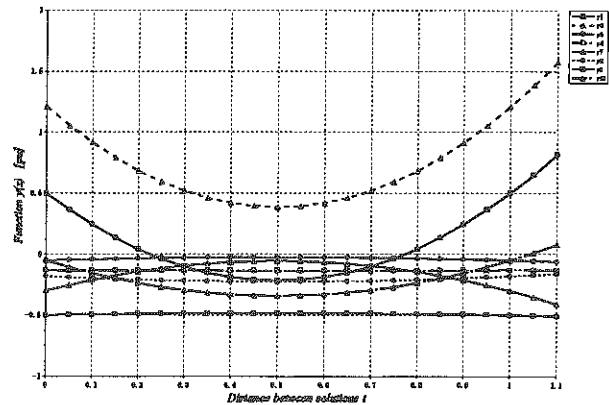


Fig.3 Characteristics of functions  $y_k(x)$

Norm of mismatches are calculated in logarithmic forms as -14.23643, -14.99887, -15.04128 and -14.59590, respectively. Norm of distance between  $x_i$  and  $x_j$  is calculated as follows.

$$d_{ij} = \|x_i - x_j\| = \sqrt{\sum_{k=1}^n (x_{i,k} - x_{j,k})^2} \quad (28)$$

Angle between  $x_i$  and  $x_j$  is calculated as follows

$$\theta_{ij} = \cos^{-1}((x_i, x_j)) \quad (29)$$

Mid points of solutions are calculated as follows

$$x_m = \frac{x_{i1} + x_{iL}}{2} \quad (30)$$

Function  $\|y_m\|$  is calculated as follows

$$\|y_m\| = \sqrt{\sum_{k=1}^n y_k^2(x_m)} \quad (31)$$

Table 1 Characteristic values between solutions

| $i:j$ | $d_{ij}$ | $\theta_{ij}$ [deg] | $\ y_m\ $ |
|-------|----------|---------------------|-----------|
| 0:1   | 1.6483   | 43.187              | 13.7974   |
| 0:2   | 1.6562   | 43.601              | 13.7696   |
| 0:3   | 1.2084   | 27.880              | 15.0643   |
| 1:2   | 0.014962 | 1.163               | 9.58487   |
| 1:3   | 0.76382  | 43.670              | 10.6913   |
| 1:4   | 0.76093  | 43.270              | 10.6633   |

Determinants of the necessary condition and Jacobian's determinants are calculated on the straight line, and plotted as shown in Fig. 4.

The curve of the necessary condition crosses the zero axis at  $t=1$ , which correspond to another solution. On the other hand, the curve crosses zero at  $t=0.5$ , where is mid point.

#### Klos & Kerner's 11 nodes model

130 set of solutions are found by the program. Mismatches of the solutions are calculated, and plotted in Fig. 5. Most logarithmic mismatches are of values about -13.

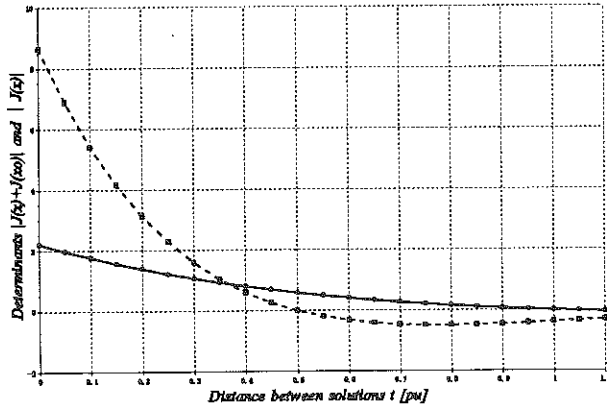
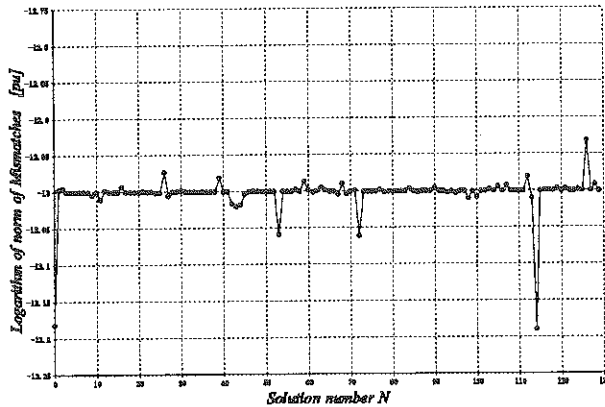
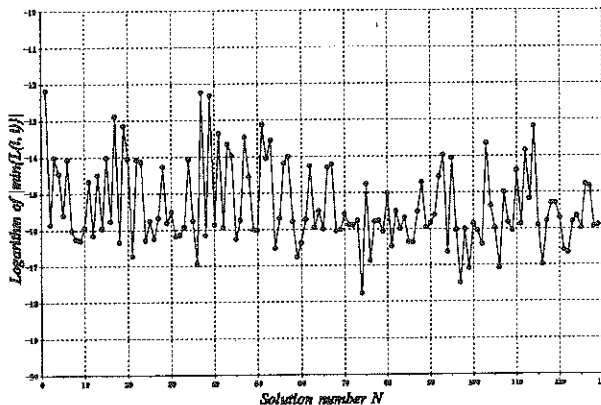
Fig.4 Characteristics  $|J(x) + J(x_0)|$  and  $|J(x)|$  for  $x_0 x_3$ 

Fig.5 Mismatches of Load Flow of 130 solutions

Fig.6. Minimum values of diagonal element  $L(i,i)$  for necessary condition of 130 solutions

Instead of the calculation of determinant of necessary condition, matrix of necessary condition is decomposed in the form of  $LU$ . If all diagonal elements of the upper triangular matrix  $U$  is unity, the minimum value of diagonal elements of matrix  $L$  is the index of the determinant of singular matrix.

Minimum values of diagonal elements of the matrix  $L$  to the necessary condition for 130 set of solutions are plotted in Fig. 6. The plotting points are distributed in the range of -12 to -18 in logarithmic scale. These results are considered as zero.

Maximum and minimum distances between a solution and another ones are calculated from the results of 130 set of multiple solutions, and plotted in Fig. 7. The most closest distance is longer than 0.037 [pu].

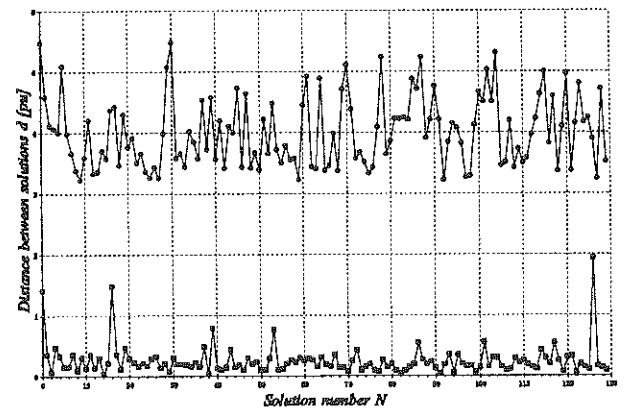
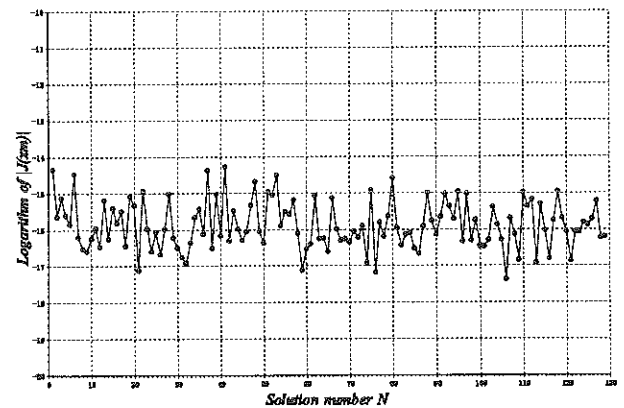


Fig.7 Max. and min. distances from another solution

Jacobian's determinants are calculated with respect to the mid points between the base case solution and others, and results are shown in Fig. 8. The determinants  $|J(x_m)|$  might be zero at mid point between arbitrary two set of solutions.

Fig. 8 Characteristics of determinants of Jacobian  $|J(x_m)|$ 

Logarithmic values of minimum diagonal elements of lower triangular matrix  $L(i,j)$  for Jacobian's determinants in Fig. 8 are distributed within the range -14 to -18.

#### Model of IEEE14

27 set of solutions are found in this model. Mismatches are calculated for 27 set of solutions and results are plotted by logarithmic values in Fig. 9. Observing the graph in Fig. 9, the solutions are solved with reasonable accuracy.

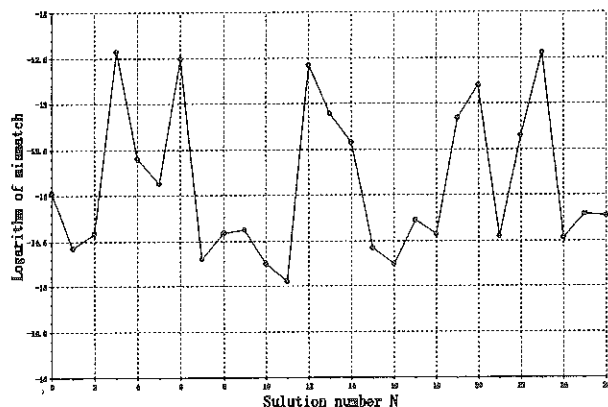


Fig.9 Logarithmic mismatches for 27 set of solutions

Determinants of the necessary condition are calculated, results are plotted in Fig. 10 with logarithmic scale. The results show the fact that solutions satisfy the condition.

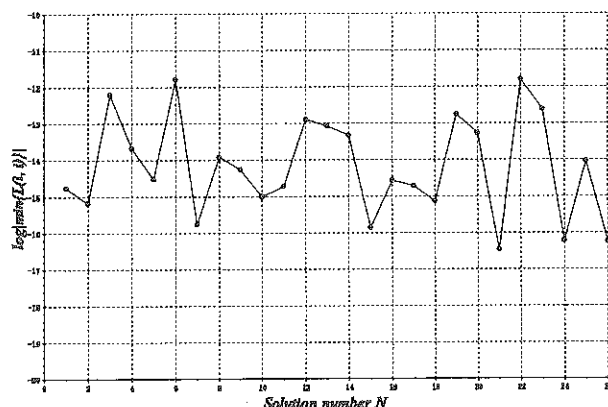


Fig.10 Evaluations of necessary condition

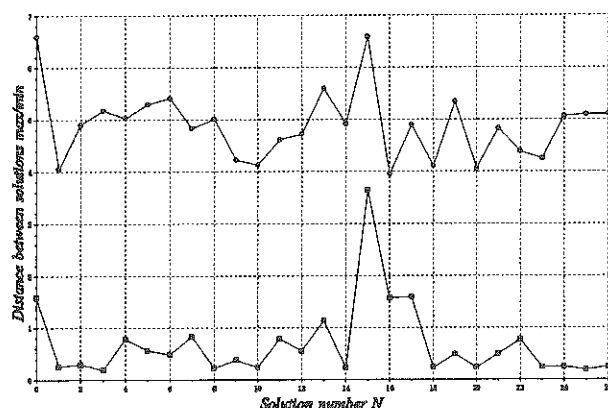
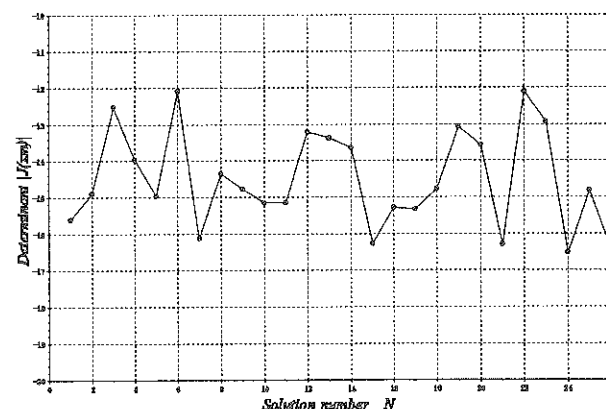


Fig. 11 Max. and min. distances between solutions  
Norm of distances between solutions are calculated. Results of maximum and minimum distances between a selected set of solution and others are plotted in Fig. 11. The shortest distance for the model is 0.198 [pu].

Jacobian's determinants are calculated with respect to the mid points between the base case solution and others, and results are shown in Fig. 12. The determinants  $|J(x_m)|$  might be zero at mid point between arbitrary two set of solutions.

Fig. 12 Characteristics of determinants of Jacobian  $|J(x_m)|$ 

Logarithmic values of minimum diagonal elements of lower triangular matrix  $L(i,j)$  for Jacobian's determinants in Fig. 12 are distributed within the range -12 to -17.

### Conclusion

This paper shows mathematical derivation of a necessary condition of multiple solutions in load flow study from the fundamental equation. The theory is proved by means of numeric substitutions of multiple solutions obtained by the program of Monte Carlo simulation, experimentally. The author confirmed the validity of multiple solutions calculating mismatches and minimum distances between solutions. The necessary condition is satisfied by all solution. Also, Jacobian's determinant becomes zero at any mid point between arbitrary two set of multiple solutions.

The author expects the direct method of multiple solutions in load flow, if we can select vectors  $x$  which satisfy the equation (27). From another point of view, it might be possible to use the property of which Jacobian's determinant becomes zero at mid point between arbitrary two set of solutions.

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## Discussions on Session VIII: SYSTEM ANALYSIS Part 2

**I. Dobson:** I have a question for Professor Ajjarapu. Suppose you are on an operating point, and you increase your load in a certain direction and generator 1 is not reaching a Q limit, and you found the boundary. Suppose you go off to another direction of load increase, and generation 1 did reach Q limit, and then you found the boundary in that case. Then, in that case you're going to have two different boundaries, say one corresponding to generator 1 having a reactive power limit on, and another portion corresponding to no reactive power limit, and they are both parts of the actual performance boundary. I'm concerned that if you follow your procedure of going out of those surfaces and continuing along that surface, you'll miss the second boundary so I want to ask you about that.

**V. Ajjarapu:** You're saying, in one case, you have a generator limit, right? It assumes that you reach the boundary point. I include all the limits, the boundary point as well as boundary tracing.

**I. Dobson:** It's not clear to me that reactive power limit would be one of your control parameters necessarily. I mean you may or may not include that reactive power limit as a part of your control parameter space. I guess I'm asking, I don't know.

**V. Ajjarapu:** Good point. But the point is I didn't change the reactive power limit as a parameter. If you consider other than the reactive power limit, so when I'm tracing, automatically I'm checking whether other generators are hitting the limit and so on. Then I'll read that when points to that limit. But with the respect to that reactive power limit variation, I think that's maybe what you're asking. In our simulation, we didn't do that. We may have a problem if we address that reactive power variation.

**C. Vournas (NTUA):** Follow up to Ian's question. If you follow what I write on my paper, you may have points where two loadability branches cross. Now if you're at this point, you're at the crossroad. So you have to solve for Lagrange multiplier that would tell you which of the branches you follow. It's a crossroad.

**V. Ajjarapu:** Yes. You have to decide which branch to follow at two directions. I agree. Also I have to point out here. You ask because the two-parameter variation, when the boundary turns back, there may be problems, then we have to modify this. But by the time you reach that, maybe you're reaching all that control limits. But if you reach that again, you have to modify, then this formulation doesn't apply.

**Chairman:** Ian presented a technique for solving inverse problems. This morning I presented a framework. I'm wondering if we should get together again. Could you just comment generally on what your approach is going to provide in "life is optimal control of optimization?" I have been studying control theory again recently, and it seems like everything that is useful has ever been done has some reference to optimal control. So there is certainly something in that statement. But could you make some extra comments on how what you presented it ties in?

**I. Hiskens:** In terms of the framework, we have been pursuing control variables. So if you look at the load shedding, which is really based on blocks. It is not a smooth parameter at the shedding time it is smooth parameter you can make that around. What we've been playing around with, and this is still early day to try if my thing works. You play around the amount of load shed and run an optimization over to the load shedding amount. That thing gives you a good feel for under an optimal condition what is best to do, you should be shedding load here, and a little bit there, or all those kinds of things. Then to decide, lock in the discrete or discrete value, and move the shedding time around just under a normalization process again. So you don't end up with the absolute optimum. It's a little like tap power flow. If you do that in terms of the actual discrete tap, you can get some interesting oscillations, also you can get multiple solutions. If your tap positions are continuous variables, run them, and then do the processes to set them back to the closest discrete value. That can get you a good answer most of the time. It is heuristic but I think it is necessary sometimes.

**P. Sauer:** I have a question for Professor Sato. You and I share a great interest in circles and also in quadratic forms. I spent probably a year trying to develop a closed form solution to a two variable system, just two. I wasn't worried about ten thousand. I came very close to a closed form quadratic equation for two variables. I'm curious if you have tried closed form quadratic formulas for one variable, or if you haven't, do you think quadratic solution does not exist maybe?

**H. Sato:** Thank you for the question. I derived a quadratic equation in this. I show the circle diagram convenient to illustrate on screen, if we calculate more than 3 nodes, for example, the 3 nodes mean dimension, surface, and coordination system, then it is understood that it is very difficult. So I chose the bus system. If the dimension over the circle becomes a quadratic surface,

the quadratic surface has a common point. That is the solution of the load flow equation.

**P. Sauer:** I'd just ask one little more question. There has been debate over the years about the numbers of solutions. I always felt that for any load flow I can find there are always two to the  $n$  minus one.

**C. C. Liu:** I want to come back to this paper that Ian presented. I think in a way it is also related to what David presented. It's a very nice framework, and you have good illustrations. The question I have: how far we can go on this? How tractable will it be? Two examples I can think of. The first one is typically continuous variables, if you have tap changers, you're going to have these unreasonable numbers, and so a quick way is to put some heuristics. The other one is, we analyze the transient stability, so we study prefault operating point, and fault-on period, but then if the tap changer moves, you're back to square one. You have a completely new region and new equivalent point. It's all coming back to the same reason that Ian mentioned. Analytically, there is not much we can do for that type of problems. Probably a more heuristic or search-type of methods might help find some useful solutions, and probably not very elegant but useful solutions. I don't know if Ian wants to respond to this.

**I. Hiskens:** Sure. I think the ultimate one combination of the traditional continuous optimization idea along with combinatorial type search, and tree pruning type things, and index. As you said there are a lot of difficult problems. We launch into a very simple case with two large load being shed and just looking at its behavior optimization technique for that simple case. It's not straightforward. There are other interesting aspects as well. In the case of the load shedding one, you want to delay load shedding time. To delay beyond its last time, this system is unstable. In fact what you're trying to do is to push this system. This rapid change from being the optimal solution to a very non-optimal solution calling instability create its own difficulty before you even start thinking about it. So we don't claim to solve the problem. But we're establishing a framework into that.

**Chairman:** Just to add a little bit. The way I see it is the hybrid system creates a framework to explore. Some issues are trickier than the continuous time results. We have lots of stuff, which is useful, and continuous optimization for tap changer work is just fine in lots of situations, but not in all. We need tools to address those special cases. It's tough, we have to somehow deal with it.

**I. Hiskens:** I'll just add another comment. The old framework looking at the fault-on that worked really very well in a lot of cases. I don't really need a control device for that kind of thing. It's not an event that is time driven. There is not a switching time or tripping time.

That's actually a response to other things that happen in the system. If you want to start to get to the state-driven type of events, then there is no other framework to go into.

**L. Fink:** I guess this is not so much a question, it's a comment. I like very much what he's attempting to do and the way he's going about it. But I guess I had a better interest in this matter of load shedding. I think it is safe to say, unless we're talking about two different phenomenon, that an attempt to get an optimal load shedding program is oxymoronic, pardon me for that expression. Because there is too many inponderables involved. For instance, if you set a block of load to be shed, you really have no handle on what the amount, because that's a variable. When you come to load shedding, the system is in problem. To attempt to go about it in a timid fashion is counter productive. I like what you're doing but I'm not sure load shedding is a good thing to try it on.

**I. Hiskens:** The choice of load shedding is because it's very hard, it's state-driven. It's a difficult case, that's why we do it. It did relate back to a project I had with back in Australia, where the idea was in part of a very much constrained transmission system, they wanted to know where is the best place to shed load. While we're doing that study, there was no way to do that apart from trying this and that. Can we do better than that? Can we put it into a loop that says selecting location and parameters? I agree that load shedding is the last line of defense, if you shed load, everyone is going to scream anyway.

**L. Fink:** I think there are heuristics. Some are in the paper. I think it's going to be a good number of years ago now.

**Chairman:** Yes, we can talk about that for a while. I think we're stuck with them. And this is where certainly the techniques like Chen-Ching uses, and other ways you combine heuristics. We have to get engineering experiences in this some way. AI techniques are probably the best way to do that. In combination we think there's lot to be got from those techniques. Any further questions? Let's thank the speakers.

**Session IX:**  
**STABILITY ASSESSMENT &**  
**RESTORATION**

Friday, August 31, 09:00–12:00

Chair: Hiroaki Sugihara

# Information of SIME-Based Transient Stability Assessment and Control Techniques: Description and Classification

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**Abstract:** SIME-based transient stability assessment and control techniques provide a wide range of information. This paper highlights various types and classifies them into two categories, according to their functionalities and potential users. One may thus distinguish synthetic or detailed information of analysis or control type, relative to ATC calculations or congestion management and corresponding generation patterns. The selection among these multiform pieces of information depends on specific requirements of the end users: dispatchers, operators, operation planners, researchers, etc. The various types of information and their classification are illustrated by means of simulation results performed on real-world power systems.

**Keywords:** Transient stability assessment and control; contingency filtering, ranking and assessment; real-time preventive control; dynamic security assessment; SIME method.

## 1 Introduction

In the liberalized electric industry, generation schedules for the next day are set up now by its financial structure. Trade of bulk power in an auction market or/and by bilateral contracts directly signed between the producer and the consumers shape generation for the next day, using forecasted system conditions. The use of one or both of the aforementioned trading methods depends on the structure of the electric industry under consideration. The real load curve and conditions of the system are generally different from the forecasted ones, and the transmission system operator is responsible of solving these differences by matching, in real-time, generation with real demand while respecting all static and dynamic security constraints.

Achieving this task in the real-time context requires designing suitable security functions, compatible with various market rules. These security functions should be able to provide the operator the necessary information to take decisions in order to correct system conditions. The methods employed by the security functions should be as transparent, non-discriminatory and objective as possible for justifying operator's decisions.

Such functions dedicated to transient stability are derived from the SIME method which, thanks to its very concept provides rich, multiform and flexible information.

In very brief, SIME (for Single Machine Equivalent) is a generalized single-machine hybrid direct-time-domain method [1]. It transforms the multimachine system trajectory provided by a time-domain program into the trajectory of a one-machine infinite bus (OMIB) equivalent system, suitably defined. By refreshing the OMIB parameters continuously and by using the general-

ized equal-area criterion to assess the resulting OMIB dynamics, SIME evades the weaknesses of direct and time-domain methods, while combining and further augmenting their advantages: accuracy and flexibility of time-domain methods with respect to system modeling, contingency scenarios and types of instabilities, on the one hand; significant enhancement of time-domain methods, which are typically restricted to mere analysis, on the other hand. In short, SIME paves the way for improved analysis and - even more important - for control.

An example of improved analysis is the contingency filtering, ranking and assessment software recently developed for real-time transient stability assessment (TSA) [2, 3]. Control is another example of techniques designed to furnish real-time stabilization countermeasures [4 to 7]. The integration of the above two functions, possibly combined with an OPF algorithm, yields a unified approach to Transient Stability Assessment and Control (TSA&C). Such TSA&C techniques are able to tackle issues which have long been considered as "not feasible in real-time operation" [8], and, further, to comply with requirements of various categories of end users and application contexts.

