Analysis and Visualization of Market Power in Electric Power Systems

Thomas J. Overbye Jamie D. Weber Kollin J. Patten
overbye@ece.uiuc.edu jd-weber@uiuc.edu kpatten@uiuc.edu
Department of Electrical and Computer Engineering
University of Illinois at Urbana-Champaign
Urbana, IL 61801

Abstract

This paper discusses the assessment and visualization of market power in bulk electricity markets, with the explicit consideration of transmission system constraints. In general, market power is the ability of a particular seller or group of sellers to maintain prices profitably above competitive levels for a significant period of time. When an entity has and exercises market power, it ceases to be a price taker and becomes a price maker. The restructuring of the electric industry in many parts of the world has encouraged competitive markets with the objective of reaping the benefits of lower prices and innovation that competition can provide. Such benefits are not attainable when a player utilizing the electric transmission system may exert market power. This paper describers the procedures for analyzing and visualizing such situations.

1. Introduction

The electric power industry throughout the world is in a period of radical and rapid restructuring, with the traditional paradigm of the vertically integrated electric utility structure being replaced by competitive markets in unbundled electricity services with disaggregated structures. In the United States the Federal Energy Regulatory Commission (FERC) issued its Order 592 "Policy Statement on Utility Mergers" in December of 1996 [1] with the explicit objective of streamlining and expediting the processing of merger applications in the new competitive environment. The central focus of this policy is on the "effect on competition" of proposed mergers. FERC's formal adoption of the Department of Justice/Federal Trade Commission (DOJ/FTC) *Horizontal Merger Guidelines* [2] as the framework for competition has triggered a strong interest in the analysis of market power issues in electricity markets. The same guidelines appear in the more recent FERC proposed rulemaking [3].

Market power is the antithesis of competition. It is the ability of a particular seller or group of sellers to maintain prices profitably above competitive levels for a significant period of time. When an entity has and exercises market power, it ceases to be a price-taker and becomes a price-maker. The ambitious restructuring of the electricity industry has as its goal to reap the benefits of lower prices and innovation resulting from the establishment of competitive marketplaces for electricity products and services. This drive to competition is being accompanied by the unbundling of services and the disintegration of the vertical structures of the industry.

However, this drive to competition has also given rise to significant concerns that the potential benefits resulting from the breaking of the vertical market power of the traditional utility could, in time, be supplanted by the establishment of horizontal market power. Events during the week of June 22, 1998 on the U.S. Midwest electrical system indicate that the potential impact on prices could be substantial. As reported in [4], during periods of heavy loading, spot prices in the Midwest soared up to \$7,500 per MWhr, over 100 times the average energy price.

The restructuring in electricity markets and the issuance of the FERC *Merger Guidelines* have brought about intense interest in the study of market power issues in the electricity industry [5], [6], [7]. Most studies of market power review the structure, conduct, and performance of a market. However, significantly less work has been done to investigate the key impact the transmission system has on market power issues.

The objective of this paper is to provide an overview of the impact that the electrical transmission system has on the analysis of market power issues, with particular emphasis on the impacts of transmission congestion. Additionally, given the complexity of the issue, an important component of this work is effective visualization of the issues involved in market power analysis, particularly with regard to the analysis of large systems. The paper discusses several pertinent visualization ideas, including contouring and the use of virtual reality data visualization.

2. Market Power Analysis in Electricity Markets

The analysis of market power typically involves the following steps [1]:

- Identification of the relevant products/services
- Identification of the relevant geographic market
- Evaluation of market concentration

For market power analysis in electricity markets FERC has typically considered at least three distinct products, non-firm energy, short-term capacity (firm energy), and long-term capacity. Product groupings are allowed when the products are reasonable substitutes for each other from the buyer's perspective. As restructuring progresses the emphasis appears to be shifting from the long-term capacity market to the short-term energy markets [3]. Therefore, the emphasis of this paper will be on the short-term energy markets. The challenge in performing this analysis is that electricity demand varies substantially over time, and, of course, there are few economic means for storing this energy. This requires analysis for a variety of different market conditions.