The aim of this paper is to set up an exhaustive list of method's manifold possibilities so as to help potential users take full advantage, in particular when interactions with the electricity market are of concern. The various pieces of information are then classified according to two criteria. One concerns types of information, the other classes of end users.

The paper is organized as follows. Section 2 recalls SIME's fundamentals and resulting basic information. Sections 3 and 4 deal with the two main functions which make up the TSA&C software and identifies pieces of information that they provide. Section 5 deals with a functional taxonomy, then proposes a selection of information suitable for four types of end users: dispatchers, operators, operation planners and R&D engineers. Throughout, the descriptions are illustrated by simulation results obtained with real-world power systems.

## 2 SIME: Basic concepts and information

### 2.1 Notation

All symbols are fully defined at the place where they are first introduced. Some of the more frequently used ones are collected below.

|            |                                                                                    |
|------------|------------------------------------------------------------------------------------|
| CCT        | Critical Clearing Time                                                             |
| CM         | Critical Machine                                                                   |
| CT         | Clearing Time                                                                      |
| NM         | Non-critical Machine                                                               |
| $n$        | total number of system machines                                                    |
| OMIB       | One-Machine Infinite Bus                                                           |
| $P_e, P_m$ | respectively OMIB electrical output power and mechanical input power               |
| $P_a$      | OMIB accelerating power: $P_a = P_m - P_e$                                         |
| SIME       | Single Machine Equivalent                                                          |
| $\delta_r$ | OMIB “return” angle, i.e., OMIB maximum angular deviation on a stable trajectory   |
| $\delta_u$ | OMIB unstable angle                                                                |
| $t_r$      | “return” time, i.e. time to (reach) stability conditions, i.e. to reach $\delta_r$ |
| $t_u$      | time to (reach) instability conditions, i.e. to reach $\delta_u$                   |

## 2.2 Foundations

The multimachine power system parameters provided by a time-domain program are transformed into those of a one-machine infinite bus (OMIB) system, and refreshed at each time step of the program. Further, at each time step, the stability of the OMIB is explored by the Equal Area Criterion (EAC); the procedure is stopped as soon as the (in)stability conditions of the EAC are reached (see below).

More precisely, after a contingency inception and its clearance, SIME drives a time-domain program so as to accomplish the following tasks: identify the critical and non critical machines and aggregate them into two groups; replace these groups by successively a two-machine, then an OMIB equivalent system; assess transient stability of this OMIB, using the EAC [7]. The various steps of the method are briefly described below and illustrated in Figs 1 drawn for a 3-machine system. For more details about SIME, see [7].

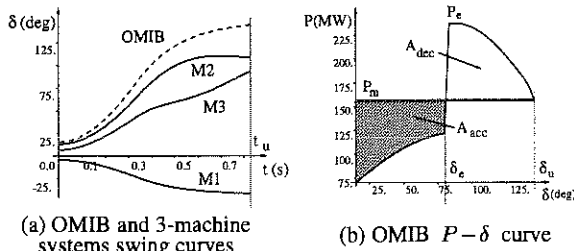


Fig. 1. Swing curves and OMIB  $P-\delta$  representation of a 3-machine system  
CCT = 334 ms ; CT = 335 ms . Adapted from [7]

## 2.3 Identification of the critical machines (CMs)

By definition, the critical machines are those which cause the system loss of synchronism. To identify them, SIME drives the time-domain transient stability program, and, as soon as the system enters the post-fault phase, it starts considering a few candidate decomposition patterns, by: (i) sorting the machines according to their rotor angles; (ii) identifying the very first largest rotor angular deviations (“distances”) between adjacent machines; (iii) considering as candidate CMs those which are above each one of the (say, 5) largest distances. The procedure is carried out until

a candidate group of CMs and corresponding OMIB reaches the unstable conditions (3) defined below. It is then declared to be the critical OMIB of concern or simply the OMIB<sup>1</sup>.

## 2.4 OMIB parameters, instability/stability conditions and margins

The OMIB parameters  $\delta, \omega, M, P_m, P_e$  are computed from the corresponding individual machines parameters, using the concept of partial center of angle. On the other hand, the EAC states that the stability margin is the excess of the decelerating area over the accelerating area (Fig. 1b):

$$\eta = A_{dec} - A_{acc}.$$

Accordingly, the following analytical expressions for unstable and stable margins are derived:

$$\eta_u = -\frac{1}{2}M\omega_u^2 \quad (1)$$

$$\eta_{st} = \int_{\delta_r}^{\delta_u} |P_a| d\delta. \quad (2)$$

In these expressions,

- $P_a$  is the accelerating power:  $P_a = P_m - P_e$ ,
- subscript  $u$  (for unstable) refers to the angle  $\delta_u$ , speed  $\omega_u$ , and time  $t_u$  when the OMIB instability conditions are met:

$$P_a(t_u) = 0; \dot{P}_a(t_u) > 0 \quad (3)$$

- subscript  $r$  (for return) refers to the “return” angle  $\delta_r$  and time  $t_r$  where  $\delta$  starts decreasing and  $\omega$  vanishes (OMIB stability conditions):

$$\omega(t_r) = 0; P_a(t_r) < 0. \quad (4)$$

Figs 1 illustrate SIME in an unstable case.

**Note.** The OMIB used in (2), (4) is defined on an unstable simulation. Therefore, these expressions are valid if the stable simulation under consideration is close enough to the stability boundary where, by definition,

$$\delta_r = \delta_u; \omega_r = \omega_u = 0.$$

## 2.5 Stabilization

According to SIME, stabilizing an unstable contingency scenario consists of cancelling out its (negative) margin. The EAC suggests and Fig. 1b illustrates that, in terms of the OMIB parameters, this corresponds to decreasing the OMIB mechanical power (unless the instability is of the back-swing type, for which the OMIB mechanical power should be increased). The application of the EAC can guide the search of the amount of OMIB generation change,  $\Delta P_m$ , needed to cancel out the margin.

In terms of the multimachine system parameters, it can be shown that, in turn, when the total generation is kept unchanged,

$$\Delta P_m = \Delta P_C = -\Delta P_N \quad (5)$$

<sup>1</sup>Note that conditions (3) provide an unambiguous identification criterion of the CMs. This is a major achievement of hybrid one-machine equivalent methods. Note also that the procedure involves very unexpensive computations.



where  $P_C$  (respectively  $P_N$ ) stands for generation power of the CMs (respectively of the NMs) [7].

In other words, SIME provides an initial approximate amount of generation to shift from CMs to NMs in order to stabilize an unstable scenario.

The way of refining this approximate assessment is sketched below, in § 2.6.5. Note, however, at once, that the distribution of total generation changes among CMs and NMs may be achieved in a variety of ways [4]. Note also that handy systematic procedures may be provided by an OPF algorithm which, in addition, may comply with electricity market requirements via appropriate objective functions.

## 2.6 SIME's direct products

Identification of CMs and calculation of stability margins are the main direct outcomes of SIME. Recall that they are assessed on the post-fault phase of an unstable simulation at time  $t_u$  where the instability stopping criteria (3) and corresponding OMIB angle,  $\delta_u$ , are met.

The other paramount information concerns control, i.e., stabilization conditions suggested by eq. (5).

Below we comment on these pieces of information and their direct by-products. Resulting SIME's representations will be discussed in § 2.7.

### 2.6.1 Critical Machines (CMs)

As just mentioned, at  $t_u$ , SIME identifies the CMs of concern. It also determines their "degree of advancement", in terms of the angular deviation of each CM with respect to a reference, for example, the most advanced NM.

These pieces of information will be used in various ways, discussed below.

### 2.6.2 Stability margin, $\eta$

The severity of a stability case, defined by pre-fault operating conditions and contingency scenario, including its clearing time, CT, may be measured by the corresponding stability margin.

Recall, however, that only negative margins are fully precise, since the CMs are defined on an unstable simulation. Positive margins may be computed approximately by analytical continuation (see Note of § 2.4).

### 2.6.3 Time to instability, $t_u$

The time to instability is an important parameter; it measures the degree of a contingency severity and is an interesting substitute for and complement to an unstable margin. Indeed, for very unstable cases (where the OMIB curve  $P_e$  is below  $P_m$  in the post-fault configuration), the stability margin defined by (1) does not exist. Besides, the comparison among margins corresponding to various contingencies is valid only if they involve the same group of CMs, in contrast with the time  $t_u$ . Note, however, that the comparison of times to instability is valid only when they involve the same type of instability ( $m$ -swing instability with same number  $m$ ).

### 2.6.4 Critical clearing times (CCTs)

CCTs is another way of measuring contingency severity.

According to SIME, a CCT is obtained by successive linear extrapolations between unstable simulations' margins of decreasing severity<sup>2</sup>, plus an interpolation between margins of the least unstable and a stable simulation performed for conditions close enough to the unstable one. This stable simulation is to be pursued on the entire integration period (3, 5, 10 or 15 s, as appropriate), in order to make sure that there are no multiswing instabilities; otherwise, the procedure continues until meeting a stable simulation; it then furnishes the multiswing CCT.

Note that the search procedure requires a limited number (2 to 3) of time-domain unstable simulations of short duration (plus one, stable simulation, when multiswing phenomena are of concern).

Use of CCTs is more popular in Europe than in the States where the preference is given to power limits (PLs). Note, however, that for given prefault conditions, CCT is an objective measure, computed univocally, whereas PLs may be computed in a variety of ways, yielding an undetermined number of solutions, as discussed hereafter.

### 2.6.5 Power limits (PLs)

Essentially, computation of PLs follows a pattern similar to that of CCTs: for a given contingency and its clearing time, run successive power flows and corresponding stability simulations while adjusting generation and load levels until hitting the stability boundary. *A priori*, there are many ways of changing generation and load levels during the procedure, depending on the objective sought (for example, maximum loadability conditions, maximum power flow on given set of tie-lines, homothetical variation of generation and consumption, etc). This yields a large variety of patterns, degrees of freedom and resulting solutions, which may be a drawback, when using PLs as stability measures. But it may also be an advantage when attempting to comply with electricity market needs. It is interesting to note that in all cases, SIME addresses this question in a systematic way, thanks to the consideration of CMs and NMs, see § 2.5, and section 4.

## 2.7 Basic descriptions of the OMIB dynamics

Three OMIB-based plots of a stability case are suggested in §§ 2.2 to 2.4 and described below. Their interest is suggested by Figs 2 and further discussed in § 5.1.1.

- **The OMIB swing curve** provides a synthetic description of the multimachine system behaviour and its swing curves. It allows a compression rate of  $n$ , the total number of system machines.
- **The OMIB power-angle representation** allows another type of rich interpretation-exploration of the multimachine power system behaviour; a direct application of this is the stabilization procedure of § 2.5, further explored in section 4.
- **The OMIB phase-plane representation** provides a compact way of describing the power system dynamics. It reduces the problem dimensionality from  $N$  (the total number of dynamic state variables) to 2, and thus yields a compression rate of  $N/2$ .

Of course, the above OMIB-based representations may be complemented by the traditional

<sup>2</sup>The validity of linear extrapolations relies on the general observation that stability margins vary (almost) linearly with the clearing time [7].

- **multimachine swing curves**; they are provided by the SIME-driven time-domain program up to the time to instability,  $t_u$ , for an unstable simulation, or to the return time,  $t_r$ , for a stable simulation, as appropriate.

Figures 2 summarize the aforementioned four representations in the case of a contingency applied to the Hydro-Québec power system, for two different clearing times: one above, the other below the critical clearing time yielding, respectively, an unstable and a stable simulation.

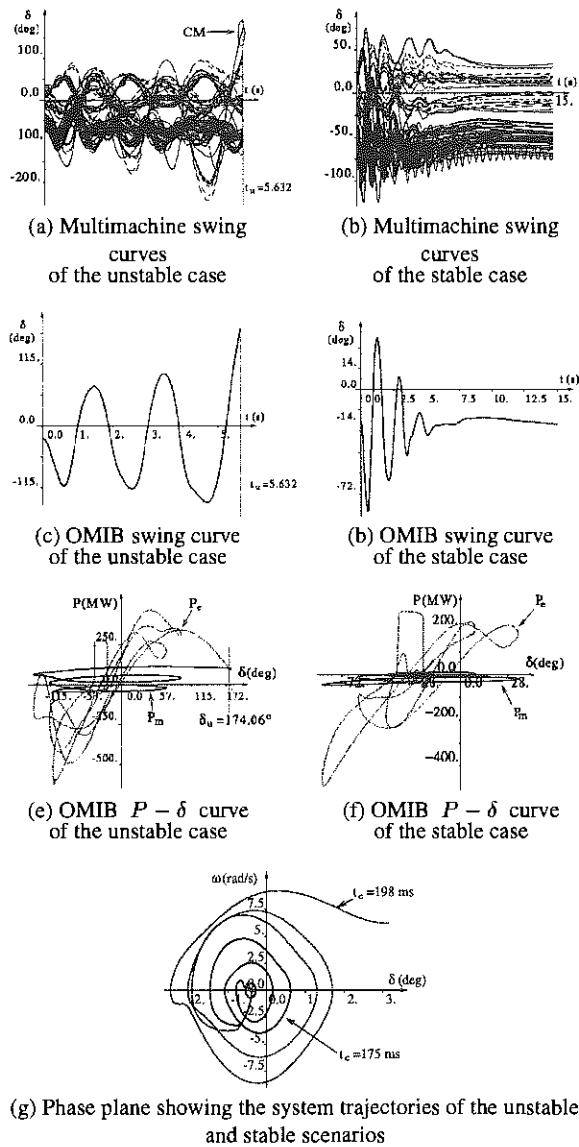


Fig. 2. Plots obtained by simulations on the Hydro-Québec power system performed with two clearing times: 198 ms (unstable scenario) and 175 ms (stable scenario). Adapted from [7]

#### Remarks

1. The time-domain program coupled with SIME to simulate the Hydro-Québec system is ST-600.

2. This system is modelled by 86 machines, which, together with the network imply over 2,000 state variables.
3. The contingency CCT was computed by SIME and by the ST-600 time-domain program, run alone; it was found that SIME is in a very good agreement with ST-600: CCT(SIME) = 175.5 ms, CCT(ST-600) = 176 ms.
4. For this system, the OMIB swing curves allow a compression rate of 86. At least as important is the fact that damping phenomena become much clearer and easier to apprehend via the OMIB swing curves than the multimachine swing curves.
5. The OMIB phase-plane representation allows here a compression rate of over 1,000. Observe how clearly are pictured the back-swing, multi-swing phenomena.

### 3 FILTRA techniques

#### 3.1 Description [2,3,7]

FILTRA (for contingency FILTERing, Ranking and Assessment) is a function which addresses the following problem: derive a contingency filtering software with good classification ability, accuracy, reliability and computational efficiency. Classification ability is meant to be the ability to discard all “uninteresting” contingencies as quickly as possible and to select-rank-assess all “interesting” contingencies, i.e., contingencies likely to threaten the system stability. Reliability is meant to be the ability of the classifier to capture all interesting contingencies. A condition for achieving computational efficiency is that, in addition, the classifier should have an as low as possible rate of “false alarms”, i.e., of contingencies which are suspected to be “interesting” and processed further, while they are not.

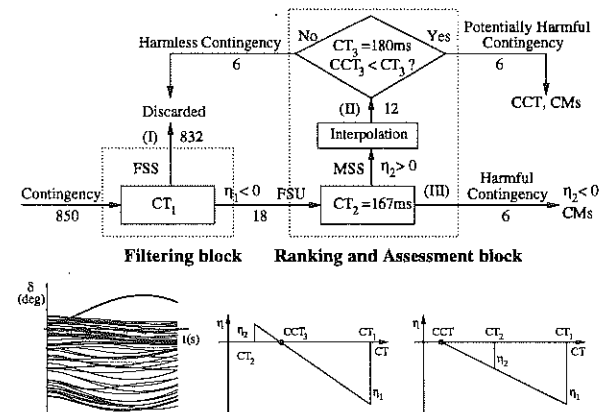


Fig. 3. FILTRA software scheme. Adapted from [7, 9].

The general organization of FILTRA is designed in [7]. The particular realization displayed in Fig. 3 comprises two blocks: one which discards all contingencies found to be “first-swing stable” (FSS) and sends the others to the second block for a finer ranking and assessment. Note that both blocks consider the fully detailed system modeling. Note also that a contingency is declared to be FSS on the basis of a double criterion, one relying on the OMIB, the other on the multimachine power system [2,3,7].

### 3.2 Illustration

The techniques of sections 3 and 4 will be illustrated on the Brazilian South-Southeast power system, comprising 56 machines, most of which modelled in detail.

In Fig. 3, the numbers correspond to simulations performed on the Brazilian power system [7, 9]. It suggests that 832 out of the 850 contingencies are found to be FSS with respect to a clearing time  $CT_1$  and are discarded outright<sup>3</sup>.

The remaining 18 contingencies, found to be “First-Swing Unstable” (FSU) with respect to  $CT_1$ , are considered to be “potentially interesting” and further explored using a clearing time  $CT_2 = 167$  ms; it was chosen on purpose quite large in order to get a significant number of harmful contingencies. The exploration is either pursued on the entire integration period (here: 4 s), or stopped as soon as an instability (first- or multi-swing) is detected. Thus:

- a contingency found to be (multi-swing) unstable for  $CT_2$  is declared Harmful (H);
- a contingency found to be (multi-swing) stable (MSS) for  $CT_2$  is declared either Potentially Harmful (PH) or Harmless (Hs) according to whether the CCT obtained by interpolating the margins computed for  $CT_1$  and  $CT_2$  is smaller or larger than a threshold,  $CT_3$ . In Fig. 3, there are 6 Hs, 6 PH and 6 H contingencies.

#### Remarks

1. The second threshold,  $CT_2$ , must be adjusted to the protection scheme delays; it is therefore contingency-dependent and may be different for different types of protection schemes and related contingencies.
2. The more interesting, i.e., the severer, a contingency, and the more detailed should be the provided description and assessment. The information proposed below takes into account this remark.

### 3.3 Types of information

#### 3.3.1 Overall contingency classification

The classification may be displayed either in a table or in a figure (similar to Fig. 3), which specifies the number of contingencies of each class (FSS, Hs, PH, or H).

#### 3.3.2 Identification and description of the “potentially interesting” contingencies

Out of the initial contingency list, the “potentially interesting” contingencies are those sent to the second block: Hs, PH and H ones.

Table 1 gives an example of the identification and description of the 18 contingencies found for the Brazilian system.

#### 3.3.3 Ranking of the Hs and PH contingencies

The ranking is made in terms of approximate critical clearing time (CCT) (whenever possible), or “time to instability”,  $t_u$ .

Table 2 summarizes the information relative to PH and Hs contingencies.

<sup>3</sup>The contingency screening of the first block portrayed in Fig. 3, summarizes the two-step procedure used in [9].

Table 1. Identification and description of Harmful, Potentially Harmful and Harmless contingencies. Adapted from [9]

| Cont. Nr | Faulted bus | Lines opened |                                | Identification |
|----------|-------------|--------------|--------------------------------|----------------|
|          |             | Circuit      | Sending node<br>Receiving node |                |
| 8        | 89          | 1            | 89 16                          | Hs             |
| 18       | 42          | 1            | 42 100                         | Hs             |
| 112      | 89          | 1            | 89 105                         | H              |
| 140      | 107         | 1            | 107 98                         | H              |
| 153      | 101         | 1            | 101 1065                       | PH             |
| 155      | 101         | 1            | 101 1068                       | PH             |
| 159      | 107         | 1            | 107 110                        | H              |
| 167      | 114         | 1            | 114 204                        | H              |
| 239      | 181         | 1            | 181 177                        | H              |
| 254      | 181         | 1            | 181 184                        | PH             |
| 256      | 181         | 1            | 181 201                        | PH             |
| 258      | 181         | 1            | 181 205                        | PH             |
| 263      | 186         | 1            | 186 182                        | H              |
| 272      | 186         | 1            | 186 187                        | PH             |
| 273      | 187         | 1            | 187 186                        | Hs             |
| 274      | 186         | 1            | 186 203                        | Hs             |
| 276      | 186         | 1            | 186 211                        | Hs             |
| 278      | 186         | 1            | 186 339                        | Hs             |

Table 2. Ranking of Potentially Harmful and Harmless contingencies. Adapted from [9]

| Cont. Nr | $CT_1$ (ms) | $\eta_1$ (rad/s) <sup>2</sup> | $\eta_2$ (rad/s) <sup>2</sup> | CCT (ms) | Nr of CMs | Ident. of CMs                     | Ranking |
|----------|-------------|-------------------------------|-------------------------------|----------|-----------|-----------------------------------|---------|
| 256      | 250         | -14.33                        | 0.30                          | 169      | 7         | 181, 184, 182, 292, 187, 186, 179 | PH      |
| 155      | 250         | -21.91                        | 1.20                          | 171      | 4         | 17, 42, 1565, 1065                | PH      |
| 254      | 250         | -52.30                        | 4.10                          | 173      | 1         | 181                               | PH      |
| 272      | 250         | -34.10                        | 3.90                          | 175      | 1         | 187                               | PH      |
| 153      | 250         | -12.62                        | 1.70                          | 177      | 4         | 17, 42, 1565, 1068                | PH      |
| 258      | 250         | -13.99                        | 2.50                          | 178      | 5         | 181, 184, 182, 292, 187           | PH      |
| 274      | 250         | -23.04                        | 4.70                          | 181      | 3         | 187, 186, 179                     | Hs      |
| 273      | 210         | -12.17                        | 5.50                          | 181      | 3         | 187, 186, 179                     | Hs      |
| 276      | 250         | -31.66                        | 8.70                          | 185      | 2         | 187, 186                          | Hs      |
| 18       | 250         | -61.48                        | 18.00                         | 186      | 1         | 42                                | Hs      |
| 278      | 250         | -21.66                        | 6.80                          | 187      | 3         | 187, 186, 179                     | Hs      |
| 8        | 240         | -13.01                        | 4.80                          | 189      | 1         | 16                                | Hs      |

#### 3.3.4 Ranking and assessment of the H contingencies

The ranking is done in terms of approximate critical clearing time, CCT, (whenever available), and of time to instability,  $t_u$ .

The assessment is done in terms of margins, CMs, and for each CM, of its “degree of advancement”, i.e. of the corresponding “electrical distance” (d) with respect to a given reference, determined at  $t_u$ . (For example, according to Table 3 and Fig. 7a, for contingency 239 the distances are determined at  $t_u = 550$  ms.)

Another important information is the approximate amount of generation necessary to be shifted from CMs to NMs in order to stabilize an H contingency. Note that, here, the total approximate amount,  $\Delta P_C$ , is distributed among the various CMs proportion-

Table 3. Ranking and Assessment of the Harmful Contingencies.  
Adapted from [9]

| 1        | 2        | 3             | 4                   | 5         | 6                 | 7               | 8                    | 9            |
|----------|----------|---------------|---------------------|-----------|-------------------|-----------------|----------------------|--------------|
| Cont. Nr | $\eta_2$ | $t_{u2}$ (ms) | Type of instability | Nr of CMs | $\Delta P_C$ (MW) | CM <sub>i</sub> | $\Delta P_{Ci}$ (MW) | $d_i$ (deg.) |
| 263      | -9.30    | 390           | +1                  | 3         | -333              | 187             | <b>-215</b>          | 92           |
|          |          |               |                     |           |                   | 186             | <b>-55</b>           | 82           |
|          |          |               |                     |           |                   | 179             | <b>-63</b>           | 55           |
| 239      | -3.49    | 550           | +1                  | 10        | -297              | 181             | <b>-115</b>          | 105          |
|          |          |               |                     |           |                   | 184             | <b>-22</b>           | 95           |
|          |          |               |                     |           |                   | 182             | <b>-46</b>           | 83           |
|          |          |               |                     |           |                   | 292             | <b>-7</b>            | 79           |
|          |          |               |                     |           |                   | 187             | <b>-55</b>           | 65           |
|          |          |               |                     |           |                   | 186             | <b>-15</b>           | 61           |
|          |          |               |                     |           |                   | 179             | <b>-24</b>           | 57           |
|          |          |               |                     |           |                   | 291             | <b>-2</b>            | 42           |
|          |          |               |                     |           |                   | 290             | <b>-6</b>            | 41           |
|          |          |               |                     |           |                   | 293             | <b>-5</b>            | 34           |
| 112      | -2.99    | 580           | +1                  | 1         | -252              | 16              | <b>-252</b>          | 64           |
| 140      | -2.46    | 605           | +1                  | 1         | -185              | 16              | <b>-185</b>          | 75           |
| 167      | -0.33    | 2020          | +2                  | 1         | -139              | 21              | <b>-139</b>          | 76           |
| 159      | -82.31   | 2805          | -3                  | 1         | +16               | 2706            | <b>-16</b>           | -13          |

ally to their corresponding product  $d_i * M_i$ , where  $M_i$  is the  $i$ -th machine's inertia coefficient. This information is displayed respectively in Columns 6 and 8 of Table 3; the meaning of bold-face values appearing in Column 8 is clarified below, in § 4.2. Note that contingency #159 creates a (multi-) back-swing instability; in such a case the generation listed in Column 8 must be shifted from NMs to CMs. Note also that contingency #239 creates inter-area instabilities.

## 4 Control techniques

### 4.1 Description

The control software mainly aims at stabilizing the harmful contingencies identified and assessed by FILTRA. It is achieved by the "Control" block, displayed by the shaded area of Fig. 4. This block processes the harmful contingencies, either each one separately or simultaneously. According to § 2.5, the stabilization consists of shifting generation from "critical machines" (CMs) to "non-critical machines" (NMs). The procedure is iterative and generally requires 2 to 3 iterations, no matter whether the contingencies are stabilized separately or simultaneously.

### 4.2 Types of information

#### 4.2.1 Detailed description of the iterative procedure

Table 4 illustrates the control procedure for stabilizing simultaneously all harmful contingencies assessed in Table 3.

The simultaneous stabilization takes advantage of the existence of CMs common to many contingencies; this suggests to choose the severest conditions among those imposed by the stabilization of the various contingencies. For example, to stabilize machine Nr 187 which is a CM for contingencies #263 and 239, one has to shift 215 MW rather than 55 MW.

This reasoning leads to the values appearing in bold in Column 8

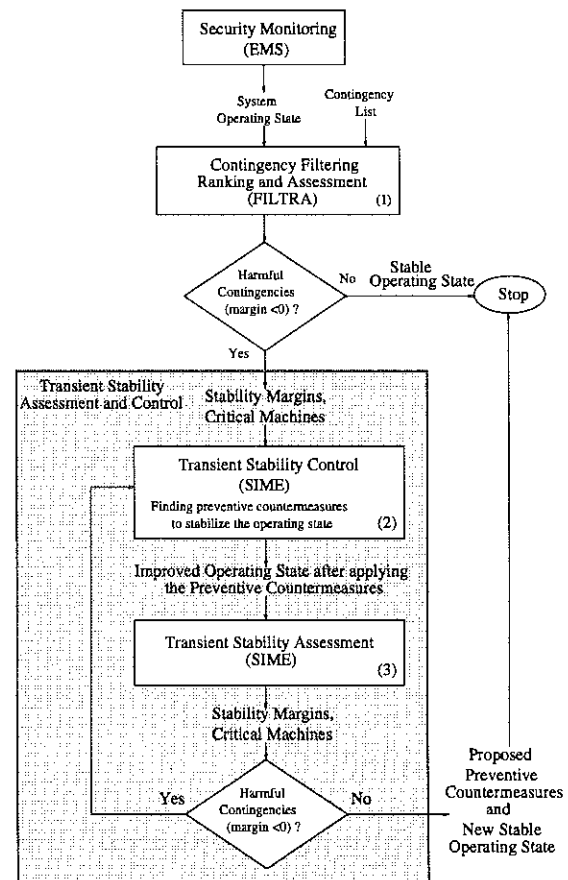


Fig. 4. Integrated real-time transient stability assessment and control software. Adapted from [7]

Table 4. Iteration #1 of the simultaneous stabilization procedure.  
Adapted from [9]

| 1                   | 2        | 3             | 4                   | 5         | 6                 | 7               | 8                    | 9            |
|---------------------|----------|---------------|---------------------|-----------|-------------------|-----------------|----------------------|--------------|
| Cont. Nr            | $\eta_2$ | $t_{u1}$ (ms) | Type of instability | Nr of CMs | $\Delta P_C$ (MW) | CM <sub>i</sub> | $\Delta P_{Ci}$ (MW) | $d_i$ (deg.) |
| <b>Iteration #1</b> |          |               |                     |           |                   |                 |                      |              |
| 263                 | 1.53     | (4000)        | (+1)                | (3)       | +47               | 187             | +30                  | –            |
|                     |          |               |                     |           |                   | 186             | +8                   | –            |
|                     |          |               |                     |           |                   | 179             | +9                   | –            |
| 239                 | 3.01     | (4000)        | (+1)                | (10)      | +248              | 181             | +97                  | –            |
|                     |          |               |                     |           |                   | 184             | +18                  | –            |
|                     |          |               |                     |           |                   | 182             | +38                  | –            |
|                     |          |               |                     |           |                   | 292             | +6                   | –            |
|                     |          |               |                     |           |                   | 187             | +46                  | –            |
|                     |          |               |                     |           |                   | 186             | +13                  | –            |
|                     |          |               |                     |           |                   | 179             | +20                  | –            |
|                     |          |               |                     |           |                   | 291             | +1                   | –            |
|                     |          |               |                     |           |                   | 293             | +4                   | –            |

of Table 3. Thus, a new load flow (LF) is performed to take into account the new generation distribution among machines. This LF is followed by a new stability run for each contingency, and new assessment of the generation to be shifted. The result is sum-

Table 5. Interface flow changes after stabilizing all harmful contingencies of Tables 3 and 4. Adapted from [9]

| Line         | kV  | Initial power flow (MW) | Final power flow (MW) | Difference (MW) |
|--------------|-----|-------------------------|-----------------------|-----------------|
| 110-109      | 765 | 2368.0                  | 2184.0                | -184            |
| 222-2559     | 230 | 178.0                   | 257.6                 | +79.6           |
| 202-2603     | 230 | 158.0                   | 206.8                 | +48.8           |
| 202-2622     | 230 | 129.0                   | 145.6                 | +16.1           |
| 303-2946     | 138 | 342.0                   | 326.8                 | -15.2           |
| 337-2608     | 138 | 248.5                   | 235.8                 | -12.7           |
| 337-2837     | 138 | 121.0                   | 111.8                 | -9.2            |
| <b>Total</b> |     | <b>3545.0</b>           | <b>3468.4</b>         | <b>-76.6</b>    |

marized in Table 4. This table shows that contingencies #263 and 239 have been slightly overstabilized (see the positive margins in Column 2, and observe in Column 3 that the time-domain simulations have been performed on the Maximum Integration Period (here, 4 s). Hence, the generation shift from some CMs could be re-adjusted, through a new iteration (#2), not reported here.

#### 4.2.2 Synthetic representation of CMs' rescheduling

An interesting synthetic representation of CMs' rescheduling is provided by bar diagrams of the generation shifting of each CM and of the total generation rescheduling after stabilizing the system. These diagrams may be drawn with respect to either each contingency stabilized individually or a set of contingencies stabilized simultaneously (as is done here).

#### 4.2.3 Information about transient stability-constrained maximum allowable power on a corridor

Table 5 summarizes the interface flow on the corridor defined by the tie-lines listed in Column 1; this corridor is transient stability-constrained by the contingencies of Tables 3 and 4.

Figures 5 and 6 show, respectively, the changes in the interface power flow for each individual tie-line and for the total set of lines after stabilizing all harmful contingencies of Tables 3 and 4.

#### 4.2.4 Multimachine swing curves

Figs 7 provide the swing curves relative to contingencies #239 and 159 of Table 3. Contingency 239 creates an instability of the inter-area mode, while under contingency 159 the system loss of synchronism is triggered during multiswing backswing oscillations.

### 4.3 Other types of information

In addition to the above direct outcomes of stabilization techniques a large variety of information may readily become available. It may be either of the multimachine type or of the OMIB type. Among many examples, one may be interested in multimachine and OMIB plots of unstable oscillations on interconnection lines or in total power system losses (before and after stabilization).

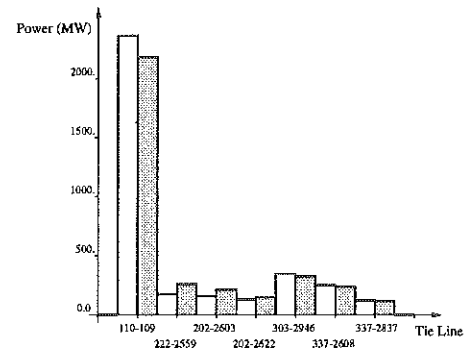


Fig. 5. Power flow on each tie-line of the interface before and after the simultaneous stabilization of all the harmful contingencies of Tables 3 and 4

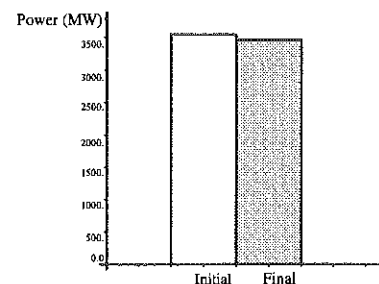


Fig. 6. Total power flow on the interface before and after the simultaneous stabilization of all the harmful contingencies of Tables 3 and 4

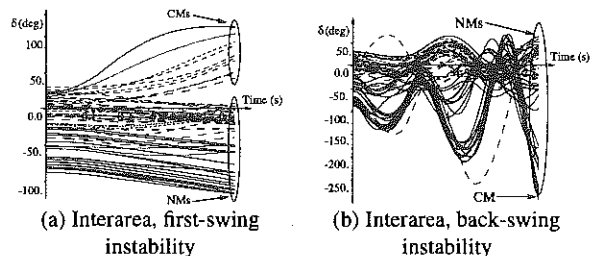


Fig. 7. Swing curves relative to contingencies #239 (a) and 159 (b) of Table 3

## 5 Functional and user-dependent classifications

### 5.1 Functional classification

#### 5.1.1 Analysis vs control type of information

Analysis type of information includes stability margins, CMs and their degree of advancement, CCTs and outputs of FILTRA. This information may be displayed in tables or figures (e.g., see Tables 1 to 3 and Fig. 3). It may be complemented and illustrated by plots, like multimachine and OMIB swing curves, OMIB  $P - \delta$  curves, OMIB phase-plane representation, inter-area oscillations (e.g., see Figs 2 and 7).

Note that, while multimachine plots are certainly of interest, OMIB representations are superior in many respects. For example, the fact that OMIB provides faithful synthetic pictures of the multimachine system behavior allows an easy visualization of

the phenomena and comparisons between stability scenarios; e.g. Figs 2 (c) and (d) provide a much clearer picture of the respective damping of two stability scenarios than the corresponding multimachine plots of Figs 2 (a) and (b). Another paramount advantage of OMIB over multimachine representations is that the amount of data to be processed (and stored) are dramatically reduced for the OMIB plots.

Control type of information has been described in §4.2. Tables 3 and 4 gather such information in a detailed way, while Figs 5 and 6 display synthetic information.

A third class of information, still to be investigated, concerns sensitivity aspects, with promising applications to analysis and control. For example, such sensitivity developments could speed up greatly procedures relative to congestion management or ATC calculations; indeed, as long as network configuration and loading conditions do not change significantly, new limit values could be obtained from the previous ones via sensitivity adjustments.

Security boundary visualization in terms of pre-contingency information (e.g., pre-contingency power generated by selected machines) is another field of investigations worth-exploring [10 to 12]. Again, sensitivity-based techniques could be useful.

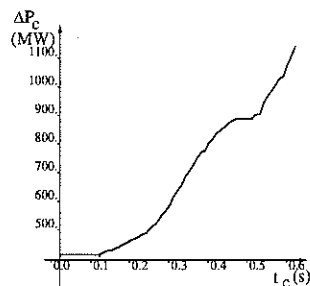


Fig. 8. Amount of controlled generation (shifting/shedding),  $\Delta P_c$ , vs control time  $t_c$ . Adapted from [13].

### 5.1.2 Detailed vs synthetic information

Detailed information, be it of the analysis or the control type, concerns the system behavior vis-a-vis a given stability scenario. Swing curves are a typical example, margins and corresponding CMs is another one of the analysis type.

Synthetic information concerns the global system behavior vis-a-vis a set of contingencies, for instance its behavior vis-a-vis all  $N - 1$  contingencies. The FILTRA structure along with the corresponding values of the various classes of contingencies is an example of synthetic information, as well as Tables 1 to 5. Yet another way of displaying synthetic information is provided by histograms, like those of Figs 5 and 6.

### 5.1.3 Post-stabilization checks

The new operating conditions resulting from a stabilization procedure should be checked in order to decide whether they still meet all types of constraints (thermal, voltage, etc.). From this point of view, too, use of an OPF algorithm would be very useful.

### 5.1.4 Higher level and global information

The above various classifications have been based on more or less “raw” information, i.e., information provided directly by the method. Compact information displaying stability regions or

global information displaying upon request various salient parameters on the one-line diagram of the power system could be of paramount importance [10,11,12]. Getting such types of information would require further developments and suggestions from end users.

### 5.1.5 User-dependent classification

So far, the SIME method has been thoroughly investigated through large-scale simulations: it has been coupled with various time-domain programs (CIRC; EUROSTAG, ETMSP; MATLAB; ST-600; SIMPOW) and tested on a large number of power systems of different structures and sizes (comprising up to hundreds of generators), and having various degrees of stress and modeling sophistication. This contributed in getting sound insight into the method’s capabilities and performances. However, the method has not yet been used by operation people, like dispatchers or system engineers. Hence, the proper selection of the information relevant to each category of users is still an open question. This paragraph aims at simply making some suggestions. In what follows, the potential users are classified in increasing amount of information needed: from the simplest synthetic information, gathered at a glance, to the most detailed and complete one.

**Dispatchers** need only a synthetic and simplified information that are able to grasp at a glance. Their main purpose is to know whether the system is in a satisfactory operating state; if not, they would like to know “how far” the system is from a secure operating state. The “distance to the stability boundary” should be expressed in terms of pre-contingency independent parameters, like generation of dedicated machines (the CMs), or compound information, like flows on important lines.

This information may be displayed in EXCEL tables informing them about the critical contingencies, the corresponding CMs, as well as histograms showing the required changes in generation shifting from CMs (from which CMs and which amount, see Figs 5 and 6). Again, security boundaries visualizing the secure/insecure regions in terms of pre-contingency generation power under given severe contingency scenarios would be extremely useful. Sensitivity analyses could be helpful along these lines.

**System operators.** For real-time TSA&C, system operators would need about the same simplified information with dispatchers, presented in synthetic ways (histograms, security boundaries and the like).

In the study mode, they might need additional information available upon request; for instance, they might want to determine how much a given harmful contingency would affect the system integrity, and how expensive the preventive actions would be.

They might also want to consider the tradeoff between preventive vs corrective action, for example, by using curves like the one drawn in Fig. 8. This curve assesses, for a particular contingency, the amount of generation power decrease in critical machines as a function of the time at which the control action is taken: prior to  $t = 0$ , this corresponds to a preventive action, for  $t \geq 0$  to a corrective one. Thus, the curve informs about the preventive vs the corrective tradeoff, and may be quite valuable for deciding whether to take an action in the preventive or the emergency mode.

**Operation planners.** Operations engineers could focus on cost-security tradeoffs, using SIME-based solutions in conjunction

with an OPF algorithm. Sensitivity would be again the core of such studies.

**R&D engineers.** Researchers may want to investigate various ways of enhancing the system stability; for example, the advantages resulting from the use of FACTS devices, or various types of emergency control devices. Again, sensitivity investigations would be the corner stone of such studies.

## 6 Concluding remarks

The SIME method exhibits features different from traditional time-domain or direct methods of the multimachine type. Its threefold membership (time-domain, direct, of the generalized single-machine equivalent type) provides it with rich, multiform and flexible information, that R&D engineers are not necessarily familiar with. To take full advantage of its possibilities, it appeared therefore useful to collect, describe and classify the resulting pieces of information. This has been the main objective of the paper.

The other objective has been an attempt to select among the wide range of information, the more appropriate for dedicated users, interested in preventive transient stability assessment and control in real time, in study mode or operational planning.

Though the above objectives have been met to a certain extent, there is still room for improvements and extensions; for example, the possibilities offered by the combination of SIME-based TSA&C techniques with an OPF algorithm could be further explored. This is specially true since power market strategies have so far ignored dynamic security aspects and their implications; therefore, a consensus about the needs is far from having been reached, since there is no feedback from the potential users of such functions. Further, no attempt was made to extract compound information and global stability assessment out of the "raw" though rich information of SIME-based TSA&C techniques. Finally, the whole bunch of sensitivity analysis aspects have still to be explored and exploited. This paper should therefore be regarded as a first attempt towards the definition and selection of the right information for the right people.

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## Trajectory sensitivity as a tool for dynamic security assessment

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### Abstract

It has been known in the literature [1] that system sensitivity increases sharply as the trajectory approaches the boundary of the region of attraction (ROA) while the trajectory does not exhibit such a sharp behavior. In this context the role of the principal singular surface (PSS) becomes significant [2]. As the trajectory evolves, the Jacobian of the flow becomes singular at a point on the PSS. Relative position of the PSS to the ROA depends on the stress level of the system under consideration. For an unstressed system the faulted trajectories will cross the PSS before they approach the ROA. For a heavily stressed system the faulted trajectories might cross the ROA before they approach the PSS. In this paper the connection between sensitivity, PSS, and ROA will be fully developed in a multi-machine context.

### Introduction

Trajectory sensitivities have been used widely in adaptive control, parameter identification, etc. [3]. Its application to different aspects of power system stability is relatively new [4, 5, 6]. Its main advantage is that it can handle any order of complexity in terms of modeling, such as differential-algebraic equations (DAE), discrete events coupled to DAE models, and hybrid systems as well. In power systems when incorporating relay dynamics or tap changing transformer models, we get a DAE model with discrete events. Trajectory sensitivity becomes a useful tool since conventional stability analysis tools are inapplicable. In this paper we restrict to power systems represented by a system of differential equations (DE) only.

In this discussion, we focus on the role of trajectory sensitivity in stability analysis of power systems. Specifically, we will try to establish a connection between trajectory sensitivity, principal singular surface (PSS), and mode of instability (MOI) or mode of disturbance (MOD). PSS was a concept introduced by Tavora and Smith [2] and later used by Podmore and Athay [7] in their classical work on transient energy function (TEF). The mode of instability concept was used in the work of Fouad and Vittal based on kinetic energy of various machines at the fault clearing time [8]. Pavella used online simulation with detailed dynamics and rank ordered the rotor angle separations to identify the critical machines before deriving a single machine equivalent (SIME) [9]. In this paper a theoretical basis to these concepts is attempted based on PSS and trajectory sensitivities at the

instant when the faulted trajectories cross the PSS. Once the MOI is established, the SIME method can also be speeded up. We illustrate the ideas with numerical examples of power systems represented by classical model.

### Theory

The  $m$ -machine classical model in relative rotor angle notation can be represented by a set of DE's as

$$\dot{\omega}_i = (-D_i \omega_i + P_i - P_{ei}) / M_i = f_i(\alpha, \omega) \quad i=1,2,\dots,m \quad (1)$$

$$\dot{\alpha}_i = \omega_i - \omega_m = f_{m+i}(\alpha, \omega) \quad i=1,2,\dots,m-1 \quad (2)$$

where  $\alpha_i = \delta_i - \delta_m$  and

$$P_i = P_{Mi} - E_i^2 G_{ii}$$

$$P_{ei} = \begin{cases} \sum_{j=1, j \neq i}^{m-1} (C_{ij} \sin \alpha_{ij} + D_{ij} \cos \alpha_{ij}) + C_{im} \sin \alpha_i + D_{im} \cos \alpha_i & i \neq m \\ \sum_{j=1}^{m-1} (-C_{mj} \sin \alpha_j + D_{mj} \cos \alpha_j) & i = m \end{cases}$$

$$\alpha_{ij} = \alpha_i - \alpha_j$$

The other notation is standard in the literature and the  $m^{\text{th}}$ -machine is taken as the reference machine. The faulted and post-fault systems have the same structure except for different values of  $C_{ij}$  and  $D_{ij}$ .

Equations (1) and (2) can be easily written in state space form as

$$\dot{x} = f(x, \lambda) \quad (3)$$

where  $x = [x_1 \dots x_{2m-1}]' = [\omega_1 \dots \omega_m \alpha_1 \dots \alpha_{m-1}]'$  and  $\lambda$  is a parameter of interest such as mechanical input power, line reactance, clearing time, etc. In this paper we choose  $\lambda$  to be mechanical input power.

The sensitivity model system is given as

$$\dot{x}_\lambda = f_x x_\lambda + f_\lambda, \quad x_\lambda(0) = 0 \quad (4)$$



where  $x_\lambda = \frac{\partial x}{\partial \lambda}$ ,  $f_x = \frac{\partial f}{\partial x}$ , and  $f_\lambda = \frac{\partial f}{\partial \lambda}$

Note that  $f_x$  and  $f_\lambda$  are time varying matrices and are evaluated along the trajectories.

The entries of the Jacobian  $f_x$  are calculated as follows for  $i=1, \dots, m$ ;  $j=1, \dots, m$ ;  $k=1, \dots, m-1$ ;  $n=1, \dots, m-1$

$$\frac{\partial f_i}{\partial x_j} = \begin{cases} -D_i / M_i & \text{if } i = j \\ 0 & \text{if } i \neq j \end{cases}$$

$$\frac{\partial f_i}{\partial x_{m+k}} = \begin{cases} -[\sum_{j=1}^{m-1} (C_{ij} \cos \alpha_{ij} - D_{ij} \sin \alpha_{ij}) + C_{im} \cos \alpha_i - D_{im} \sin \alpha_i] / M_i & \text{if } i = k, i \neq m \\ -[C_{ik} \cos \alpha_{ik} + D_{ik} \sin \alpha_{ik}] / M_i & \text{if } i \neq k, i \neq m \\ -[C_{ik} \cos \alpha_{ik} - D_{ik} \sin \alpha_{ik}] / M_i & \text{if } i = m \end{cases}$$

$$\frac{\partial f_{m+k}}{\partial x_j} = \begin{cases} 1 & \text{if } j = k, j \neq m \\ 0 & \text{if } j \neq k, j \neq m \\ -1 & \text{if } j = m \end{cases}$$

$$\frac{\partial f_{m+k}}{\partial x_{m+n}} = 0$$

Consider the Jacobian of (3) in the region  $-\pi < \alpha_i < \pi$ . It is the same as the function  $f_x$  in (4). The singular surface is defined as a set of points  $x$  such that the Jacobian evaluated at these points is singular. There is a family of singular surfaces. The surface containing the origin is called the principal singular surface. One can define the singular surfaces for both the faulted and post-fault systems. But for a larger system there is not much difference between the two since the values  $C_{ij}$  and  $D_{ij}$  differ very slightly for the two systems. Hence, we consider only the PSS of the post-fault system in this paper. As the trajectories evolve with time, they approach a point on the PSS where the Jacobian becomes singular, i.e., one eigenvalue of the Jacobian approaches the imaginary axis. After crossing the PSS we expect that the sensitivities will expand since the Jacobian has an eigenvalue in the right half plane. The machine corresponding to highest sensitivity at the exit point will become unstable ultimately if the fault was sustained longer than the critical clearing time. Thus we develop an early test for detecting the MOI.