The second and by far the most difficult step in performing market power analysis for an electricity network is the determination of the geographic scope of the market for the product. In our definition the market is based on the capability of a supplier, say a generator, to deliver the product/service to a buyer, say a load. The size of the electricity markets is dependent upon both the physical/operational characteristics of the transmission network used to enable the movement of electricity from the supplier to the customer, and the impacts of the services in transporting this energy, including any prices charged. These issues are the key focus of this paper, and will be discussed in-depth.

A key step in performing market power analysis is the analysis of market concentration. A commonly used methodology is the Herfindahl-Hirschman index (HHI) [8], defined as:

$$HHI = \sum_{i=1}^{N} q_i^2 \qquad (1)$$

where N is the number of market participants and q_i is the percentage market share of each participant. Hence, the HHI for a monopoly would be $100^2 = 10,000$, while HHI would be a small number when N is large and no participant has more than say 5% market share. Under DOJ/FTC standards for horizontal market power [2], post-merger values of HHI under 1000 are considered to represent an unconcentrated market that are unlikely to have adverse competitive effects. Post-merger values between 1000 and 1800 are considered to be moderately concentrated. Values above 1800 are deemed to be highly concentrated; mergers increasing the HHI by more than 100 points are viewed as likely to create or enhance market power.

3. Market Power Analysis without Transmission Considerations

For electricity markets, the appropriate definition of the market is critical. Clearly both physical factors – the transmission network and its operation – and economic factors – the market structure and its rules – are determining elements in this definition. To motivate this discussion, initially consider the case in which the transmission system is not explicitly considered and no transportation charges are incurred in moving power from the generator to the load. Without explicit consideration of the transmission system there is a tacit assumption that each MW of generation could reach any desired load location, or conversely that each MW of load may use as a source of supply any generator within the interconnected system. The degree to which any single producer can exercise market power depends then solely on its concentration of ownership relative to that of the other producers for the entire interconnected system.

For such systems, calculation of the HHI values is straightforward. For example in North America the HHI values can be calculated using data from the NERC (North American Electric Reliability Council), which lists generation capacity for both the winter and summer peaks. Using 1997 data (average of summer/winter peaks) the Eastern Interconnect had a total capacity of 593 GW with about 650 different market participants. Without any consideration of the transmission network, the associated HHI for the Eastern Interconnect is about 170. Clearly for this conceptual case, completely ignoring consideration of transmission system constraints and transportation charges, no market power exists. Mergers between even the largest utilities in the Interconnect would not substantially affect this value. Similar values for each of the NERC Reliability Councils are reported in [7].

Of course, neglecting the transmission system and its associated charges is usually inappropriate, particularly for a large system. To aid in determining the appropriate geographic market of potential suppliers to a particular customer, FERC requires that the suppliers must be able to reach the market both economically and physically. The FERC economic criteria require that a supplier must be able to deliver to a customer at a cost no greater than 105% of the competitive price to that customer. The delivered cost is the sum of the variable generation cost, and the transmission and ancillary service charges. Therefore the market size is dependent upon the particular mechanism used for transmission pricing.

Several mechanisms are used for pricing transmission services, with a recent survey found in [9]. Whenever there are a number of transmission providers whose services are used to get delivery of power/energy from a designated source to a designated sink, the "pancaking" of the transmission charges of each provider may occur. The net effect of these pancaked rates is to limit the size of the market since more distant suppliers incur increasingly larger transmission charges. The move away from pancaking is big motivator for the establishment of the so-called Independent System Operator (ISO). The ISO is a control entity that is the sole operator/controller of the transmission system in a specified region. Under the eleven ISO principles promulgated by FERC in its Order No. 888, a single rate for the interconnection supplants the various tariffs of the transmission providers. The establishment of an ISO and its accompanying "postage-stamp" pricing mechanisms have the desirable impact of enlarging the seller's and/or buyer's potential market in a given region, effectively lowering the HHI.