### Numerical examples

A 3-machine, 9-bus [10] and a 10-machine, 39 bus [11] power systems are used as numerical examples to illustrate the idea discussed in the previous section. Self-clearing fault is used in all simulations. The '+' signs in the trajectories and sensitivities mark the points where the trajectories cross the PSS. The first sign signals an eigenvalue crossing the imaginary axis from the left and the second one signaling the

crossing in the opposite direction. These also correspond to the trajectory in the  $\alpha$ -plane leaving and entering the PSS.

#### The 3-machine, 9-bus system

In this system machine 1 is chosen as reference since it has largest inertia. Re-numbering can be done to be consistent with the theory. In this process we define  $\alpha_1 = \delta_3 - \delta_1$  and  $\alpha_2 = \delta_2 - \delta_1$ . The PSS of this system in  $(\alpha_1 - \alpha_2)$ -plane is shown in Fig. 1. A fault was simulated at bus 7 of this system and the simulation results of the relative angles and their sensitivities for this stable case are shown in Fig. 2 and Fig. 3 respectively.

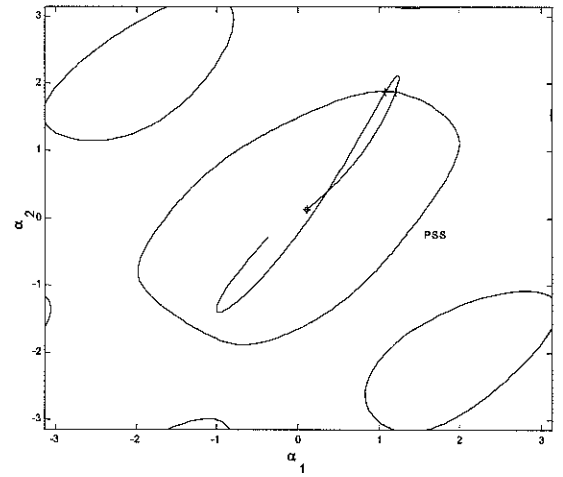


Fig. 1. The singular surfaces of the 3-machine system (stable system)

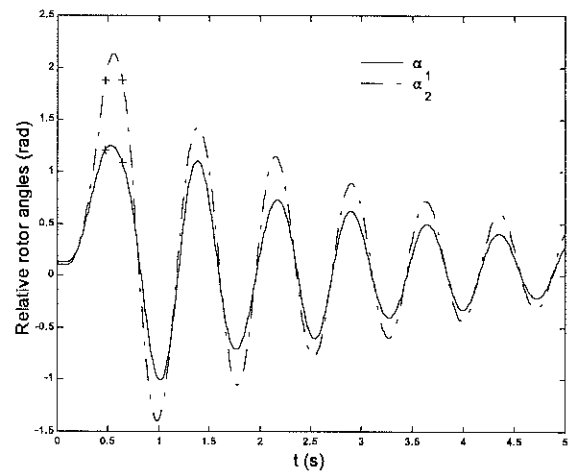


Fig. 2. Relative rotor angles

From Fig. 3 we see that sensitivity of machine 2 increases significantly in the interval 0-0.5 s whereas the sensitivity of machine 3 does not change. Thus we can conclude that machine 2 is potentially the unstable one. This was verified by successively increasing the clearing time in the simulations.

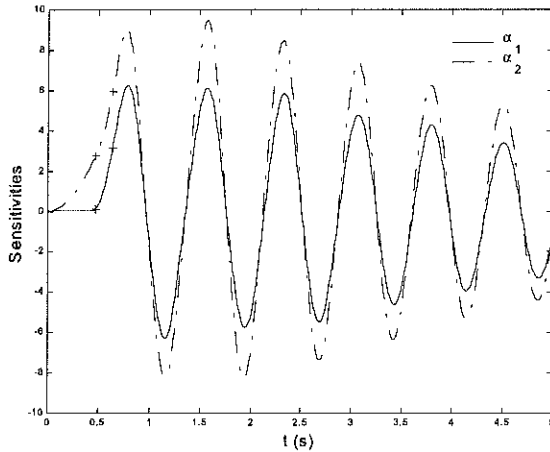


Fig. 3. Sensitivities of relative rotor angles

#### The 10-machine, 39-bus system

The structure of the Jacobian for this system is as follows

$$J = \begin{bmatrix} -D_1/M_1 & 0 & \cdots & 0 & J_{1,11} & \cdots & J_{1,19} \\ 0 & \ddots & \ddots & \vdots & \vdots & \ddots & \vdots \\ \vdots & \vdots & \ddots & \vdots & \vdots & \ddots & \vdots \\ 0 & \cdots & -D_{10}/M_{10} & J_{10,11} & \cdots & J_{10,19} \\ 1 & 0 & \cdots & -1 & 0 & \cdots & 0 \\ 0 & 1 & 0 & \cdots & -1 & \ddots & \vdots \\ \vdots & \vdots & \ddots & \vdots & \vdots & \ddots & \vdots \\ 0 & \cdots & 1 & -1 & 0 & \cdots & 0 \end{bmatrix}$$

where the entries of the Jacobian are given in the theory section

Machine 10 is chosen as reference for this system. A fault was simulated at bus 27 and cleared with  $t_{cl} < t_{cr}$  so that the system is stable. By monitoring the PSS crossing along the trajectories, it was found that the machine 9 was potentially the unstable machine as shown in Fig. 4. The early test of looking at sensitivities in the 0-0.3 s range reveals that machine 9 is unstable if the fault is not cleared soon enough. Successively increasing  $t_{cl}$  in simulations, the result is as expected as shown in Fig. 5 for  $t_{cl}$  slightly greater than  $t_{cr}$ .

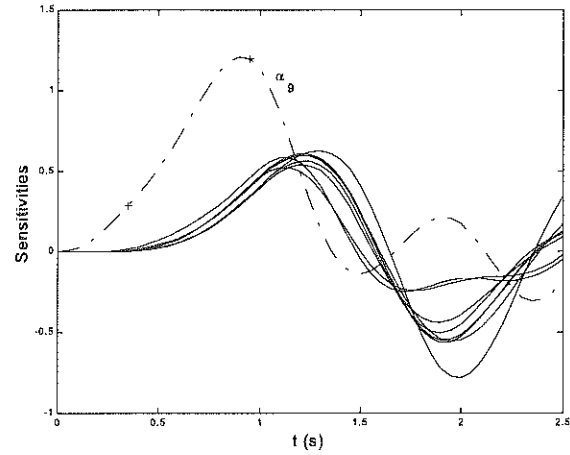


Fig. 4. Sensitivities of relative rotor angles (stable case)

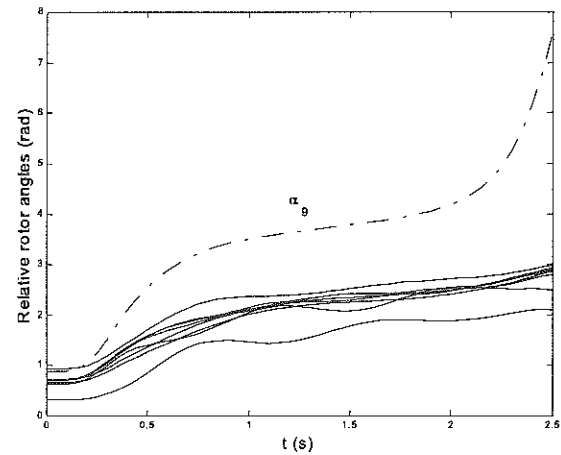


Fig. 5. Relative rotor angles (unstable case)

#### Discussion and future work

As pointed out earlier, one of the possible drawbacks of the technique may lie in the fact that the faulted trajectory may cross the ROA before it crosses the PSS. This may also be verified from a single machine infinite bus (SMIB) analysis or the equal area criterion since the PSS corresponds to the peak of the power angle curve  $\delta = \pi/2$  whereas the u.e.p. corresponds to  $\pi - \delta_s$ . A detailed SMIB analysis is not included here. It may also be noted that the PSS in a multi-machine case corresponds to the case where the Hessian of the potential energy function becomes singular. Hence there is a rich connection between the stability theory and sensitivity

theory as pointed out by Tomovic [1]. He has intuitively stated trajectory sensitivity as a tool for stability in “finite time interval” whereas Lyapunov stability theory is for “infinite time interval”. This key concept may be of use in complex stability phenomena in power systems such as oscillatory instability which currently is studied in a linearized setting. Extension to DAE systems is tempting and we may need a new notion of PSS based on generalized eigenvalues. Finally, since dynamic voltage collapse is considered to be a slower phenomenon than the angle stability, the PSS may have some applications.

The trajectory sensitivity approach in DAE setting has been used to compute  $t_{cr}$  by computing sensitivities at two time points and then extrapolating them. Efforts are being done to compute the trajectory sensitivities of line flows with respect to generated power which will be of use in dynamic security assessment for a restructured environment.

### Conclusion

The concept of PSS is studied and applied to detect an early indication of mode of instability. Also, the trajectory sensitivities are used to suggest a potentially unstable machine after MOI is established. We also know that the trajectory sensitivities and system dynamics are well correlated. Therefore, by monitoring the PSS crossing, trajectory sensitivities, and the MOI, we will have a good knowledge about the system stability.

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# Study on Stability Estimation of Multi-machine Power System and Generator Shedding by Using Artificial Neural Network

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**Keywords:** Power System, Transient Stability, Liapunov Function, Neural Network, Generator Shedding

## 1. Introduction

In recent years, the power system becomes large and complicated, the power plants of big scale establish in the distant place from the center of loads, and power transmission line become a long distance. Under such situations, the step out is leaded depending on the faults that are worried by the spreading of the power failure in the large scale. Therefore, for the stable and reliable power supply, the suitable measure against stabilization such as generator shedding is required when the power failure happens. When the generator shedding is carried out, it is necessary to estimate correctly the stability of the power system after the fault occurrence. Moreover, when it is estimated that it is unstable, it is necessary to estimate whether the power system after carrying out generator shedding is stable or not. But it is necessary for calculation of transient stability to solve a simultaneous differential equation every minute time and it needs enormous calculation time. So in case of actual operation, the above-mentioned terms become some problems. Therefore, when demanding high-speed calculation such as the case of considering on-line calculation, the way of using the neural network is effective. Until now, the stability estimations by using the neural network have been variously examined. When the power angle and angular velocity are used as input information for the stability estimation, the learning of the network becomes difficult, because the number of the units increases in the big scale power system.

The authors have carried out the simulations about transient stability after the fault line clearance by simplification from multi-machine system to one-machine infinite bus system[1]. As a result, it was confirmed that a constant stable area was obtained irrespective of the state of loads and duration time of the fault by using Liapunov Function method. Moreover, stability estimations

after the fault line clearance were carried out by the stability estimation system of which input information was the Liapunov Function. As a result, it was confirmed that good estimated results were obtained. In this paper, the estimation method of transient stability after generator shedding, namely using the estimation system by using the neural network of which input are the values of the Liapunov Function at the fault line clearance is proposed. Then it was confirmed that the proposed method was effective by the simulations of generator shedding for the IEEJ WEST 10-machine model system[2].

## 2. Transient stability area assumed generator shedding

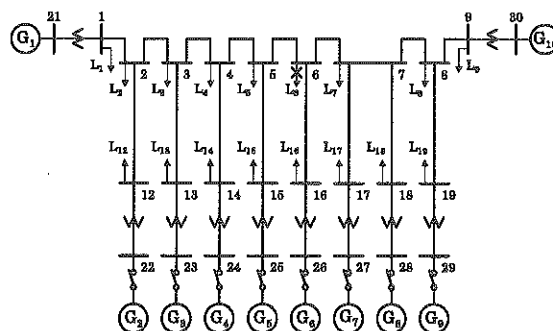


Fig1. IEEJ WEST 10-machine model system

The simulations of transient stability at generator shedding were carried out for the IEEJ WEST 10-machine model system shown in Fig.1. The case when the load L6 connected to the center of the system was eternally dropped out in connection with the fault was assumed. When the shedding generator assumed G9, the simulations of generator shedding were carried out. Then it was assumed that the shedding generator was separated from the system after 0.05s from the fault line clearance.

The values of the Liapunov Function,  $V_{ksw}$

and  $V_{psw}$ , at the fault line clearance were obtained. The kinetic energy  $E_{ksw}$  and the potential energy  $E_{psw}$  were calculated as the following equations. Moreover, the values of the Liapunov Function at the unstable equilibrium point of the system show as  $V_{max}$ .

$$E_{ksw} = \frac{V_{ksw}}{V_{max}} \quad (1)$$

$$E_{psw} = \frac{V_{psw}}{V_{max}} \quad (2)$$

The state of loads before the fault were changed from 70% to 95% every 2.5% and duration times of the fault were changed every

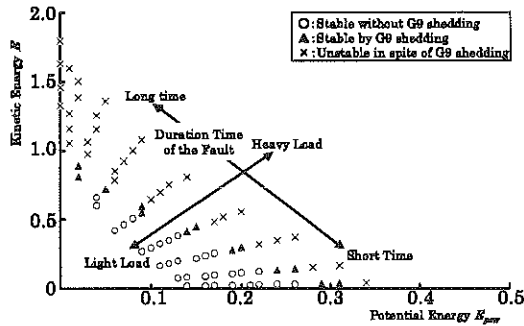


Fig2. Simulation results of transient stability after G9 shedding

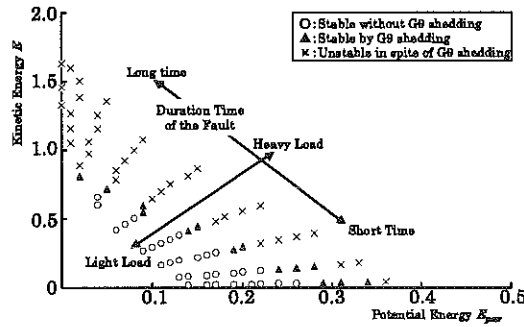


Fig3. Simulation results of transient stability after G8 shedding

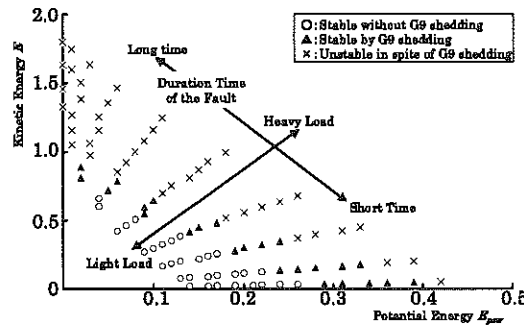


Fig4. Simulation results of transient stability after G7 shedding

0.05s. The simulation results of transient stability shown with the kinetic energy  $E_{ksw}$  and the potential energy  $E_{psw}$  at the fault line clearance are shown in Fig.2. In this figure, the cases when the system after the fault line clearance is stable without G9 shedding are shown as "O", the cases when the system becomes stable by G9 shedding are shown as "A", the cases when the system is unstable in spite of G9 shedding are shown as "X". As shown in the above results, the area where the system can be stabilized by G9 shedding is shown with the values of  $E_{ksw}$  and  $E_{psw}$ .

The simulation results of generator shedding are shown in Fig.3 and Fig.4 when the shedding generator assumes G8 or G7. Also as shown in these results, the area where the system can be stabilized by G8 or G7 shedding is shown with the values of  $E_{ksw}$  and  $E_{psw}$  the same as the case when G9 is assumed to be the shedding generator.

### 3. Transient stability estimation assumed generator shedding

As shown in the results of the preceding chapter, the area where the system can be stabilized by generator shedding is shown with the values of  $E_{ksw}$  and  $E_{psw}$ . So the estimation system of transient stability is constructed as shown in Fig.5. This estimation system is constructed with three-layer type neural network. Units of the input layer are the values of energy function  $E_{ksw}$  and  $E_{psw}$  at the fault line clearance, a unit of the output layer is corresponded to the value of stability estimation after generator shedding. Then the value of stability estimation is corresponded to "0" when the system is stable without generator shedding, the value is corresponded to "0.5" when the system becomes stable by generator shedding, the value is corresponded to "1" when the system is unstable in spite of generator shedding. One hidden layer is set and the number of the units is four.

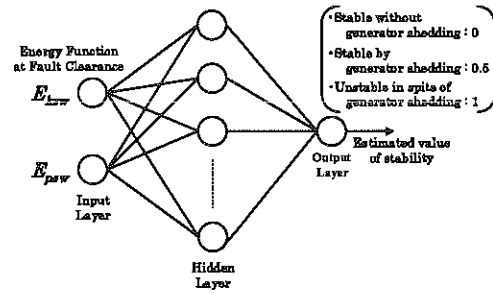


Fig5. Estimation system of transient stability after generator shedding

The estimated results of transient stability that the shedding generator is assumed G9 are shown in Fig.6. In the cases that the system after the fault line clearance is stable without G9 shedding: generator shedding must not be carried out, all of the outputs of the stability estimation show almost 0, and the estimated results of these cases are good. In the cases that the system is unstable in spite of G9 shedding, all of the outputs show almost 1. In the cases that the system becomes stable by G9 shedding, the stability estimations succeed by four cases among six cases when it is judged that the outputs of the estimation system shows 0.3-0.7 as a success. The cases that were failed in the stability estimation

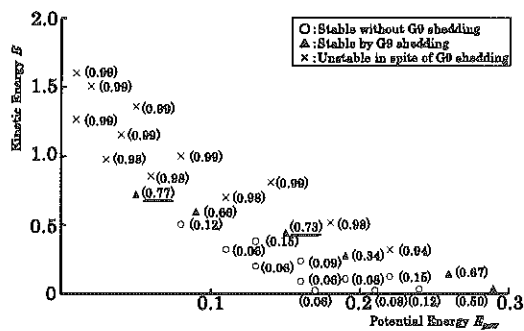


Fig6. Estimation results of transient stability after G9 shedding.

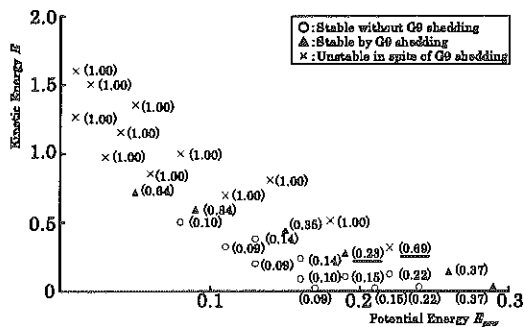


Fig7. Estimation results of transient stability after G8 shedding.

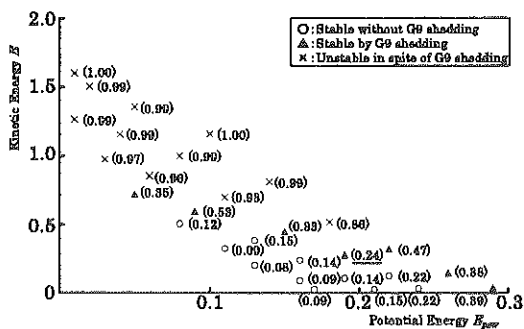


Fig8. Estimation results of transient stability after G7 shedding.

are shown with an underline in Fig.6.

The estimated results of transient stability that the shedding generator is assumed G8 are shown in Fig.7. In the cases that the system after the fault line clearance is stable without G8 shedding: generator shedding must not be carried out, all of the outputs of the stability estimation show almost 0, and the estimated results of these cases are good. In the cases that the system is unstable in spite of G8 shedding, all of the outputs show 1 except for one case. In the cases that the system becomes stable by G8 shedding, the stability estimations succeed by five cases among six cases in case of the same criterion as the above-mentioned judgment.

The estimated results of transient stability that the shedding generator is assumed G7 are shown in Fig.8. The outputs of the stability estimation show almost 0 in cases of the system after the fault line clearance is stable without G7 shedding, the outputs of the stability estimation show almost 1 in cases of the system is unstable in spite of G7 shedding, both show the good estimated results. In the cases that the system becomes stable by G7 shedding, the stability estimations succeed by six cases among seven cases in case of the same criterion as the above-mentioned judgment.

As shown in the above results, comparatively good estimated results are obtained when the estimation system of transient stability that is shown in Fig.5 is applied to the model system that is assumed generator shedding.

#### 4. Conclusion

The estimation system of transient stability at generator shedding was constructed, and the simulations of transient stability estimation after generator shedding were carried out for the IEEJ standard model system. Then it was confirmed that comparatively good estimated results were obtained. But the estimation system proposed in this paper must be prepared as the same number as assumed shedding generators; they have to be applied one by one at the fault occurrence. After this, it is necessary to improve the estimation system, namely a number of applying estimation systems at the time of one fault is one or about 2-3 systems.

## Appendix

### A. Energy function

All generators of multi-machine system are classified into a stable group S and an unstable group U. They are simplified to two-machine system of the following equations that are shown by the center of angle concept, which is about the swing of each generator in the two groups[3][4].

$$M_s \frac{d^2 \delta_s}{dt^2} = \sum_{k \in S} (P_{mk} - P_{ek}) \quad (\forall k \in S) \quad (A1)$$

$$M_u \frac{d^2 \delta_u}{dt^2} = \sum_{l \in U} (P_{ml} - P_{el}) \quad (\forall l \in U) \quad (A2)$$

And then, it defines a relative phase difference from the set U on the set S as  $\delta$ , a simple model which is shown by the following one-machine infinite bus system is obtained.

$$M \frac{d^2 \delta}{dt^2} = P_m - \{P_c + P_e \sin(\delta - \nu)\} \\ (\delta = \delta_s - \delta_u) \quad (A3)$$

The Liapunov Function to this simple model is shown as the following equations.

$$V(\delta, \omega) = \frac{\omega^2}{2} + \frac{1}{M} [P_{nm} \{\sin(\delta - \delta_s) - (\delta - \delta_s)\} \\ + \sqrt{P_{em}^2 - P_{nm}^2} \{1 - \cos(\delta - \delta_s)\}] \\ = V_k \text{ (kinetic energy)} + \\ V_p \text{ (potential energy)} \quad (A4)$$

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# Stability of Combined Cycle Power Plant for Frequency Drop

Kazuhiro Baba Naoto Kakimoto (Kyoto University)

**Abstract** - Combined cycle power plant which combines gas turbine and steam turbine can achieve high energy efficiency. Many combined cycle plants have been installed in the world. However, a large-scale blackout occurred in Malaysia in 1996. Combined cycle and gas turbine plants sequentially tripped out. The cause of this chain trip was thought to be a system frequency drop. Considering these backgrounds, it is important to study dynamic behavior of combined cycle plants. Several dynamic models of combined cycle plant have been proposed. In our analysis, we use some of them and build a model for a single-shaft combined cycle plant. We execute numerical simulations to see how the combined cycle behaves when the system frequency drops. The mechanism and the countermeasure of the plant trip-out are explained in this paper.

**Keywords** - combined cycle power plant, plant trip-out, temperature control, air control, fuel control

## 1. INTRODUCTION

Combined cycle power plant which combines gas turbine and steam turbine can achieve high energy efficiency. The plant mainly consists of a gas turbine, a waste heat recovery boiler and a steam turbine. This type of plant has high energy efficiency which exceeds 50%. Many combined cycle plants have been installed in JAPAN. Total capacity is about 20,000MW. However, a large blackout occurred in Malaysia. Combined cycle and gas turbine plants sequentially tripped out. The total generation loss was 5,760MW. The cause of this chain trip was thought to be a system frequency drop. Considering the blackout in Malaysia, it is important to study dynamic behavior of the combined cycle plants.

Several dynamic models of the combined cycle plant have been proposed[1-5]. In our analysis, we use some of them and build a model for a single-shaft combined cycle plant. We execute numerical simulations to see how the combined cycle plant behaves when the system frequency drops.

## 2. COMBINED CYCLE MODEL

### A. Single-Shaft Combined Cycle Generator

In our study, we deal with a 1,100°C class single-shaft combined cycle plant whose rated power output is 160 MW. Figure 1 shows the configuration of the combined cycle plant. The plant consists of a compressor, combustor, gas turbine, waste heat recovery boiler, steam turbine and a generator. The air compressed by the compressor is sent to the combustor. In the combustor, air and fuel are turned

into flue gas with high temperature and high pressure. The gas turbine is activated by the energy of the flue gas. The energy of the exhaust gas is collected by the waste heat recovery boiler, and it activates the steam turbine. Plant power output is the sum of the gas turbine and the steam turbine power output. The gas turbine produces about two thirds of the total power output, and the steam turbine produces the rest.

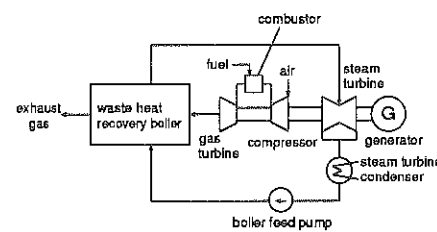


Fig. 1. Single-shaft combined cycle plant.

### B. Gas Turbine and Steam Turbine

Figure 2 shows the thermal cycle of the gas turbine. Process 1 to 2 is an adiabatic compression of the air by the compressor. Process 2 to 3 is an isobaric heating of the compressed air by the combustor. Process 3 to 4 is an adiabatic expansion of the flue gas. Process 4 to 1 is an isobaric radiation of the exhaust gas.

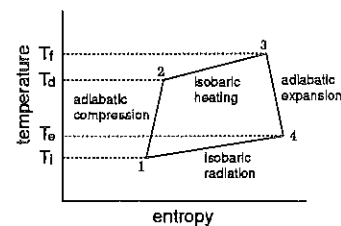


Fig. 2. Gas turbine cycle.

(1) **Compressor** The compressor compresses air by using the mechanical energy of the turbine. If air is assumed to change adiabatically, compressor outlet temperature  $T_d$  is described as follows:

$$T_d = T_i \left( 1 + \frac{x-1}{\eta_c} \right) \quad (1)$$

$$x = (P_r W)^{\frac{\gamma-1}{\gamma}} \quad (2)$$

where  $T_i$  is compressor inlet temperature and equals to the ambient temperature,  $W$  is air flow,  $\eta_c$  is compressor



efficiency,  $\alpha$  is compressor thermal ratio,  $P_c$  is compressor pressure ratio,  $\gamma$  is ratio of specific heat.

(2) Combustor The combustor turns air and fuel into flue gas with high temperature and high pressure. The gas flow is assumed to be same as air flow. Gas turbine inlet temperature  $T_f$  is described as follows:

$$T_f = T_d + \frac{W_f}{W} K_2 \quad (3)$$

where  $W_f$  is fuel flow,  $K_2$  is coefficient of combustor temperature.

(3) Gas turbine The energy of the flue gas activates the gas turbine, and the pressure of the flue gas is decreased through adiabatic expansion process. Gas turbine exhaust temperature  $T_e$  is described as follows:

$$T_e = T_f \left[ 1 - \left( 1 - \frac{1}{\alpha} \right) \eta_t \right] \quad (4)$$

where  $\eta_t$  is turbine efficiency.

The work of the flue gas through adiabatic expansion becomes gas turbine mechanical power  $P_{mg}$ . In order to compress air by the compressor, driving power is required. Gas turbine power output  $P_g$  is the difference between gas turbine mechanical power  $P_{mg}$  and compressor driving power  $P_c$ .

$$P_{mg} = K_0 (T_f - T_e) W \quad (5)$$

$$P_c = K_0 (T_d - T_i) W \quad (6)$$

$$P_g = P_{mg} - P_c \quad (7)$$

where  $K_0$  is coefficient of gas turbine power output.

(4) Steam turbine Steam turbine power output is determined by the gas turbine exhaust temperature  $T_e$  and the gas flow  $W$ .

$$P_s = K_1 T_e W \quad (8)$$

where  $K_1$  is coefficient of steam turbine power output. In usual operation, the steam turbine power output is not controlled.

### C. Plant Control System

Control systems of the combined cycle plant are shown in Fig.3. There are four control units in a plant; load/speed control, temperature control, fuel control and air control.

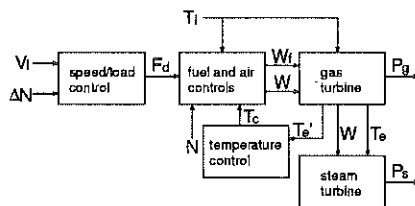


Fig. 3. Control systems of combined cycle.

(1) Speed/load control Fig.4 shows the speed/load control unit. A fuel signal  $F_d$  is determined by a load demand  $V_i$  and a turbine speed deviation  $\Delta N$ .

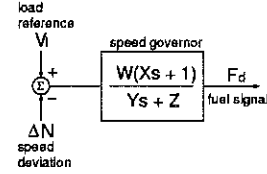


Fig. 4. Speed/load control unit.

(2) Temperature control Fig.5 shows the temperature control unit. Temperature is restricted by this unit not to injure the gas turbine. The measured exhaust temperature  $T_e$  is compared with the reference temperature  $T_r$ . The output is a temperature control signal  $T_c$ .

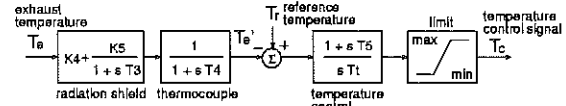


Fig. 5. GT temperature control unit.

(3) Fuel control Fig.6 shows the fuel control unit. In this unit, the fuel signal is compared with the temperature control signal. The smaller signal is selected at LVG (Least Value Gear) and determines the fuel flow  $W_f$ . Controlled fuel is sent to the combustor.

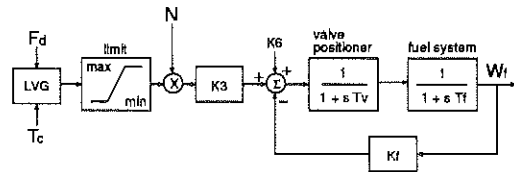


Fig. 6. Fuel control unit.

(4) Air control Air flow is controlled in accordance with the fuel signal, so as to attain the desired gas turbine exhaust temperature.

Fig.7 shows the relation between the fuel flow  $W_f$ , air flow  $W$ , exhaust temperature  $T_e$ , reference temperature  $T_r$ , gas turbine inlet temperature  $T_f$  and the combined cycle power output  $P_m$ .

Gas turbine exhaust temperature is kept high during the partial load operation by decreasing the air flow. This operation makes it easy to collect the thermal energy in the waste heat recovery boiler. Air flow is adjusted by the compressor inlet guide vane (IGV). The amount of the adjustable air flow is about 30 % of the rated air flow. Adjusting speed of the air flow is slower than that of fuel flow, and the air flow changes 2% of the rated air flow per second. The air flow is proportional to turbine speed  $N$ . Fig.8 shows the air control unit.

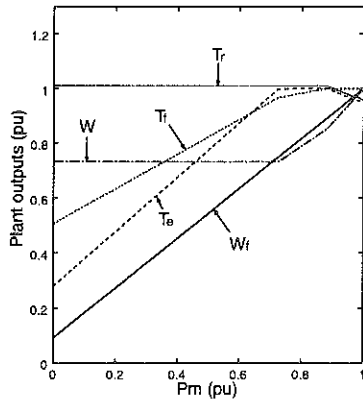


Fig. 7. Heatbalance.

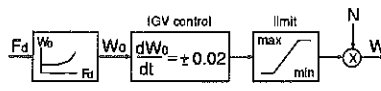


Fig. 8. Air control unit.

#### D. Combined Cycle Output Unit

The power output unit is shown in fig.9. Plant power output  $P_m$  is the summary of the gas turbine power output  $P_g$  and the steam turbine power output  $P_s$ . Plant power output is proportional to the turbine speed  $N$ .

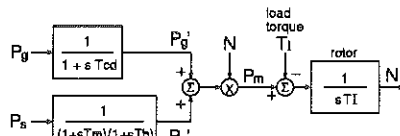


Fig. 9. Power output unit.

### 3. ANALYSIS OF PLANT TRIP-OUT

When the large-scale blackout occurred in Malaysia, combined cycle and gas turbine plants sequentially tripped out. The cause of this chain trip is thought to be a system frequency drop. In this section, we investigate the response for frequency drop and analyze the trip-out phenomenon. Plant parameters are listed in the appendix.

#### A. Response for Frequency Drop

In order to investigate the trip-out phenomenon, we make frequency drop simulations among a power system which consists of a combined cycle plant and a load. We drop the system frequency to 0.97 pu at  $T = 0$  (sec), while the combined cycle plant is under (a) full load operation and (b) 85% load operation, and check the response of some plant outputs.

Figure 10 shows the result of case (a). After frequency drops at  $T = 0$  (sec), the fuel flow  $W_f$  is increased so as to increase the gas turbine power output  $P_m$ . The increased power output recovers the turbine speed  $N$  to 1 pu. Figure 11 shows the result of case (b). Each plant output shows a response similar to those of case (a) just after the frequency drop. However the turbine speed decreases and the plant trips-out finally.

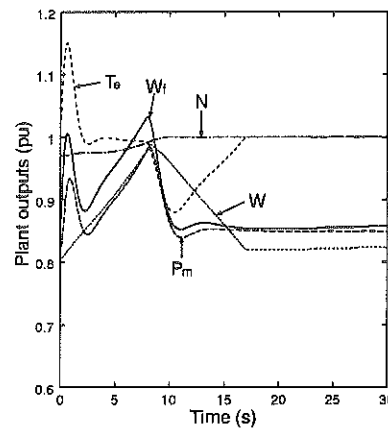


Fig. 10. Response for frequency drop (85% load).

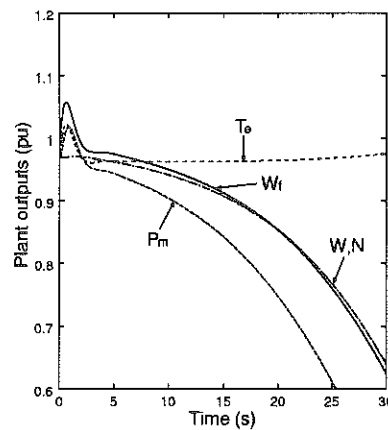
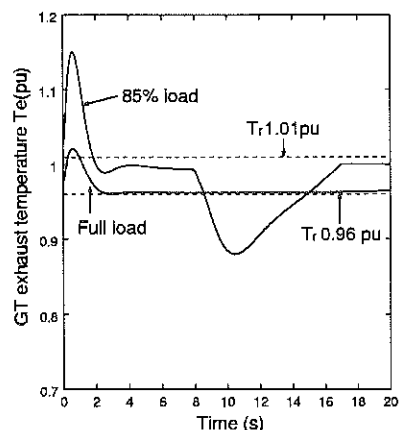


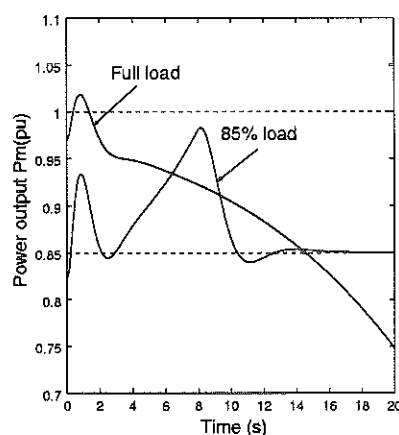
Fig. 11. Response for frequency drop (full load).

#### B. Analysis of Plant Outputs

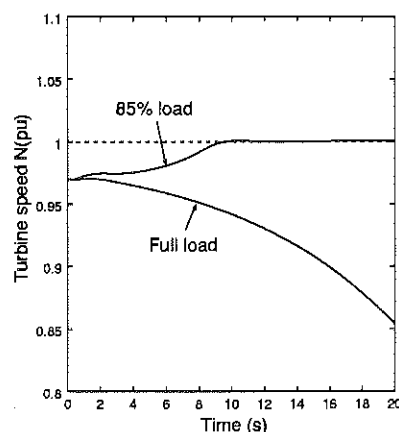
In this section we consider the mechanism of plant trip-out through the response of plant outputs. If the system frequency is decreased (hence the turbine speed  $N$  is decreased), fuel flow  $W_f$  is increased to recover the dropped frequency (Fig.10, 11). However, exhaust temperature  $T_e$  is increased at the same time, and it exceeds the reference temperature  $T_r$ . Therefore the temperature control



(a) exhaust temperature



(b) power output



(c) turbine speed

Fig. 12. Analysis of plant outputs.

restricts the fuel flow. Fig. 12 (a) shows the response of exhaust temperature  $T_e$ . In the case of 85% load operation, exhaust temperature gets lower than the reference temperature ( $T_r = 1.01$  pu). On the other hand, the exhaust temperature keeps on exceeding the reference temperature ( $T_r = 0.96$  pu), when the plant is under the full load operation. This difference is caused by the air flow. The air flow is adjusted by the IGV in reference to the fuel signal  $F_d$ . In the case of 85% load operation, air flow is increased due to the rise of fuel signal. Therefore, the exhaust temperature gets lower. However, in the case of full load operation, IGV is fully opened and the air flow would not increase. Hence, an increase of the fuel flow raises the GT exhaust temperature.

Fig. 12 (b) shows the response of the plant power output  $P_m$ . In the case of 85% load operation, even after the fuel flow is restricted, the plant power output is greater than the demanded load 0.85 pu. Therefore the turbine speed recovers, as is shown in fig. 12 (c). Finally, the power output  $P_m$  and the exhaust temperature  $T_e$  are decreased to their original values. On the other hand, in the case of full load operation, the power output gets smaller than the demanded load. Hence the turbine speed does not recover and it keeps on dropping.

### C. Plant Power Output and Trip-out Frequency

In this section, we investigate the plant trip-out frequency under several load conditions.

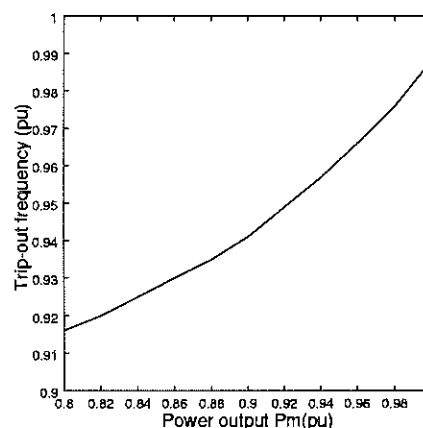


Fig. 13. Plant power output and trip-out frequency.

The result is shown in fig. 13. As the load gets larger, the trip-out frequency gets higher and the plant becomes unstable. This is because the upper margin of the air flow gets smaller. If the system frequency drops, air flow and fuel flow increases at the same time. therefore exhaust temperature is kept within a limit. However, if the upper margin of the air flow is small, exhaust temperature rises easily, when the fuel flow increases. If the exhaust temperature

gets higher than a reference temperature, temperature control acts so as to decrease the fuel flow. As a result, the turbine can not obtain enough power to accelerate itself, and the plant trips out.

#### D. IGV Speed and Trip-out Frequency

The adjusting speed of air flow is slower than that of fuel flow. If it gets faster, the fuel flow can be adjusted faster as far as the exhaust temperature is within a limit. This may lead the prevention of plant trip-out. We check the relation between IGV speed and the trip-out frequency when the plant is under full load operation and the 85% load operation.

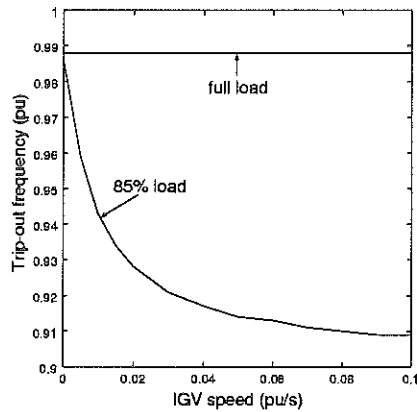


Fig. 14. IGV speed and trip-out frequency.

The result is shown in fig.14. In the case of 85% load operation, if the IGV speed gets faster, the trip-out frequency gets lower as we expected. However, in the case of full load operation, trip-out frequency has no relation with the IGV speed. This is because IGV is fully opened and the air flow cannot be increased.

### 4. CONSTANT FREQUENCY DROP TEST

#### A. Partial Load Operation

We investigate the influence of the constant frequency drop in this section and the following section. We drop the system frequency to 0.97 pu at  $T = 0$  (sec) and then fix it, while the combined cycle plant is under 85% load operation. Figure 15 shows the response of plant outputs.

Just after the system frequency drop, fuel signal is increased by the speed control. Consequently, the air flow and the fuel flow are increased at the same time. However, as the increasing speed of the fuel flow is much faster than that of air flow, exhaust temperature rises quickly. If the exhaust temperature exceeds the reference temperature, temperature control restricts the fuel flow. On the other hand, air flow is increased by the fuel signal until

the IGV gets fully opened. By this increase of air flow, exhaust temperature gets lower than the reference temperature. Therefore, restricted fuel flow can be increased again. Finally, fuel flow is increased until the exhaust temperature gets 1.01 pu.

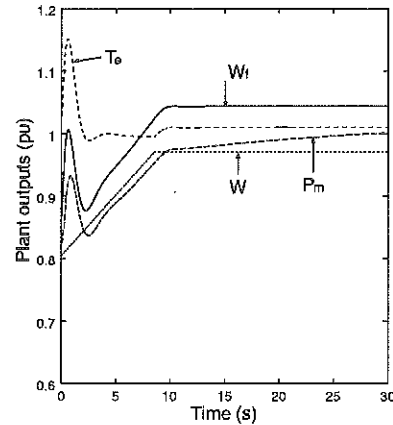


Fig. 15. Constant frequency drop test(85% load).

#### B. Full Load Operation

Then, we drop the system frequency to 0.97 pu at  $T = 0$  (sec) and then fix it, while the combined cycle plant is under full load operation. Figure 16 shows the response of plant outputs.

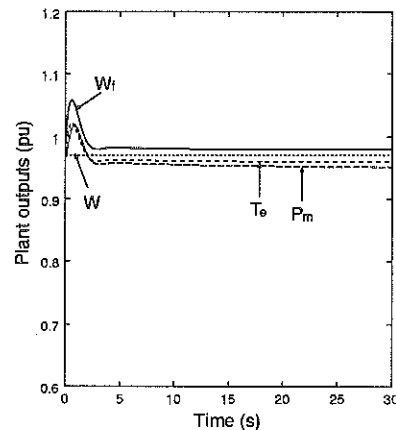


Fig. 16. Constant frequency drop test(full load).

Just after the system frequency drop, fuel signal is increased by the speed control. Consequently, only the fuel flow is increased in this case, and the exhaust temperature rises quickly. Therefore, temperature control decreases the fuel flow until the exhaust temperature gets lower than the reference temperature ( $T_r = 0.96$  pu). Eventually the power output gets smaller than the demanded load 1.0 pu.

Figure 17 shows the relation between fixed turbine speed (hence the system frequency) and the power output under the full load operation.

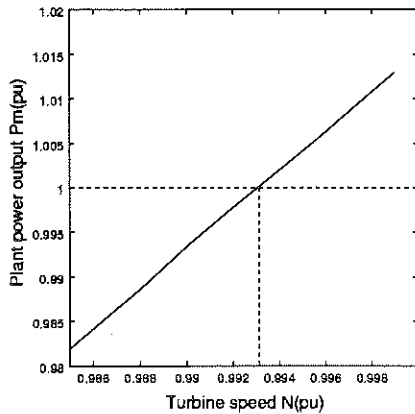


Fig. 17. Turbine speed and plant power output.

If the system frequency drops for a long period during the full load operation, the dropped frequency determines whether the plant output gets larger than the demanded load or not. If the dropped frequency is not so large, combined cycle plant can increase its output and recovers the system frequency by itself. However, if the dropped frequency is larger than about 0.007 pu, plant output gets smaller than the load and the system frequency cannot be recovered.

## 5. CONCLUSIONS

In this study, we made a single-shaft combined cycle dynamic model, and executed numerical simulations to see how the combined cycle plant behaves when the system frequency drops. The results are summarized as follows:

- (1) If the system frequency drops during the full load operation, combined cycle plant trips-out easily.
- (2) When the combined cycle plant is under the full load or high partial load operation, the trip-out frequency gets high and the plant becomes unstable.
- (3) During the full load operation, inlet guide vane is fully opened and the air flow would not increase. Therefore, an increase of the fuel flow raises the GT exhaust temperature. If the GT exhaust temperature is higher than a limit, temperature control acts so as to decrease the fuel flow. As a result, the turbine can not obtain enough power to accelerate itself, and its rotating speed keeps on dropping. This is the mechanism of the plant trip-out.
- (4) If the IGV speed gets faster during the partial load operation, the plant trip-out frequency gets lower.

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## APPENDIX

Parameters for the example combined cycle plant are given below.

Table A1. Gas turbine parameters.

| parameter | value                                                  |
|-----------|--------------------------------------------------------|
| $T_{i0}$  | compressor inlet temperature 30 ( $^{\circ}\text{C}$ ) |
| $T_{d0}$  | compressor outlet temperature 390                      |
| $T_{f0}$  | gas turbine inlet temperature 1085                     |
| $T_{e0}$  | gas turbine exhaust temperature 505                    |
| $P_r$     | compressor pressure ratio 11.5                         |
| $\gamma$  | ratio of specific heat 1.4                             |
| $\eta_c$  | compressor efficiency 0.85                             |
| $\eta_t$  | turbine efficiency 0.85                                |
| $K_2$     | coefficient of combustor temperature 695               |
| $K_0$     | coefficient of gas turbine power output 0.003030       |
| $K_1$     | coefficient of steam turbine power output 0.000428     |

Table A2. Combined cycle parameters.

| parameter   | value                                        |
|-------------|----------------------------------------------|
| $W$         | coefficient of governor 25                   |
| $X$         | coefficient of governor 0                    |
| $Y$         | coefficient of governor 0.05                 |
| $Z$         | coefficient of governor 1                    |
| $K_4$       | coefficient of radiation shield 0.8          |
| $K_5$       | coefficient of radiation shield 0.2          |
| $T_3$       | radiation shield time constant 15            |
| $T_4$       | thermocouple time constant 2.5               |
| $T_5$       | coefficient of temperature control 3.3       |
| $T_i$       | ratio of temperature control integration 250 |
| $T_{cmax}$  | temperature control signal upper limit 1.1   |
| $T_{cmin}$  | temperature control signal lower limit 0     |
| $LVG_{max}$ | LVG upper limit 1.5                          |
| $LVG_{min}$ | LVG lower limit -0.1                         |
| $K_3$       | ratio of fuel adjustment 0.77                |
| $K_6$       | fuel valve lower limit 0.23                  |
| $T_v$       | valve positioner time constant 0.05          |
| $K_f$       | fuel system feedback constant 0              |
| $T_f$       | fuel system time constant 0.40               |
| $W_{max}$   | IVG upper limit 1.0                          |
| $W_{min}$   | IVG lower limit 0.70                         |
| $T_m$       | waste heat recovery boiler time constant 5   |
| $T_b$       | waste heat recovery boiler time constant 20  |
| $T_{cd}$    | compressor volume time constant 0.2          |
| $T_r$       | turbine rotor time constant 18.5             |

## Discussions on Session IX: STABILITY ASSESSMENT & RESTORATION

### Part 1

**Chairman (H. Sugihara):** We have about 30 minutes of discussion time. Please give your name and affiliation. Of course our speakers can ask or give comments.

**J. P. Paul:** I'd like to ask Professor Pavella a question about what she just presented. I think, but even in an open market, it seem that transient stability is considered in planning, one day ahead or a few hours ahead, even if we're de-regulated system. Why in your paper you are applying it in real time?