4. Market Power Analysis with Transmission Constraints

Market size can be limited not only by economics, but also by the physical capability of the transmission system. A key issue to be addressed is how to incorporate the impact of the transmission system and any consequent congestion. Congestion arises because the capacity of the transmission system has a finite but usually not easily determined value. That is to say, the ability of the transmission system to support additional power transactions is limited by the need to maintain system security. Transmission system capacity is limited due to a number of different mechanisms, including transmission line/transformer (line) limits, bus voltage limits, transient stability constraints, and the need to maintain system voltage stability. Here we just consider the impact of line limits, but the incorporation of bus voltage limits is relatively straightforward. Other limits could be directly incorporated if they can be recast in terms of line/flowgate limits. A line is said to be congested anytime it is loaded at or above its MVA limit.

The simplest case illustrating the impact of the transmission system in market power analysis is the radial single bus system modeled in Figure 1. Here the load at bus A can be served either by local generation at bus A, or through the single transmission line joining bus A with the rest of the electric system. The pie chart in the line shows the percentage loading on the line; here the line is loaded at 100% of its rated capacity so the pie chart is completely filled-in, with the arrows indicating the direction of flow [10]. Because of this 100 MVA flow limitation on the line the generator at bus A has complete market power anytime the load at the bus exceeds 100 MW. That is, in the short-term the only option available to the customers receiving energy at bus A is to pay the price charged by the bus A generator, or to do without. Hence the number of participants in the generation market available to the bus A "load pocket" is effectively one. Hence the effective HHI is 10,000. Note that this limitation is completely independent of generator costs and transmission tariffs. Of course, if the load is variable, such market power is only present when the bus A load exceeds the line's import capacity.

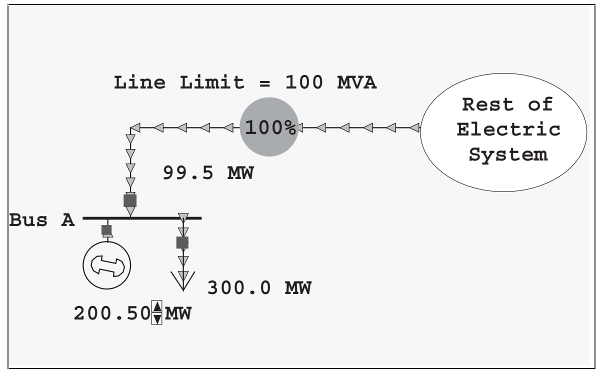

Figure 1: Radial System with Market Power

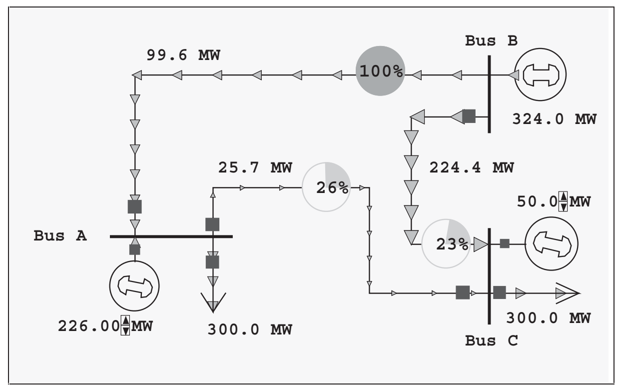

Figure 2: Three Bus Example with Import = 74 MW

If a second line is added between bus A and the rest of the system, the situation becomes substantially more complex. Bus A is no longer radially connected to the remainder of the network, but is now an integral part of the network. A key point in performing this analysis is that the maximum power that can be imported into the bus A load pocket is not (in general) equal to the sum of the limits of the two lines joining it with the remainder of the network. Rather, this sum only provides an upper limit. The actual import limit depends upon both the impedance of the remainder of the network, and the particular power flows in that network. The interface (i.e., all of the lines joining bus A to the rest of the system) is congested anytime either of the lines reaches its limit. The import limit can actually be less than the individual line limits. Such a situation is illustrated in Figure 2 for a simple three bus system in which 25 MWs is being "wheeled" through bus A, decreasing its import capability to about 74 MW, below either of the 100 MVA line limits. An important point for such a networked case is that the ability of bus A to import or export power depends strongly upon conditions in the rest of the electrical system.

For the generalized case, define the area A load pocket as the set of loads, possibly located at multiple buses, that buy power in aggregate and hence are subject to similar (or identical) pricing. Examples of load pockets could be a municipality without sufficient internal generation, a cooperative system, or a load aggregator. The load pocket is then connected to the remainder of the interconnected system through a set of transmission lines. The degree of market power enjoyed by a set of commonly owned generators (i.e., a portfolio of generators) with respect to serving the area A load pocket depends upon the generation market available to area A. This in turn depends upon the characteristics of the transmission system, including its present level of loading.

Our approach to determining the generation market available to a particular load pocket starts with results provided by the Simultaneous Interchange Capability (SIC) algorithm. SIC seeks to quantify the amount of power that can be imported into a particular load pocket. Determination of SIC is thus an optimization problem whose objective is to determine the generation dispatch that maximizes the amount of power that can be imported into the load pocket. Linear load flow and linear programming solutions have made SIC calculation relatively fast and easy [11-15] when appropriate assumptions are made concerning the response of the affected generation. If assumptions are made that all generators respond in such a way to maximize the interchange value, the SIC provides an upper bound on power import. For the Figure 2 three bus system the SIC value is 200 MW, which is achieved when bus B generation is 200 MW and bus C generation is 300 MW. However the SIC solution is not identical to solving the market power problem. The key difference lies in the assumptions concerning the response of the generators – in a competitive marketplace all generators will certainly not respond in a way to maximize import. While some generation portfolios may indeed be working to maximize the import into the load pocket, others may actually seek to minimize this value to enhance their ability to exploit market power.

In order to understand the potential implications of this behavior on market power analysis, two interrelated issues must be discussed. First, in a networked transmission system the incremental changes in the amount of power generated and/or consumed at a set of buses can result in changes in the power flow throughout a large portion of the network. That is, a power transfer through the system can potentially impact other parties not involved in the transfer; this is commonly referred to as "third party impacts" or "loop flows". How the power distributes through the system depends upon the particular direction considered, as well as on the characteristics of the transmission system. This incremental change in flows associated with a particular direction has been defined by NERC as the power transfer distribution factors (PTDF)s. The PTDF values provide a linear approximation of how the power flows would change for a particular power transfer between different pairs of generation portfolios and load pockets.

The second issue is that whenever a line or interface is congested, the system's ability to support additional power transfers can be limited, even for directions remote from the point of congestion. Which directions are limited depends upon whether a transfer would increase or decrease loading on the congested line.

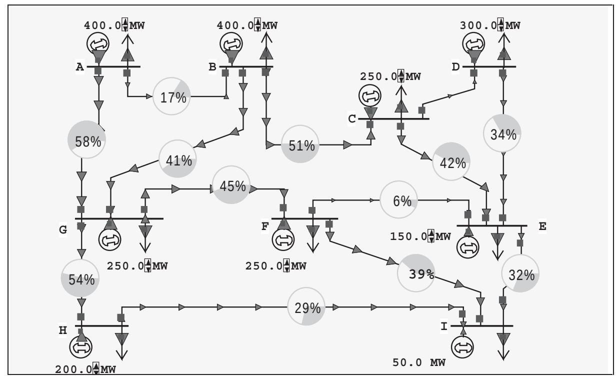

Figure 3: Nine Bus Base Case Flows

To illustrate these two issues, consider the nine bus system shown in Figure 3. For simplicity this system has been designed with the following characteristics:

1. Each bus has a single generator with a capacity of 500 MW and a single 250 MW load,
2. Each bus initially corresponds to a single market participant (a single operating area),
3. All transmission lines have impedance of j0.1 per unit and a limit of 200 MVA.