**M. Pavella:** Concerning the use of the method for transient stability assessment, there are systems that are transient stability constrained and some are more voltage stability constrained. So for this system, it's important to have transient stability in where you know that you work in a preventive mode. For the Brazilian system that we have been working with or other systems, I would say that contingency filtering, which of course is very easy to realize. So instead of using a single computer, you can use three. If you use the single computer with the Brazilian system way of assessing the 850 contingencies and stabilization, etc. If you allow me, this is a preventive type. Maybe it could be assessed to be too expensive. So, the other possibility is to go for an emergency control. After having cleared from the contingency, predict whether the system is going to be unstable, if he has how much on station to, in this case not to shift but to shed. But this is of course the scheme of the system, it's just for very delicate place. But it's the other way of working, it costs more to shed generation in an emergency than to shift generation in a preventive mode but it happens much more seldom.

**C. Canizares:** This is for M. Pavella. Even though you didn't mention sensitivities, I guess one of the techniques you describe is precisely for market to try to resolve the problem, whatever that is, to whatever contingency. Could you elaborate a little bit on the sensitivity calculation and how you go about it?

**M. Pavella:** It is easy to use sensitivity approaches. We have been simulating many systems, for instance the 600 set. The critical clearing time versus the margin relationship is almost linear. There are nice properties that we haven't worked to prove theoretically. Therefore, going for ATC calculation via the sensitivity approach is the same way as for steady state ATC security. This is one subject we're working on right now.

**C. Vournas:** I have a question for Dr. Kakimoto. It's very interesting to see in your paper, the reason why combined cycle plant is not used usually for frequency

control. From your study, could you see a way of combined cycle plants in frequency regulation? If you can find a solution to this problem, it could be helpful.

**N. Kakimoto:** It is a difficult question to me. In Japan we have conventional type of generators. If the output decreases because of the temperature control of decreasing rotor speed, other generators must compensate. That is one problem, I think.

**R. Schlueter:** We have used trajectories that occur as bifurcation and a very sharp spike through the time trajectory. We've also shown that if the voltage input declines you get to a singular surface, and again you can't say without trajectory sensitivity. This has been used by others to work on bifurcation in the trajectory.

**T. B. Nguyen:** Yes, I agree with you that the trajectory sensitivity has been used by many people.

**N. Yorino:** I would like to ask Professor Pavella. You might said your method is for on line, and it can be used for preventive control and as well as corrective. In practice is it possible? If you can quickly start the action, so you can prevent some contingency in some cases.

**M. Pavella:** I can comment on emergency control. The preventive side is based on simulations. Now after we measure the power plants. We assume that this measurement is about 15 msec, then it works very quickly. So 15 msec after the contingency has been cleared, and we wait for 3 or more steps, about 100 msec after the fault clearance, we know whether the system is going to be unstable, and how much it's going to be unstable. There may be generations to be shed, then the action of the generation maybe triggered after 50 msec plus 50. All in all it would take about 400 in between 340 msec to act. This is the closest. After shedding you get new measurements, and if the shedding is not enough, then you can trigger new actions. But this is based on your measurements, and this emergency control means we'll have another, by the way, European project where we're going to try on the Italian system, because the Italian system has a problem in the southern part. They would like to know whether it's possible to go with this emergency type of control.

**N. Yorino:** Thank you very much. But I'd like to ask that how do you transfer the data.

**M. Pavella:** The data we need are from the generators, mechanical power, electric power, rotor angles. We

take sort of the center of angle of one machine, center of angle of the other machine, and then we take one machine infinite bus equivalents, so all these data come from simulations or they are reflected in the measurements. The measurements reflect the real system. For the simulation, they come from the main program. So generally we use the time domain program, which is normally used, for instance, the Hydro Quebec system we use 600, with the American system we use the ETMSP, with the French system or Belgian system or some other system we use Eurostag or ABB program, or the Italian program. That's for the preventive side. We collected all this data, and refresh this parameter at each time step domain. So it is a really accurate replica of the behavior of the multi-machine power system.

**I. Hiskens:** In the on-line version, are you sharing a particular mode of instability and determine what the mode, the generation mode, is as it goes along?

**M Pavella:** Are you talking about modeling?

**I. Hiskens:** About the mode of separation, which generators are separated in the critical group? Is that determined a priori?

**M. Pavella:** As I said, some candidates separation patterns are based on their angular deviations, and then it finds out which are the maximum gap between 4 or 5 or 3 candidates of separation patterns. For each one of the patterns, it must reach the unstable condition. As soon as one of them is in an unstable condition, it concludes that the system is going to separate, and therefore, you know the advanced machine. At another end you might have a critical machine.

**I. Hiskens:** Is it established a priori?

**M. Pavella:** Again I didn't get the part.

**I. Hiskens:** They are established off-line, they are determined beforehand. Is that correct?

**M. Pavella:** No. It is a time simulation, at each time step, that is this thing is very fast to grip the center of angle machine. It stops by itself in real time during the simulation.

**I. Hiskens:** But you mentioned that there are a number of candidates patterns for modes, and so check these candidates? Maybe we should talk later a little bit. I think you mentioned that there is a number of candidates groupings, that is monitoring.

**M Pavella:** The first of which is chosen? Is this what you say?

**I. Hiskens:** Yes, but there are a number of this has been monitored?

**M Pavella:** Yes. It's four or five candidates. In the simulation, at each time step of the time domain program, you check according to their angular deviations. Then you find where is the separation between two adjusted machines. Everything is set during the timed domain simulation in between 2 time main steps.

**I. Dobson:** This question of the relationship between the singular surfaces, because, first of all, the way from the equilibrium point at the point of the trajectory and any quantity. For example, the critical trajectory which is at the border line stability, clearly that trajectory goes to a-on the way must therefore---because an eigenvalue of Jacobian must pass through 0, so we know that trajectory must have passed through the principal singular surface. I wonder if you had thought more about this trajectory sensitivity and the Jacobian singularity, the dynamic itself more exactly?

**T. B. Nguyen:** The critical sensitivity, you said it no relationship with the Jacobian, is that correct for you question?

**I. Dobson:** The sensitivity is integrating the Jacobian. So at one point, it does not tell you how it is integrated. .

**T. B. Nguyen:** At one point, it is just that one considered just one point along the trajectory. But from a special point, like my presentation here, the point I chose is right up the crossing up the principal singular surface. The eigenvalue go from the left through the half plane, that's a significant difference.

**I. Hiskens:** One statement you can make is rather than a principal singular surface, if you look for the Jacobian on the half plane, on that region you can get a metric part, because we're dealing with a time varying system. In terms of surface, it doesn't really tell us a lot. Analytically it just seems to guess possibly some time scale is small relative of the space of the trajectory then you can make some kind of this statement. But we haven't explored that a whole lot - stability boundary. Then you clearly have an unstable Jacobian, and the trajectory close to that, then you see a peak happening and increase toward a large number. In between those two cases, there is not any analytical statement that one can make.

## GUIDELINES FOR ISO OPERATOR AID AND TRAINING FOR POWER SYSTEM RESTORATION IN OPEN ELECTRICITY MARKETS

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### Abstract

Plans to defend and restore electric energy systems have been historically developed all over the world to provide a rapid and secure recovery of a normal operating condition.

Migration from vertically integrated utilities to open access environment poses the question, particularly felt in Europe, to reassess the basis of such plans in order to hold equal, or even better, standard of system security.

In Italy, in particular, the restoration of a power system after a blackout has made use up to now of the black-start capability of selected hydro power stations (named 'early-restoration plants') through pre-established paths called 'restoration lines'. With the unbundling and liberalization of the electrical energy systems, some studies have been recently carried out for assessing the possible contribution to the restoration plan from thermal units. Some results relevant to geothermal plants, to steam power plants repowered with gas turbines and to combined heat and power generating plants are included in the paper.

The paper reports also on additional topics to consider while developing defense and restoration plans in deregulated regional/national systems. Such elements constitute the skeleton of an intelligent supporting, and training, aid for independent system operator (ISO) control center personnel.

### 1 Introduction

In Italy, and in most European countries, the liberalization of the electric power market is introducing multiple, new participants, split responsibilities and is causing the definition of quite precise rules to govern power and energy service.

Unfortunately, ancillary service provision strategies have instead been derived, with insufficient deal of criticism, from former structures, mainly related to national, vertically integrated network management.

Moreover, while contractual agreements with distribution utilities and final users were considerably tested, reduced experiences have been matured so far, in dealing with required

behaviors of generation companies, especially in emergency conditions. In other words, it is still under question if it becomes more efficient, and therefore profitable, to leave the ISO complete co-ordination of protection and control systems when avoiding network separations or recovering from black-outs.

Anyway, it is widely accepted that multiplicity of ownership increases risks of emergency, due to often-conflicting interests among committed parties.

To provide some elements on the amount of work that needs to be done, the paper starts from the examination of the Italian defense and restoration plan, with the aim of providing guidelines for improving its efficiency and for supporting control center operators in decision making, and training, during real, or simulated, emergency conditions.

In Italy the restoration of a power system after a blackout has made use up to now of the black-start capability of selected hydro power stations (named 'early-restoration plants') through pre-established paths called 'restoration lines'. Section 3 summarizes the results of some studies that have been recently carried out for assessing the possible contribution to the restoration plan from thermal units, and, in particular, from geothermoelectric plants, from steam power plants repowered with gas turbines and from combined heat and power generating plants.

The results constitute the basis for an under development expert/simulation tool to be considered for possible application in the ISO national and regional districts. This expert/simulation tool is described in section 4.

### 2 Italian Defense and Restoration Plans

Recent redistribution of roles within the European electric power system environment caused the institution of national or regional ISOs, who are responsible for transmission grid operation, and act to hold predefined levels of security and quality of service.

Defense plans aim at maintaining a normal working point in a system evolving towards emergency, as well as to recover to a



normal condition a still emergency operating grid.

Normal and emergency conditions are defined according to a broadly accepted state diagram (and possible extensions) [1, 2] and commonly considered security criteria ( $n-1$ , and so on), where control actions provide recovering transitions.

European countries usually distinguish, according to the different type of experienced emergency, between automatic and manual interventions, and also develop different strategies according to interconnected and isolated conditions.

Defense plans try to anticipate dangerous trends towards blackout conditions, and express themselves to overrule conventional protection interventions. Roughly speaking, they behave like secondary control loops with regard to local protection systems, since they point to an area secure management.

If every protective measure proves unsuccessful, part, of reduced or significant extension, of the transmission grid reaches a blackout condition.

Such an in extremis working point is recognized and assessed according to criteria considering abrupt voltage and frequency decays and power abnormal oscillations, but some of them would be probably avoided by profiting of advanced monitoring devices [3], able to assure a network state estimation also during emergencies, and by driving specific controls.

When blackout is reached, restoration plans become effective, committing

- black-start resources to reenergize radial transmission paths for subsequent ballast load insertion;
- parallel operation of large thermal units;
- generation ramping;
- interconnection between restored paths and
- final complete load recovery.

### *2.1 Remarks on present form of defense and restoration plans*

As earlier mentioned, plans to defend and recover electric transmission system in deep emergency conditions were elaborated with reference to vertically integrated national utilities.

Due to this point, manual and automatic corrective measures were considered to be performed under supervision of regional/national control centers, so that open access environment forces towards specific contractual agreements to propose the same procedures.

Apart from this crucial item, defense and restoration plans seldom show significant degree of reciprocal co-ordination: while the former act with local or diffuse generation tripping and/or load shedding, the latter looks for black-start sources and restoration paths to re-energize.

Partial or complete blackout conditions are preceded by network separation phenomena (driven by cascading outages, protection incorrect tripping and unavailable components under maintenance), which determine isolated subsystems operating at different frequencies.

Load shedding relays, as well as generation tripping ones, in single or progressive interventions should theoretically guide the grid to new equilibria, with reduced energy exchanges, but with the chance to operate a load recovery and a network re-synchronization as well.

Transient behaviors of an electric system under separation may lead to incorrect generation tripping, or creation of surviving subsystems with internal shortage of generation resources.

Under frequency operation in areas with prevailing thermal generation can cause blackout in the following cases:

- The internal generation/load mismatch is so relevant that load-shedding relays prove unsuccessful to restore acceptable frequencies, taking into account of users with preferential contracts or significant social impact.
- Thermal units are not provided with load rejection facilities and no special defenses are implemented to tailor appropriate load areas around them.
- Thermal units are equipped with load rejection facilities, but these are activated by a load drop anticipating relay, rated at the minimum operating real power level (30-40% of the rated power in case of supercritical UP boiler, with low pressure flash tank). In such a particular case, when insufficient hydroelectric and gas turbines groups are present in the considered area, even if a new equilibrium point could be reachable, the required generation profile is unsustainable for large thermal units, so that the subsystem collapses.

The Italian geographical configuration, in addition to its frequent dependence in energy supply from neighboring countries, suggests high probability of black out after separations. If this process results in isolated areas with either reduced local generation, or prevailing part of UP thermal units, defense plans become useless to rescue the under-frequency subsystem.

At the time being, Italian defense plans accounts for load shedding protective system, only used within major urban areas. Moreover, the only link with restoration plan is the constraint of not involving ballast loads for restoration paths in load shedding relays area of influence.

Under these limits, it is stressed that the present restoration plan is elaborated for complete loss of power supply. In other words, restoration paths, including sequences of predefined maneuvers, develop from assigned black start units regardless of how the system came to such in extremis condition. There is only a limited chance for the regional control system operator to stop the restoration path building whenever a surviving area

is identified to be significant for large thermal unit restoration.

Unfortunately, this profitable ‘change of mind’ requires supervision activity by operation centers, and complete availability of communication channels, of doubtful efficiency in black out conditions. Section 4 will provide some guidelines for operator aid and training for power system restoration in open access environment.

An other issue is that, as already mentioned, the Italian restoration plan requires that the black-start maneuver is started from by selected hydro power stations. The turbines of these stations are equipped with a special speed governor and are devoted to start-up thermal units through pre-established paths called ‘restoration lines’. Because of the great distance between those early-restoration hydro plants and some important thermoelectric groups station belonging to the southern (and more stretched) part of the Italian HV transmission network, in the past some studies have already been carried out for assessing the possible contribution of conventional thermal units to the restoration plan. The unbundling and liberalization of the electrical energy systems has justified further investigations. The main results of some recent studies are summarized in the following section.

### 3 Black startup capability of thermoelectric power plants

The deregulating process now being developed in most of industrialized country in the energy sector has received a strong impulse by the new technologies now available for power generation. In fact the CCGT (Combined Cycle Gas Turbine) technology allows the operators (often non-electric utilities) to rapidly build and put in service high efficiency and low investment power plants. In several cases obsolete steam plants have been repowered by adding a first stage based on gas turbines.

Therefore the power plant scenario is rapidly changing and these new resources must be regarded as powerful tools for improving the power system reliability.

Moreover, the developments in the power electronics technology can give a strong impulse to exploit power plants usually not adopted for restoration purposes.

A review of the studies recently carried out to assess these possibilities is reported here, with main reference to:

- geothermal power plants;
- steam power groups repowered with gas turbines;
- autoproductors and combined heat and power generating systems

#### 3.1 Geothermal power plants

In some regions among the world, geothermal fluids are available relatively close to the ground surface. This allows building steam power plants exploiting this natural and cheap source.

Geothermal power plants are characterized by a simple steam cycle, which allows operating units of outstanding reliability and yearly availability higher than 8000 hours. Usually these plants are designed and classified to supply the base load in the grid and are not structured to provide network services.

Normal start-up of such units requires the energisation of the auxiliaries, usually by the primary distribution network. In the case of emergency conditions, the power plant performs a load rejection maneuver and remains in operation islanded on its own auxiliaries. However this maneuver sometimes fails, due to auxiliaries’ protection intervention caused by inadequate design.

The possibility of improving the unit performance during emergencies and during restoration procedures by means of the installation of a SWVC [4] (Static Watt Var Compensator) has been tested. The installed device should allow feeding the auxiliaries on a separate and stable source during major system disturbances and start the geothermal power plant in blackout conditions.

SWVC power and battery storage energy ratings are basically designed to provide the power needed to start the condenser extraction pump during the black-start maneuver, and to feed the electrical auxiliaries until the main generator can feed them on a separate island.

In Italy, there are circa 30 geothermal power plants, with an installed capacity of more than 800 MW. One of them (the Valle Secolo power plant) consists of 2 units of 60 MW each. A study [5] has been recently carried out to assess its capability to energize, after a blackout, the electrical auxiliaries of one of the four 320 MW groups of the steam power station located near Piombino.

Referring to the scheme of Fig. 1, showing the geothermal and the steam plant, the following steps in the restoration procedure can be identified:

- keep the auxiliaries fed on a separate network in case of a major disturbance to lead to a “soft load rejection”, or, in case of failure;
- start the auxiliary services of the geothermal plant by means of the SWVC, and start the geothermal plant turbine, excite the generator, and transfer the auxiliaries’ supply to the generator;
- energize the 132 kV connection to the auxiliaries of the steam plant;
- start the auxiliaries and the steam turbine;
- synchronize the steam power plant, after the energisation of 132/400 kV transformer ATR, and ramp the steam plant to its minimum power limit.

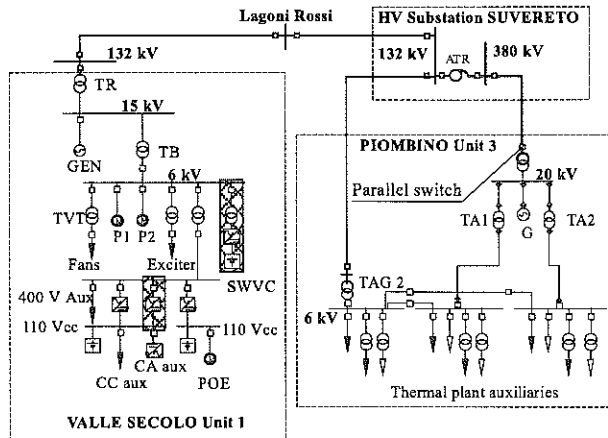


Fig. 1. Scheme of the thermal and geothermal plant

Fig. 2 and Fig. 3 show the results of two simulations: the first refers to the case of a generation-load power mismatch causing a descending frequency rate of 1 Hz/s and the second to the case of a progressive, long term voltage decay at the HV bus of the geothermal plant. At 1.2 s in the first case and at 75 s in the second simulation, the electrical auxiliaries' system of the geothermal plant is islanded and fed by the SWVC.

The SWVC action aims to separate and feed the auxiliaries thus avoiding that the supply disturbance may cause the trip of the group. The generator may therefore remain in operation, co-operating with the grid to face the disturbance, until the intervention of a protection. In the case of Fig. 2, such a protection is an under-frequency relay, and, in the case of Fig. 3, it is a protection for low voltage or for excessive temperature of the condensing water (due to temporarily out of service of refrigerating fans). Then, the unit is disconnected from the network, through a load rejection maneuver.

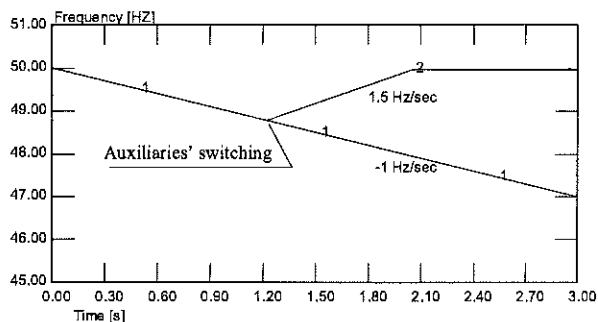


Figure 2. System (1) and auxiliaries frequency (2) during a system frequency collapse

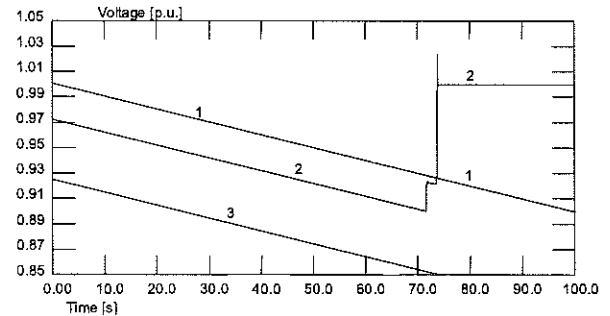


Figure 3. Generator (1), auxiliaries (2) and grid (3) voltages during a system voltage collapse

If the load rejection maneuver fails and the plant trips, the SWVC can startup the electrical auxiliaries of the geothermal power plant, and, in particular, the condenser extraction pump at variable frequency.

The following phases of the restoration maneuver consist in energizing the lines and transformers that connect the geothermal power plant to the Piombino steam power plant and in starting up its electrical auxiliaries. The critical points of the maneuver can be identified in the high value of the inrush currents of the 75 MVA unit transformer (TR) and of the 250 MVA substation autotransformer (ATR) and in the high rating of some induction motors of the steam group auxiliaries system.

Fig. 4 shows the behavior of the current at the generator of the geothermal power plant during the energisation of the lines and transformers TR and ATR. Fig. 5 shows the voltage behavior at the busses of the two power plants, during the startup of three of the motors of the auxiliaries' system of the steam power plant. The current and voltage transients result to be compatible with the settings of the power plant and network protections.

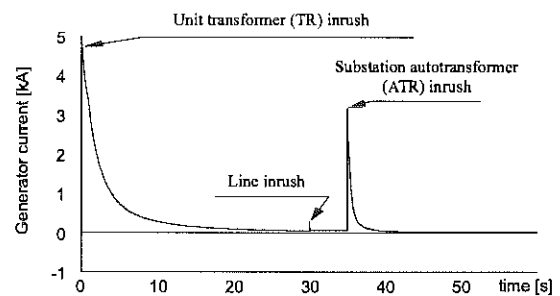


Fig. 4. Energisation of the path to the thermal plant: current supplied by the Valle Secolo generator.

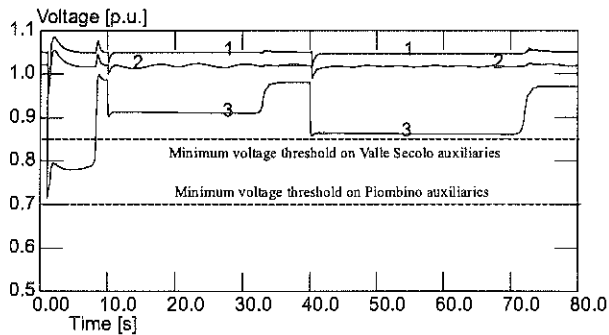


Fig. 5. Startup of three induction motors of the auxiliaries of Piombino steam power plant, namely a feeding water pump of 6.5 MW, and two fans of 1.9 MW and 3.1 MW. Voltage profiles: 1) at Valle Secolo generator, 2) at Valle Secolo auxiliaries' bus, 3) at Piombino auxiliaries' bus.

After the synchronization of the generator of the steam power plant, the two groups will co-operate to allow the steam power plant to reach its technical minimum load of 110 MW. In this phase at every load pick up, the steam power plant participates with the geothermal plant to the frequency regulation and the load is initially shared between the two plants. However, in the following seconds, as shown in Fig. 6, the governor of the geothermal power plant increases the output of its generator, satisfying in this way the total ballast load demand. The steam group can therefore perform its predefined loading ramp at 2 MW/min.

In this conditions, a 20 MW load pick-up gives rise to a transient that has been verified to be compatible with the requirements of the steam power group [5].

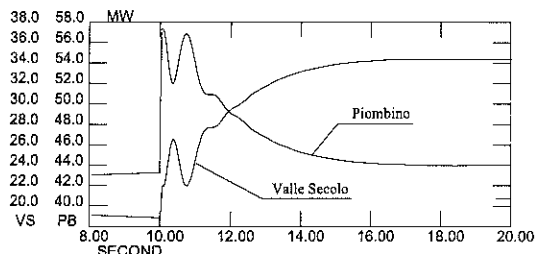


Fig. 6. Power sharing between the plants during the energisation of a load.