Each area is assumed to be controlling its interchange, with several initial base case transactions modeled as shown in Figure 3. For this case, the SIC value is greater than the load at each bus. Therefore as a starting point we'll assume that each load can buy from any of the nine generators. Thus the effective market encompasses the entire system, allowing for straightforward calculation of the HHI index (using generator capacity). Each of the 9 participants has 11.1% market share resulting in an HHI of 1110, indicating no market power.

Starting from the base case flows, the PTDF values can be used to provide a linear approximation of the impact caused by a proposed power transfer from a source to a sink. Note that while the PTDF values are only a linearized approximation, this approximation is usually valid over a wide variation in operating points. As an example Figure 4 shows the PTDF values for the 9 bus system for a proposed power transfer from bus A to bus I (to reduce clutter the buses/generators/loads are now shown as just an ellipse). The pie chart values now show the PTDF values, expressed in terms of a percentage of the power transfer amount. Figure 4 indicates that 44% of the transaction flows along the transmission line from bus A to

B, while 35% flows from G to F. The change in flow along the particular path is then the PTDF value multiplied by the power transfer. Thus, a 50 MW transfer from A to I increases the MW flow from A to B by about 50 * 44% = 22 MW. The PTDF values for a transfer from G to F are shown in Figure 5. Note that the PTDF values for both cases indicate that the transfers would have a significant impacts on almost all of the transmission line flows. Present NERC line loading relief criteria deem any transaction having a PTDF value of greater than 5% on a limiting element as having a significant impact on the element's flow.

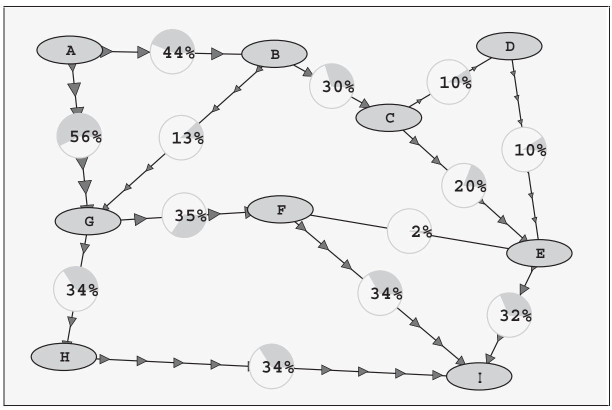

Figure 4: PTDF Values for Transfer from A to I

The PTDF values can also be used to help estimate the maximum amount of power that can be transferred on a particular direction (i.e., a specified source/sink pair) [16]. This value is determined by recognizing that for a direction j the real power flow on any line i, P_i, due to a transaction in direction j can be approximated as

$$P_i = P_{i0} + d_{ij} P_{Tj} \tag{2}$$

where d_{ij} is the PTDF for line i in direction j, P_{i0} is the base case flow on the line, and P_{Tj} is the magnitude of the proposed transfer. If the limit on line i is $P_{i\ max}$, the maximum power that can be transferred in direction j without overloading line i is

$$P_{Tj\ max\ i} = \frac{P_{i\ max} - P_{i\ 0}}{d_{ij}} \tag{3}$$

The maximum value of $P_{Tj\ max}$ that can be transferred without overloading any line in the set consisting of all lines in the system, Λ, is then

$$PT_{Tj\ max} = \min_{i \in \Lambda} \left[\frac{P_{i\ max} - P_{i\ 0}}{d_{ij}} \right] \tag{4}$$