### 3.2 Thermoelectric steam power plants repowered with a gas turbine

As already mentioned, some studies have been carried out in the past [6,7] for assessing the possible contribution to the restoration plan from the conventional steam thermoelectric units.

First of all, for all the ENEL units with once-through boilers, a specific load rejection procedure has been developed, tested and used in several occasions. The procedure consists of tripping all fuel to the boiler without tripping the turbine, switching the boiler to the startup and bypass circuit, and then

re-firing it after a certain period of time (up to 30 min) during which the house load is maintained on the energy and mass stored in the boiler [8]<sup>1</sup>. Only a limited number of attempts are allowed to perform new ignition, which in case of failure force the unit to a cold restart because of inadmissible thermodynamic conditions.

If the complete load rejection process is successfully accomplished, the thermal unit can remain in operation feeding a restored island of the network, but its chance to autonomously collect load still remains questionable, since it strongly depends on prime mover specific characteristics. The results of the tests reported in [6,7] show that even when these units have successfully completed the load rejection maneuver and have been successfully islanded on their own auxiliaries, they should pick-up load after their synchronization with other units, in order to reduce the probability of tripping on under frequency.

This is supported by a study recently carried out with the aid of an engineering simulator of a 320 MW steam group equipped by a once-through universal pressure (UP) boiler [9]. During the black-start manoeuvre the most important transient phenomena regard the boiler dynamics. A simplified steam section model is adopted by taking into account the mass and momentum conservation equations as well as pressure regulation dynamics. Temperature regulation effects, instead, have been neglected, as they involve time constants much greater than those relevant to pressure dynamics, as shown by the results obtained by using the more detailed simulator. The model of the electrical system of the power plant is conceived to reproduce the slow electromechanical transient phenomena. Faster dynamic phenomena such as electric and magnetic transients due to overvoltages have been disregarded. The presence of the voltage regulators, including the generators capability curves, is also considered. The results of the simulations show that the steam section, when feeding its auxiliary systems, can overcome the frequency transient due to ballast loads connection, provided that the load power is lower than 18 MW. The main reason for the maneuver failure is the fall of the throttle pressure due to the speed regulation that opens the admission valve. Fig. 7 shows the results of the simulation of the failing of a 30 MW load pickup. As shown in Fig. 7, the critical condition for the steam turbine occurs when the admission valve is fully open and the steam pressure is coming down so the mechanical power decreases. Being the mechanical torque balance negative, the frequency drops rapidly causing turbine trip.

<sup>1</sup> For the case of oil fired drum boilers, it is also possible to operate by keeping burners in service. In case of failure of such a maneuver, the process can continue, after the boiler trip, relying on stored energy and mass. For drum boilers burning coal or natural gas, it is preferable to trip the fuel from the beginning [8].

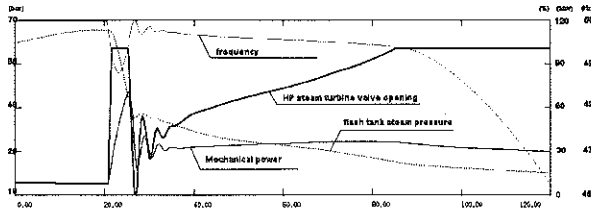


Fig. 7. Simulation of the pick-up of a load of 30 MW by a 320 MW thermoelectric unit (adapted from [9]).

During the last ten years, some ENEL thermal power stations, most of which consist of 320 MW steam turbine units equipped with once-through UP boilers, have been repowered in combined-cycle. The repowering technique adopted by ENEL consists in topping the existing steam sections with a 120 MW gas turbine and recovering heat from the gas turbine exhaust flow by means of an exchanger, which substitutes part of the high-pressure feed-water heaters [11].

An electrodiesel generator is able to feed the auxiliaries of the gas turbines in order to perform the start-up maneuver, and the gas turbine can, in turn, start the auxiliaries of the steam group. This is made easier, in the combined cycle power plants of the Italian Utility, by the presence of the bypass valve that diverts the gas turbine exhaust flow from the exchanger, making the two sections (gas and steam) completely independent in this phase. The presence of a gas turbine section justifies, therefore, further investigations on the black startup capabilities of these repowered stations. In the simulator, the gas section model considers essentially the speed and load regulation, fuel feeding combustor and air compression dynamics. The speed control system also includes a local frequency integrator (LFI) correcting the gas turbine load demand in order to reduce the frequency error to 0.1 Hz. This FLI intervenes when the frequency error exceeds 0.3 Hz or when the turbine power output changes too rapidly.

As earlier mentioned, one of the most critical problems during the restoration of a power system is the frequency control. It is necessary to avoid that load energisation transients cause significant frequency degradation such to involve generators' protections intervention. In case the gas turbine and steam thermal unit perform contemporarily the restoration maneuver, the two relevant frequency regulators must be suitably coordinated. As a matter of fact, the gas turbine is able to control the frequency error without significant delays, while the behavior of the steam unit depends on the thermal inertia of the boiler, very high at low load. This can impair the black-startup maneuver, and, therefore, as illustrated in [10], a load scheduler has been designed and implemented in an engineering simulator of an ENEL repowered thermoelectric plant. The basic function of the load scheduler is to maintain the gas turbine load as low as possible, in order to make it sustaining the whole frequency transient caused by the energisation of ballast loads. Only after the end of the frequency transients and if the boiler pressure is high enough,

the load scheduler increases progressively the load request to the SPP section, contemporarily unloading the GT. Another important role of the load scheduler is to provide the appropriate moment for connecting additional loads, taking into account both the gas turbine power output level and the steam unit conditions.

The behavior of this load scheduler is illustrated by Fig. 8, in which the simulation of the pick-up of several loads is shown. During every load pick-up, the steam section participates with the gas turbine to the frequency regulation only during the first seconds. In the subsequent minutes the frequency local integrator controller increases the fuel request of the gas turbine, satisfying in this way the total load demand. For this reason, the steam turbine does not increase its power, saving steam production in the boiler. When the pressure attains the 80% of its nominal value and the frequency error is less than 0.1 Hz, the load scheduler progressively discharges the gas turbine and increases the load request of the steam turbine. This maneuver is performed at 2 MW/min slope. This simulation shows that the steam section reaches in 50 min its minimum-operating load of 110 MW.

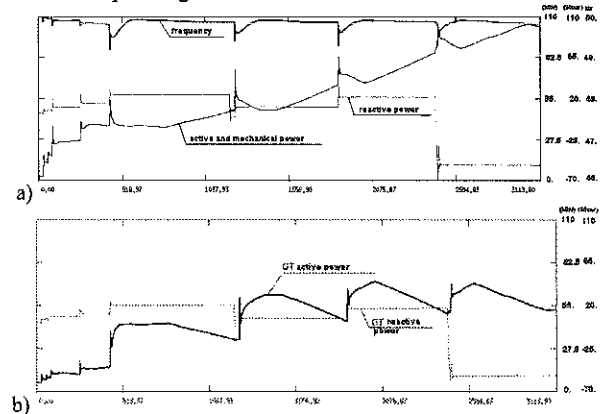


Fig. 8. Simulation of the pick-up of several loads by a 320 MW thermoelectric unit repowered with a 120 MW gas turbine: a) steam section outputs, b) gas turbine outputs. (adapted from [9]).

### 3.3 Industrial power plants and combined heat and power generating systems

In vertical integrated utilities, black-start capabilities of independent power producers (IPPs) were not taken into account, as well as those of embedded generation.

In the present open access environment, the use of combined heat and power plants of IPPs, usually located within or in proximity of industrial areas, as black start sources seems very promising.

The related positive aspects are equally significant for both the transmission manager and the power producer. The former benefits of the possibility of rapidly supplying adjacent, otherwise lost, consumers and the electrical auxiliaries of

thermal power plants, not provided with black start resources. The latter can continue producing the steam required by industrial thermal loads, as well as it can achieve a profit by providing the black startup ancillary service.

It must be pointed out that blackouts represent a relevant damage to most of the IPP, worsened by the associated industrial process, to be evaluated according to outage duration and prime mover nature. In general terms we can distinguish between generators whose production is used for internal consumption (autoproducers) and generators whose production is mainly directed towards the electricity market. For the former producers, damage consists in a reduced quality of service, since the industrial power system is islanded from the transmission grid, thus lacking of spinning reserve and regulation facilities. In addition, these kinds of producers are penalized for not selling overproduction to the transmission power system or to other customers. The latter producers have the loss of missing the chance of selling energy and coercion to additional charges in abrupt shutdown and subsequent restart.

In the case of combined heat and power generating system losses due to blackouts may be significant greater because, if the electric service fails to be recovered in short times, the heat production, feeding the industrial process, usually trips, with consequent losses of industrial production.

Investments in black startup resources can be therefore economically justified. Technical details are however highly dependent from the actual layout of the industrial power plant.

#### 4 Guidelines for operator aid and training for power system restoration in open access environment

After the detection of a blackout condition, presumably partial in probabilistic terms, in the relevant area, one can identify busses with null voltage, as well as surviving busbars where some thermal units are performing the load rejection maneuver.

The operator has then the option to reenergize the disconnected regions by black start generation, or can prefer to wait for load rejection to succeed, or at least to profit of available surviving subnetworks, created according to defense plan strategies.

The developed investigation is aimed at determining, before starting the effective restoration, the convenience of each choice with respect to the others, in order to minimize disconnection times as well as to maximize recovered loads. With regard to this point, it must be noted that time and load evolve in a “discrete” way, the former being linked to the maneuver execution time, the latter being available in form of (hopefully several) fraction parts.

To successfully accomplish the restoration procedures, one must account for the multiple phenomena involved in service recovery, extensively presented and quantified in the literature on the subject [12, 13].

Therefore, each potential restoration source, including both early restoration plants and border busses of surviving networks, is qualified assigning a specific merit index, according to the following attributes.

- Size: it constitutes a significant attribute, in that it enables load acquisition and real power transfer after the synchronization of major thermal units with reduced black-start capacity. Units of large size are of course to be preferred; concerning the restoration capabilities at border busses of surviving networks, they are to be evaluated as shown in the Appendix.
- Autonomous start up: it expresses the chance of the power unit to perform start up procedures without electric energy supply from external sources, typical condition during black outs. Several types of electric power plant may, in principle, be started in autonomous way if equipped with adequate black-start devices [4, 9]; nevertheless, required power levels and energy amounts strongly reduce practical application of relevant technologies in many cases. Merit should be given to units requiring limited time in performing the whole startup process. In this respect the busses at the borders of surviving networks are immediately available.
- No load performance: the unit, after being successfully black started up or after completion of the load rejection procedure, should operate stable on its auxiliaries or on an load island, until the ISO provides the possibility to synchronize such a unit with a recovered area equipped with sufficient base load. Most units safely operate for significant time in such conditions.
- Energisation capacity: the restoration source is called to reenergize disconnected connections such as step-up and step-down transformers, as well as overhead lines or cables. Phenomena like harmonic resonance, ferroresonance or transformer in-rush currents must be accounted for, also taking into account component non linearities and evolving topology. Capacitive loads are to be compared with reactive power capabilities of committed early restoration units. Both units and surviving network terminals show better performances if characterized by high values of short circuit power.
- Cold load pick up response: the restoration source must be stable while picking up load blocks of expected size. However, according to the load nature [7], real and reactive power overshoots are frequent, so that the actual dynamic behavior of the system is often worse than the expected one. This is strongly related to regulation device characteristics and unit inertia time constant, finally affecting the choice in load reconnection priorities. Each unit should be characterized by the load amount that can be energized with sufficient quality of service.
- Regulation capacity: separated operation, including stable load energisation, often requires specific regulation devices. Italian defense and restoration plans, with regard to generation sources, are based on specific devices available at hydro and fossil units. Indicators like speed governor

permanent droop and automatic voltage regulator (AVR) gain may be used to rank the units according to performance in restoring the network. For the case of surviving areas, some procedures to infer equivalent indicators are described in the Appendix.

- Generation ramping rates: each early restoration source is characterized by some constraints that limit prompt load energisation. These constraints are typically related to the involved prime mover.
- Price of the black-start services: each black start unit contributes to the restoration plan if it has a contract with the ISO that settles the price of the black-start services. In the case of a blackout, units with lower prices will be preferred to the others in order to restore the network.

The merit index used to sort the available restoration resources is the balanced summation of the values given to the above-mentioned attributes, each adequately normalized. Figure 9 presents an example of merit index generation by an expert system prototype in the case of a group of Trino combined cycle power plant, located in the north-western part of the Italian transmission grid.

| Trino gruppo 4                        |  | Values |
|---------------------------------------|--|--------|
| Size [ MVA ]                          |  | 1400   |
| Rn autonomous start up time [ s ]     |  | 2400.0 |
| Rn no load performance up time [ s ]  |  | 1.0e5  |
| Maximum peak load [ MW ] [ MVAR ]     |  | 50.0   |
| Maximum load [ MW ] [ MVAR ]          |  | 30.0   |
| Maximum evolution time [ s ]          |  | 40.0   |
| Droop [ p.u. / p.u.]                  |  | 0.001  |
| Black start bid [ £ / KVAh]           |  | 5000.0 |
| Ramping rates [ MW / min]             |  | 10.0   |
| Maximum reactive power [ - ] [ MVAR ] |  | 85.0   |
| Scs [ MVA ]                           |  | 378.0  |
| Regulation traditional                |  | YES    |
| Regulation special                    |  | YES    |
| Rn final score                        |  | 6.47   |



Fig. 9. Merit index generation for an Italian unit.

Procedures are generated to classify all the units and surviving zones terminals connected with EHV network, generating the merit indices and detecting the most appropriate restoration sources.

The average merit index acts as a threshold, splitting the sources list into two parts, the former including units that are candidate to recover the network, the latter presenting remaining generators to be considered as preferential targets in power system restoration.

Attention must be also given to subtransmission islands: they include ballast load, necessary to avoid excessive overvoltages while energizing EHV lines, as well as for providing base power for parallel operation of large UP thermal units. In addition to this, they could contain minor units, as well embedded generation, useful to improve size and performance of the grid island under construction.

A parallel classification of target busses giving access to subtransmission network should be performed, according to the following items:

- Size: it refers to all the reachable loads within the island, considering the chance of reenergizing users from different access busses. Procedures should be introduced to manage an initial split of the loads between the terminals and a following redistribution of them after each commitment.
- Included generation: small units may be involved in restoration process while recovering ballast loads. Merit should be given to subtransmission islands presenting extended embedded resources.
- Load fractions and nature: extreme attention must be given to the chance of reconnecting load in a progressive way, so that each load should be characterized in the same way as the attribute of cold load pick-up was defined for generating units. Significant additional information will regard load type, in order to distinguish between static loads, asynchronous motors, thermostatically controlled or driving time-varying mechanical loads [7].
- Load distribution: within a subtransmission island, preference should be given to loads close to access node, to reduce overall restoration time. Indices like load momentum with respect to the access node could be adopted to drive restoration maneuvers.
- Load priority: it forces the restoration process to be directed towards users showing high social impact, being these ones the same to be last disconnected after the failure of the defense plan.
- Ballast load bid: the provision of restoration ancillary services is quoted according to specific clauses in contractual agreements between ISO and distribution companies.

As a result of the complete node classification, the operator will be shown, or at least made aware of the expert system decisions about, sorted lists of sources and target busses.

The coupling procedure to start parallel restoration processes requires the following steps:

- a decisional criterion to join together sources and target busses, being usually the minimum electrical length or the minimum number of breaker operations.
- A contemporary check for mutual compatibility between the attributes of sources and target busses (for example, sufficient size of sources with regard to the load of the subtransmission island or to the base load of thermal units).
- The consideration for additional constraints, such as, for example, the suggestion of reducing the number of involved

transformers.

After developing the coupling procedure, which of course could leave some sources or targets uncommitted, the expert decision-support system does not provide restoration path in the conventional way.

First of all, out of service components, as well as operation failures, are accounted for, and the coupling procedure is restarted at any unforeseen occurrence.

Moreover, whenever a black start-up unit and the relevant step-up transformer successfully reenergize an EHV line, this recovered subsystem becomes a surviving network, with modified intrinsic characteristics with regard to the attributes that affect the merit index of sources.

According to this fact, each single operation should restart the classification procedure, therefore assuring complete system flexibility, but decelerating the decisional process. To this regard, an acceptable compromise would probably be the resorting of restoration sources only whenever a subtransmission island is accessed, or a new generating unit is synchronized to the recovered subsystem.

To test the proposed strategy, an expert prototype is being realized according to presented procedures; the following paragraph will briefly describe its architecture.

## 5 Outlines of an Associated Expert System Prototype

In a previous analysis [14], concerning an expert system prototype for power system restoration in a vertically integrated utility, complete detail of the construction of a restoration path was presented, integrating a knowledge development environment with an internal simulator. In fact, such a prototype is set-up by an expert system and a real time power system dynamic simulator. The restoration process is driven by the data coming from the simulator that describes the dynamic behavior of the reintegrating system and substitutes the SCADA system.

Modifications towards the present electric market structure, as well as the need for including dynamic phenomena evolving through very different time frames, suggest the use of more powerful codes for dynamic analysis along several terms.

The use of external simulators causes the expert system to be more efficient in processing multiple, parallel developing, scenarios. Even if reasonable, such a choice must account for the usual difficulty of treating with a continuously increasing network.

It has been therefore proposed an intermediate control motor, which manages variations of network topologies, providing a new network to the external simulator, while holding the state variables coming from the previous working scenario.

In other words, while the inference engine generates decisional files, codified in sequences of breaker operations, the control motor for the external simulator starts progressive simulations, with snapshots of significant variables fed back to knowledge development environment.

A limited subset of network variables, available at a predefined scanning rate, constitutes the basis for the expert system, or the operator if an interactive mode is adopted, to verify acceptable values for constrained quantities (frequency and voltage, for example) and empirically determined stability conditions.

The result of such check is the activation of subsequent maneuvers, usually performed after frequency and voltage recovery within safety ranges.

The control motor is in the end designed to accept strategy modifications driven by any new restoration source sorting procedure, considering new operation files coming from the inference engine.

## 6 Conclusions

The paper regards possible reassessment of power system restoration strategies in a competitive electricity market.

The unbundling and liberalization of the electrical energy systems has justified further investigations on the black-start capabilities of the various types of power plants. Some studies have been recently carried out in Italy for assessing the possible contribution to the restoration plan from thermal units that previously were not considered as black-start sources. The paper summarizes the obtained results relevant to geothermal plants, to steam power plants repowered with gas turbines and to industrial combined heat and power generating plants.

ISO control center operators are asked to decide for best ways to recover from more or less extended blackout conditions, and cannot account on safe management of generation and consumption in extreme emergency condition.

Specific guidelines to dynamically create, and/or modify if more convenient, restoring areas have been here proposed and included in an expert system prototype for both operator assistance in decision making and training purposes.

## 7 References

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- ## Appendix

Definition of equivalent attributes for surviving network terminals:

- Extension: Graphically determined by direct intervention on the test network of the expert system prototype (see Figure 10). In a real application, identified through blackout assessment criteria.
- Size: as a first assumption, assumed equal to the MVA thermal rating of the connections departing from the considered border busses.
- Short circuit capacity: deduced by selected diagonal elements of the surviving network impedance matrix, obtained using LU factorization techniques. Each surviving network extension changes border nodes: admittance network based techniques for networks with increasing nodes may be adopted [14], still ending with LU factorization for new required driving point impedance.
- Inertia time constant and permanent droop: in approximate form, both deduced as weighted average through rated powers of included units, and assumed equal for each surviving grid terminal.

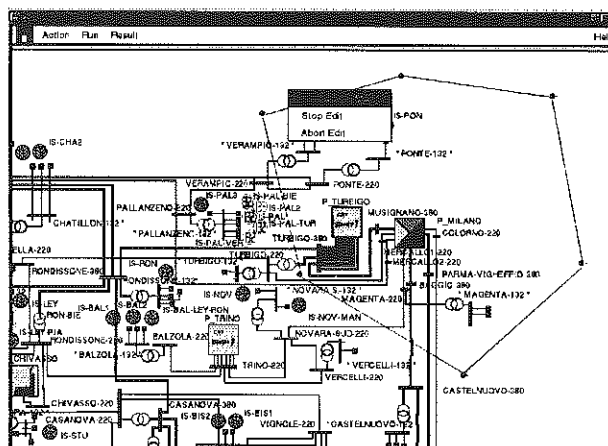


Fig. 10. Graphical set of a surviving grid while testing restoration strategies in an Italian sample transmission network.

# A New Multi-Agent Technique for Power System Restoration

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This paper proposes a multi-agent approach to power system restoration. The proposed system consists of several *Bus Agents (BAGs)* and a single *Facilitator Agent (FAG)*. A *BAG* is developed to decide a sub-optimal target configuration after faults occur by interacting with other *BAGs*, while a *FAG* is developed to act as a manager for the decision process. The interaction of several simple agents leads to a dynamic system allowing efficient approximation of a solution. It is shown from simulation results that this method is able to obtain sub-optimal target configurations which are the same as ones obtained by a mathematical programming approach.

**Keywords:** restoration, multi-agent system, agent-oriented programming, Java.

## 1. Introduction

In recent years, the electric utility industry world wide has been facing pressure to be deregulated or restructured in order to increase its efficiency, to reduce operational costs or to give consumers more alternatives. With respect to this, a great deal more research is needed to achieve better intelligent knowledge processes. The present centralized system for power system control, operation, and planning must be remodeled to cope with these situations. With the promotion of deregulation of electric power systems, a definition of an objective function regarding optimization problems, such as power system restoration, is becoming critical. However, conventional approaches enable us to solve optimization problems in only a single utility environment.

When electric power supply interruption is caused by a fault, it is imperative to restore the power system promptly to an optimal target configuration after the fault. The problem of obtaining a target system is referred to as a power system restoration. To obtain the target configuration, various approaches have been proposed. The method proposed, so far, to solve restoration problems can be roughly classified into four types: heuristics [1-5,13], knowledge based [4,6-11], mathematical programming [11], and soft computing

[12]. However, in an era of deregulation of energy policies, it is difficult to obtain an optimal target configuration by conventional approaches, since the coordination of all parties including independent power producers (IPPs) is required.

Currently, agents are the focus of intense attention in many sub-fields of computer science and artificial intelligence. Agents are being used in an increasingly wide variety of applications. Many important computing applications such as planning, process control, communication networks and concurrent systems will benefit from using a multi-agent system approach [14-17]. A multi-agent system is a computational system in which several agents cooperate to achieve some task. Multi-agent models are oriented towards interactions, collaborative phenomena, and autonomy.

This paper proposes a multi-agent approach to power system restoration. The proposed method consists of several *Bus Agents (BAGs)* and a single *Facilitator Agent (FAG)*. A *BAG* is developed to decide a sub-optimal target configuration after faults occur by interacting with other *BAGs*, while a *FAG* is developed to act as a manager for the decision process.

The proposed multi-agent system has the following characteristics:

- (1) In order to realize efficient processing, the types of agents are restricted and the number of communications between agents is also limited. In detail, only two types of agents, *BAG* and *FAG*, are created in the proposed multi-agent system, and a *BAG* communicates with only its neighboring *BAGs*.
- (2) The *FAG* is developed by using the "singleton design pattern" [18], which insures that only a single instance of the *FAG* exists at the same time.
- (3) The *BAG* has simple negotiation strategies:
  - If there are many branches for energizing the bus, the *BAG* selects a branch with the largest amount of restorative-available power.
  - If the amount of restorative-available power is insufficient, the *BAG* tries to restore the bus by forming a coalition of the neighboring *BAGs*.