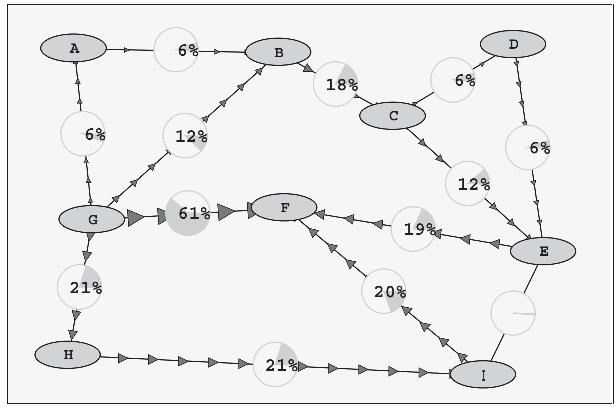

Figure 5: PTDF Values for Transfer from G to F

With the nine bus case the maximum transfer from A to I is actually limited by minimum generation in area I. If this constraint is ignored, the maximum allowable additional transfer is 148 MW; the limiting element will be the line from A to G. The maximum for the G to F transfer is about 94 MWs, with the line from G to F the limiting element.

Table 1: Line G to F PTDF Values

Seller/Buyer (Direction)	Line G to F PTDF
A to I	35%
B to I	29%
C to I	11%
D to I	5%
E to I	-1%
F to I	-20%
G to I	41%
H to I	21%

PTDF calculations are important to consider in market power analysis because operating practice forbids the initiation of new transfers that register a significant PTDF on the congested line or interface, in the direction such that the transfer would increase the loading on the congested element, where significant is often quantified as a PTDF in excess of 5%. For example, for the nine bus system Table 1 shows the PTDF values for line G-F (with flow from G to F assumed to as positive) for different suppliers sending power to the I load pocket. Thus if congestion were present on the line from G to F, the number of sellers that have access to the bus I load pocket is significantly decreased [17]. For such a case area I consumers could only buy from areas I, E and F. Therefore the resultant market power index for area I is now 3 * 33.3^2 = 3327, indicating significant market concentration.

Results from [18] show that for markets with such small numbers of producers optimal bidding strategies require bids substantially above the producers marginal costs. Note though that this market power only exists when the line is congested. Also, this congestion is one-sided. When the direction is reversed the PTDF values simply change sign[i]. Therefore generation in I can sell to all other areas except for F.

6. Strategic Market Power

The fact that transmission congestion can limit market size creates the possibility that owners of portfolios of generators could deliberately dispatch their generation in order to induce congestion for strategic purposes [17]. For example again consider the Figure 3 nine bus case. Initially this system has an apparent HHI of 1110, indicating no market concentration. Now assume that areas F and G merge, creating area FG, which now has a 22.2% market share. The other seven participants still have a 11.1% share, resulting in an apparent HHI of only 1355. However with geographically dispersed generation FG now has at least some ability to unilaterally "manipulate" the flows throughout the system and hence the potential to deliberately induce congestion for strategic purposes.

To quantify this potential, we first examine the ability of a particular set of generators with common ownership to unilaterally control the flow of power on various lines. Assume a set of N generators is currently producing some total base case output and that the generators' owner is free to control their dispatch. Hence the generators could be re-dispatched in such a way to modify the flow on a particular line i, provided the net change in generation is zero. Therefore the maximum ability of this set of N generators to unilaterally control the flow on a particular line i can be formulated as a maximization problem,

$$\max \Delta P_i \;=\; \sum_{k=1}^{N} d_{ik}\,\Delta P_k \qquad \text{s.t.} \qquad \sum_{k=1}^{N} \Delta P_k \;=\; 0 \qquad (5)$$

where d_{ik} is the sensitivity of the line i power flow to a 1 MW increase in the bus k generation, ΔP_k is the change in the bus k generation, and ΔP_i is the change in the flow on line i. For convenience, we define this value as the Unilateral Line Control Factor (ULCF). The ULCF for line i is maximized by increasing the generators with the most positive d_{ik} and decreasing those with the most negative values, subject to generator maximum/minimum MW limits. Hence the ability of a portfolio of generators to unilaterally control flows depends upon the number and capacity of the generators in the portfolio, and their geographic location within the transmission system.