- If a load must be shed because of insufficient restorative-available power, the *BAG* cuts off the smallest load that is connected to its own bus.
- (4) An object like KQML (Knowledge Query and Manipulation Language [19]) is used as a communication message object between *Agents*.

In order to verify the performance of the proposed method, many simulations are carried out using a model system that consists of 8 substations and 14 buses. From the results, it is proven that the proposed multi-agent system is able to find a sub-optimal target configuration in all cases. The solutions are the same as those obtained by the mathematical programming approach that the authors propose [11].

The contribution of this paper is summarized as follows:

- (1) A multi-agent system that consists of several *BAGs* and a single *FAG* for power system restoration is proposed.
- (2) With embedding simple negotiation strategies into *BAGs*, each *BAG* acts to find a solution autonomously by interacting with its neighboring *BAGs*.
- (3) From the simulation results it can be seen that the proposed multi-agent system is robust and effective, and may obtain the target configuration for large-scale restoration problems.

## 2. Power System Restoration Model

The objective of the mathematical model of a power system restoration is to maximize the capacity of the served loads:

$$\max \sum_{k \in R} L_k \cdot y_k \quad (1)$$

where  $L_k$  is the load of bus  $k$ ,  $y_k$  is the decision variable of whether  $L_k$  is restored or not ( $y_k=1$ : restored;  $y_k=0$ : not restored), and  $R$  is the set of de-energized loads.

The constraints associated with the restoration model are expressed typically as follows:

- (a) Limited capacity of the restorative-available power source:

$$\sum_{e \in F_q} P_e \cdot x_e \leq G_q \quad (q \in S) \quad (2)$$

where  $P_e$  is the power flow on the directed branch  $e$  (we assume  $P_e \geq 0$ ),  $x_e$  is the decision variable of whether branch  $e$  is included in the restoration paths or not ( $x_e=1$ : restoration path;  $x_e=0$ : not restoration path),  $F_q$  is the set of branches with starting node  $q$ ,  $G_q$  is the restorative-available power from the energized bus  $q$ ,

and  $S$  is the set of energized buses that can be connected to the de-energized area.

- (b) Power balance between supply and demand:

$$\sum_{k \in T_i} P_k - \sum_{k \in F_i} P_k - L_i \cdot y_i = 0 \quad (i \in N) \quad (3)$$

where  $T_i$  is the set of branches with ending bus  $i$ ,  $F_i$  is the set of branches with starting bus  $i$ ,  $L_i$  is the load of bus  $i$ , and  $N$  is the set of buses.

- (c) Limits in branch power flow:

$$|P_k| - U_k \leq 0 \quad (k \in B) \quad (4)$$

where  $P_k$  is the power flow of branch  $k$ ,  $U_k$  is the capacity of branch  $k$ , the  $B$  is the set of the directed branches.

- (d) Radial construction:

This constraint means that the target configuration must be constructed radially, and is used in the actual power system operations because of easy handling. To insure the radial configuration, the total number of branches that flow into bus  $i$  must be one or less.

$$\sum_{k \in T_i} x_k \leq 1 \quad (i \in N) \quad (5)$$

## 3. Multi-Agent Restoration Framework

In this section, we are going to develop a multi-agent architecture for power system restoration using the object-oriented design technique. Generally, it is important to realize efficient solution algorithms for power system restoration problems. To do this, we restrict the types of agents and the number of communications between agents. The proposed multi-agent restoration system is shown in Fig. 1. As shown in this figure, The proposed multi-agent system consists of several *BAGs* and a single *FAG*.

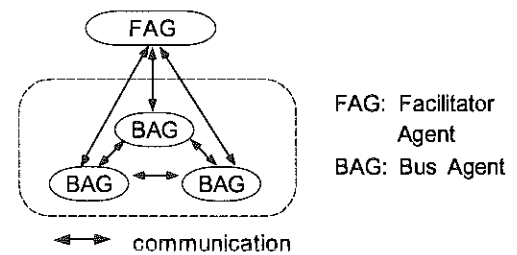


Fig. 1 Architecture of the restoration multi-agents system

### 3.1 Bus Agent (BAG)

The purpose of a *BAG* is to restore the load directly connected to its own bus. A *BAG* has simple rules for restoring the load:

- (i) If there are many restorative-available points or boundary points between the energized and

de-energized area, then the *BAG* has to restore its own bus through the restorative-available point with the maximum capacity.

- (ii) If the *BAG* is restored, the *BAG* tries to make a coalition with its neighboring *BAGs*.
- (iii) If the restorative-available power is insufficient to restore the load of the *BAG*, then the *BAG* makes a coalition with its neighboring *BAGs* and tries to energize the unserved load.
- (iv) If the load shedding is unavoidable, the *BAG* has to cut off the load with the minimum capacity.

When a fault occurs in the power system network, the *BAG* corresponding to the de-energized bus asks the *FAG* to restore its own bus. Usually, as there are many de-energized buses because of a fault, many messages are sent to the *FAG*. The first of these messages is the trigger of the proposed multi-agent system. When the *FAG* initiates the multi-agent system, the *FAG* sends a start message to the *BAG*. After the *BAG* receives the start message, the *BAG* starts directly communicating with other *BAGs*.

### 3.2 Facilitator Agent (FAG)

A *FAG* is a special agent that facilitates the process of the multi-agent system. First, the *FAG* classifies the de-energized buses into groups with the same voltage level. Then, the *FAG* selects one of the *BAGs* in the group with the highest voltage level, and sends a start message to the selected *BAG*. Since a start message is sent to a *BAG* in every de-energized group independently, the parallel processing is carried out to restore de-energized networks. In order to insure that only a single instance of the *FAG* exists at the same time, the singleton design pattern [18] is used.

### 3.3 Coalition Formation Between Bus Agents

Coalition formation is one of the key processes for the multi-agent system. In the following, we are going to describe what is a coalition in the restoration process, and how a *BAG* makes a coalition with other *BAGs*. For ease of understanding the coalition formation, we will explain the restoration process using the model network depicted in Fig. 2. We will use a simple example in the following section to demonstrate the performance of the proposed multi-agent system. It is assumed that the area enclosed by half-tone as shown in Fig. 2 has lost power because of a fault. Namely, the line between Bs/s and Ds/s is removed from the network because of a fault and the three loads are the elements to be resupplied:  $R=\{L2, L5, L6\}$ . In this situation, BUS3 and BUS9 have the restorative-available powers:  $S=\{BUS3, BUS9\}$ . A sequence of the coalition

formation is shown in Fig. 3. In this figure, the rectangular box with half-tone color corresponds to the de-energized *BAG*, while the rectangular box with white color corresponds to the energized *BAG*.

When the fault occurs, the following buses are de-energized: BUS5, BUS6, BUS11, BUS12, BUS13, and BUS14. The de-energized buses  $BUS_i$  are correspond to *Bus Agents*  $BAG_i$  respectively as shown in Fig. 3 (1). In this figure, the number in the parenthesis near  $BAG_3$  and  $BAG_9$  is the restorative-available power, and the number beside the rectangular box is the load of the *BAG*. After a fault occurs,  $BAG_{12}$  makes a coalition with  $BAG_{11}$  because it is able to energize from only  $BAG_{11}$ . The relation of  $BAG_{13}$  and  $BAG_{14}$  is the same situation.

Therefore,  $BAG_5$ ,  $BAG_6$ ,  $BAG_{11}$ , and  $BAG_{13}$  each send a message to the *FAG* in order to ask to restore their buses. The *FAG* saves these requirements to the de-energized bus list, named *DEBList*, selects the starting *BAG*, and sends a message to it to start communications for the restoration process.

In this case,  $BAG_5$  is selected, since  $BAG_5$  has the highest voltage level. If there is more than one available bus at the highest voltage level, *FAG* selects one of the *BAGs* that can be energized with the largest restorative-available power. Then  $BAG_5$  makes a coalition with  $BAG_3$  (Fig. 3 (2)), since the restorative-available power (2.0) is greater than the load at  $BAG_3$  (0.0). Next,  $BAG_5$  makes a coalition with  $BAG_6$  (Fig. 3 (3)). BUS6 has two neighboring *BAGs*:  $BAG_{11}$  and  $BAG_{13}$ . It is assumed that  $BAG_6$  tries to make a coalition with  $BAG_{11}$  first,  $BAG_{11}$  rejects the offer of the coalition (Fig. 3 (4)), since the current restorative-available power (1.0) is insufficient for the load downstream of  $BAG_{11}$  (2.0).  $BAG_6$ , therefore, tries to make a coalition with  $BAG_{13}$ , and the offer of coalition is accepted because of the sufficient restorative-available power. As  $BAG_{13}$  has no neighboring *BAG* except for  $BAG_{14}$ ,  $BAG_{13}$  gives the *FAG* notice that the process is terminated.  $BAG_6$  and  $BAG_5$  also send the termination message to the *FAG* (Fig. 3 (5)).

When the *FAG* receives the messages from  $BAG_{13}$ ,  $BAG_6$ , and  $BAG_5$ , it removes these *BAGs* from the *DEBList*. The *BAG* remaining in the *DEBList* is  $BAG_{11}$ . Then the *FAG* sends a starting message to  $BAG_{11}$ , the coalition formation is carried out in the same way as  $BAG_5$  (Fig. 3 (6)). After these coalition processes are completed, the target configuration for restoration is obtained as shown in Fig. 4. It requires two closing operations and one opening operation in order to restore all loads.

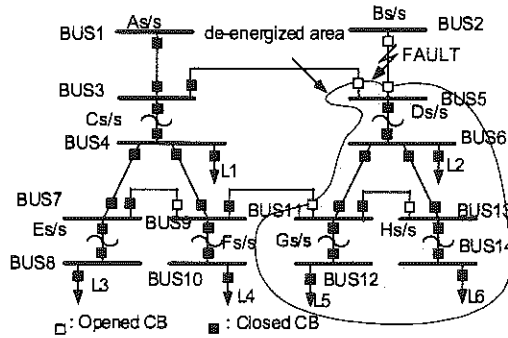


Fig. 2 An example of the post fault network

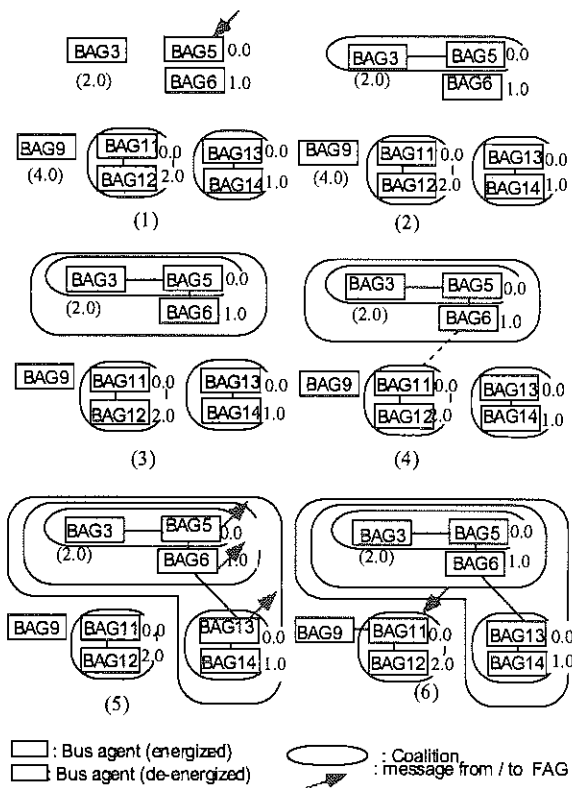


Fig. 3 An example of the coalition formation process

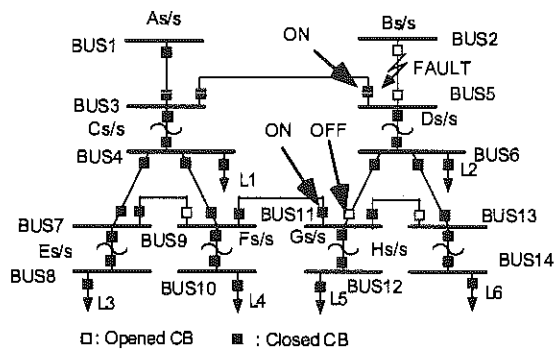


Fig. 4 A target configuration network for restoration

## 4. Simulation Results

### 4.1 Simulation condition

In order to demonstrate the effectiveness of the proposed method, it has been applied to a model network, shown in Fig. 5. The network consists of 8 substations and 14 buses. In this figure, As/s to Hs/s are substations and the arrows indicate the loads. The value of each load is displayed near the load. The labels on a branch show the line capacity (upper) and the power flow (lower). A black square (■) shows the closed status, and a white square (□) shows the opened status of the switching device. It is assumed that a fault has occurred at "X" and the half-toned buses and loads are de-energized. This restoration problem is difficult to solve because of the large variety of restoration possibilities. The computer used for simulations was a PC (550 MHz). The computer program was written in JAVA using JDK 1.1.

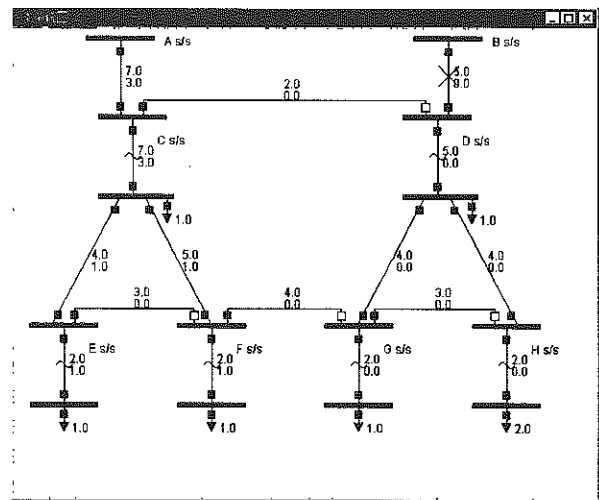


Fig. 5 Model network

### 4.2 Simulation results

A large number of simulations were carried out on this model network with changing conditions. Here, only three typical examples are shown due to page limitations. They are compared with the mathematical programming approach that the authors propose [11]. The results of all these cases are the same as those obtained from our mathematical programming approach.

#### (Case1) Full resupply of all loads:

This is a case in which all loads can be restored. The coalition process is the same as in section 3.3. In this

case, three switching operations (open : 1, close : 2) are required to restore all loads. Fig. 6 shows the simulation results. In this figure, the optimal target configuration network and the operation-sequence list are shown. The first two steps in the operation-sequence list correspond to the shedding of the line with a fault.

*(Case2) Partial resupplying of loads:*

This case corresponds to the case of heavy load conditions where the restorative-available power is less than the sum of the de-energized loads. This case is similar to case1, except the capacity of the line between Fs/s and Gs/s is decreased from 4.0 to 1.0. Fig. 7 shows the results. Although one load at Gs/s is unfortunately disconnected, this is the optimal solution under these condition. This case requires four switching operations (open : 2, close : 2).

*(Case3) Multiple outages:*

Next, let us consider a specific case: Double faults occur at different points at the same time. Fig. 8 shows the post-fault network. This case is similar to case 1, except the loads of buses 11 and 12 have been changed. In this case, since there are two de-energized bus groups {Ds/s, Gs/s, Hs/s} and {Es/s}, the restoration processes are started individually. Fig. 9 shows the simulation results. Six switching operations (open: 2, close: 4) are required to restore all loads.

From the results, it is proven that the proposed multi-agent system is able to find a sub-optimal target configuration in all cases. The solutions are the same as those obtained by the mathematical programming approach [11]. The calculation time is within two seconds in all cases. The value includes the time for synthesizing the operation sequence list.

## 5. Conclusions

In this paper, we have presented a multi-agent approach to power system restoration. The proposed multi-agent system consists of several *Bus Agents* (BAGs) and a single *Facilitator Agent* (FAG). A BAG has several simple restoration strategies and communicates only with neighboring BAGs, while the FAG acts to facilitate the decision process. That is, a BAG intends to conduct the local search, whereas the FAG intends to proceed with the global search. The validity and effectiveness of the proposed multi-agent system have been demonstrated by applying it to a model network. It is shown from simulation results that this approach is robust and effective. The next step of this work is to improve the multi-agent system's performance in order for it to cope with the difficulty of large-scale restoration problems. Future work should be directed

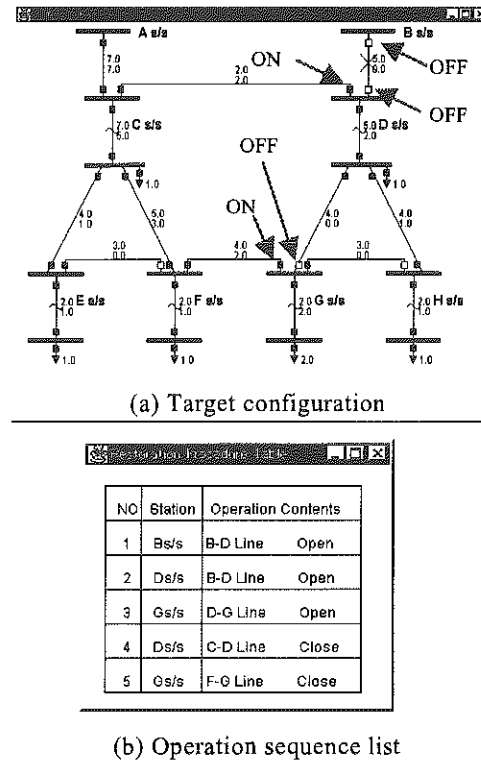


Fig. 6 Case 1: Full re-supply of all loads

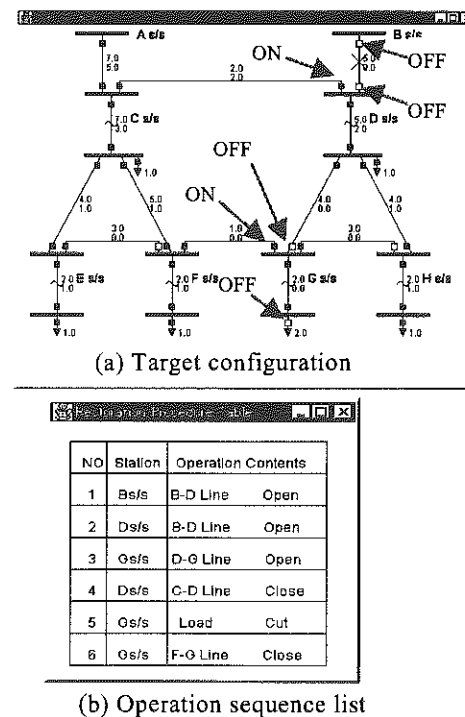


Fig. 7 Case 2: Partial re-supply of loads

towards expanding the proposed method to meet the requirements of the decentralized control environment, which has resulted from the world wide promotion of deregulation of electric power systems.

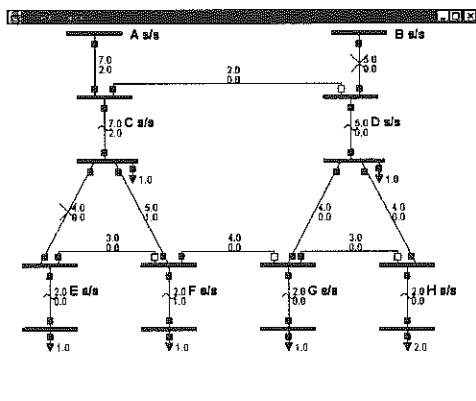
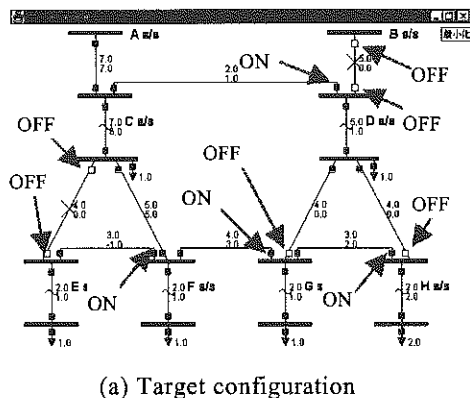


Fig. 8 Case3: Post-faults network



(a) Target configuration

| Restoration Procedure Table |         |                    |
|-----------------------------|---------|--------------------|
| NO                          | Station | Operation Contents |
| 1                           | Bs/s    | B-D Line Open      |
| 2                           | Ds/s    | B-D Line Open      |
| 3                           | Cs/s    | C-E Line Open      |
| 4                           | Es/s    | C-E Line Open      |
| 5                           | Gs/s    | D-G Line Open      |
| 6                           | Fs/s    | E-F Line Close     |
| 7                           | Gs/s    | F-G Line Close     |
| 8                           | Hs/s    | D-H Line Open      |
| 9                           | Ds/s    | C-D Line Close     |
| 10                          | Hs/s    | G-H Line Close     |

(b) Operation sequence list

Fig. 9 Case3: Multiple outages

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## Discussions on

### Session IX: STABILITY ASSESSMENT & RESTORATION

#### Part 2

**Chairman:** So we are now starting the last discussion time of this meeting. We had ISO operator and new multi-agent technique. Some questions or comments?

**T. Overbye:** I have a question for Dr. Nagata. On an agent restoration, I understand the need for the BAGS, but could you without the FAG in it or there is a communication between the BAG and the FAG, and the BAG still knows what to do without the FAG?

**T. Nagata:** Your question is concerning the data communication. We have used kind of KQML like protocol.

**T. Overbye:** But I can't understand the difference between what you're proposing and kind of centralizing device control.

**T. Nagata:** Yes. The facility in my system is like centralized. I think it is a drawback of my system, because all information is gathered to the facility. Then what we can do is to remove the facilitation from our multi-agent system.

**P. A. Lof (ABB):** I have a question for Dr. Nagata. It's concerning the load and during the simulation that start this?

**T. Nagata:** I'll try to respond. This is an objective oriented programming technique. This local information, as a local information, this rules are installed.

**C. C. Liu:** I have two questions. One is about the team structure with the negotiation method you have. I think you have a team structure with agents that are able to do something, but the system-wide objective is not very clear. Also how can all the BAGS together with the FAGS achieve that goal? That seems to be an open question to me. I want the multi-agent system to achieve the minimum amount of time, how do you achieve it with your structure? It seems that you make it more autonomous or de-centralized.

**T. Nagata:** I didn't talk about this but the buses and the transformer at the lower level bus make an inquiry to the upper level bus, so the communication is limited to upper, higher voltage level bus.

**C. C. Liu:** About the motivation of multi-agent system here, have you evaluated the multi-agent structure with respect to the algorithms that are available? The question is why is the multi-agent structure better than other

methods? Or have you done any comparison?

**T. Nagata:** In our deregulation, the generation sector is like this. On the other hand, transmission and distribution sectors are kept.

**N. Kakimoto:** It is a concern with the geothermal power plant. In Italy there are many and it was very interesting. I'm not familiar with it.

**M. Paolone:** There is a particular situation with regard to the geothermal power plants. They are located in a particular geographic point. These plants don't have blackstart capability. The paper focuses on the combined cycle, in which the gas turbine and the steam in one generator. In Italy we have a different situation to give us a possibility to disconnect the section of the steam power plant and to give the blackout capability.

**J. P. Paul:** Last question for our Italian colleague. If you could state more precisely about the restoration, because in my mind, the restoration is such a catastrophic situation to restore, so I don't see why it is revisit the restoration plan?

**M. Paolone:** There is the possibility to make other kind of contracts. These contracts include the capability of all plants to have each GENCO and the ISO role needs to have supervision in the restoration phase in order to accomplish this system. This is complicated. Our university group fixes the rules actually, especially for the restoration. But the possibility to have this kind of contracts and to evaluate the price of the blackstart capability of the plants, to weigh it economically, from the economical point of view, the capability is one of the problems.

**Chairman:** It's time to close this session. Thank you.

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