For the merged two generator FG area, with $\Delta P_F = -\Delta P_G$, (5) reduces to

$$\mathrm{ULCF}_i \;=\; d_{iF}\,\Delta P_F - d_{iG}\,\Delta P_F = \Delta P_F\,(d_{iF} - d_{iG}) \qquad (6)$$

where the flow sensitivity values, $d_{iF} - d_{iG}$, are shown in Figure 5. Starting from the Figure 3 base flows and a maximum allowable change of ΔP_F of 250 MW, the implication is area FG can unilaterally induce congestion on line G-F, and hence block areas A, B, D and H from the area I market. The percentage line loadings for this scenario are shown in Figure 6. FG can still sell into the area I market because generation at F is not blocked.

A market participant's physical ability to create congestion depends upon the mechanism used to obtain transmission access/dispatch generation, the portfolio of available generation, and the current system operating point. From FG's point of view, the best mechanism for transmission access/generation might be one in which it had complete priority in access to transmission line G to F, such as that given a utility when serving its native load. At the other end of the spectrum might be a bid-based ISO. However even with such an ISO, area FG could still devise a bidding strategy which allowed it to achieve congestion on line G to F, and hence sell into a relatively constrained area I. The success of such a strategy would, of course, dependent upon expected system loading.

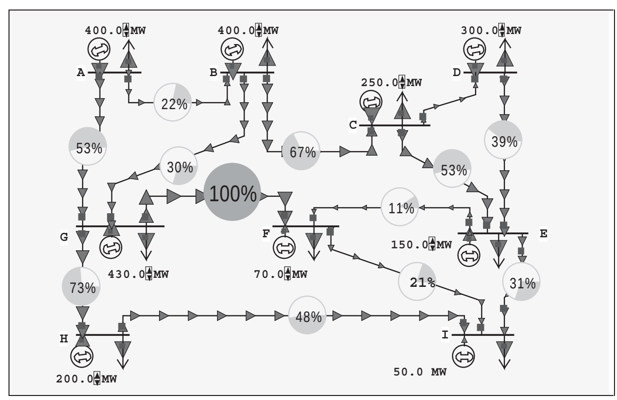

Figure 6: Area FG Blocking Area I Market

A strategy of deliberately creating congestion could certainly involve additional cost to the congestor, with the exact value dependent upon how far it must deviate from an economic dispatch. The increase in profit is then the difference between the additional income gained from the congestion and the costs incurred in creating the congestion. The congestor would only pursue such a strategy if they had a reasonably good expectation of profit. However as was mentioned in the introduction, events during the Summer of 1998 indicate that such profits could be substantial. From a long term perspective market participants should certainly be cognizant in procuring their generation portfolios of both their own, and the ability of their competitors, to engage in such strategic behavior. Likewise those involved with devising market

[i] In general this is true only for a lossless system, such as the one considered here, with no active single-sided limits (such as generator MW limits or transformer phase shifter limits).

rules, approving generation portfolios, and policing the system, must also be aware of such strategic behavior.

7. Market Power Assessment

Assessment of market power requires determination of the generation market available to each load pocket, or conversely, the load market available to each generation portfolio, taking into account the potential for strategic behavior by one or more market participants. Thus the problem has two sets of players, those who are seeking to sell to the load and hence will try to maximize the power transfer to the load pocket (the Maximizers), and those seeking to prevent others from gaining access to the load (the congestors or the Minimizers). An exact solution to this problem would require a noncooperative game theory approach in which the two players simultaneously seek the best possible outcome assuming the worst possible choice by the other [19]. A direct solution to this problem could be computationally taxing, particularly for large systems.

Here we propose to approximate this solution by solving the SIC problems with simplified assumptions about the impact of the congestors. Once a set of congestors has been specified, the ULCF results of (5) could be used to derate the limits on each line i by the amount $ULCF_i$. Please note that $ULCF_i$ is the maximum amount by which the congestors can unilaterally manipulate the flow on line i. If the SIC problem is solved using these assumptions, the results provide the minimum amount of power that can be imported into the load pocket. The reason this value is a minimum is because the congestors could not simultaneously modify the flow on all the affected lines by that line's maximum amount $ULCF_i$.

As an example, Figure 7 again shows the Figure 6 case of area FG attempting to block the import of power into I from other areas. Here the line limits were first derated using (5). Results of these derated limits are shown in Table 2. The SIC algorithm was then solved using the derated limits with the assumptions that all the other generators in the system (i.e., all but the generators at F and G) are redispatched so as to increase the net import of power into area I. SIC results are shown in Table 3.

Note that the Figure 7 results differ from those of Figure 6. In the Figure 6 case the assumption is that FG initially congests the line from G to F; subsequently the only areas that can sell into area I are those with negative line GF PTDF values. This is analogous to the case where each area independently dispatches its generation. In contrast, in the Figure 7 case the system is assumed to be dispatched simultaneously, analogous to what might occur in an ISO. Area I could now receive at least some power from Areas C and D as well as from Areas E, F and G.

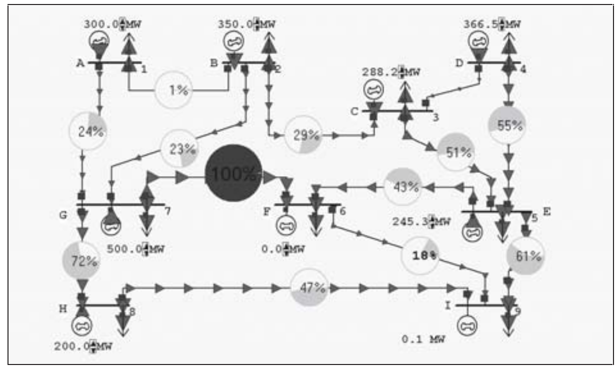

Figure 7: Nine-Bus System with Congestion from G to F

Table 2: Derated Line Limits

Line	Limits	ULCF	Derated Limits
A to B	200 MVA	15 MW	185 MVA
A to G	200 MVA	15 MW	185 MVA
B to C	200 MVA	45 MW	155 MVA
B to G	200 MVA	30 MW	170 MVA
C to D	200 MVA	15 MW	185 MVA
C to E	200 MVA	30 MW	170 MVA
D to E	200 MVA	15 MW	185 MVA
E to F	200 MVA	47 MW	153 MVA
E to I	200 MVA	2 MW	198 MVA
F to G	200 MVA	153 MW	47 MVA
F to I	200 MVA	50 MW	150 MVA
G to H	200 MVA	52 MW	148 MVA
H to I	200 MVA	52 MW	148 MVA

Table 3: SIC Results for Figure 7 Case

Generator	Change
Export from Area A	0 MW
Export from Area B	0 MW
Export from Area C	38.2 MW
Export from Area D	66.5 MW
Export from Area E	95.3 MW
Export from Area H	0 MW
Import into Area I	200 MW

8. Large System Visualization

While the previous issues were demonstrated using a small system, they are certainly applicable to practical cases of any size. An example of a larger case is the 1998 ECAR FERC 715 case, which contains a very good representation of the transmission system in the Eastern Interconnect, with over 30,000 buses, 5000 generators, 41,000 transmission lines/transformers and 130 control areas [20]. A portion of the high voltage transmission system for this system is shown in Figure 8. The potential for strategic market power situations can be seen by noting the extensively large number of loops in the system. The presence of congestion involving only small portions of the system may result in the cancellation of a large number of transactions. An important additional issue is that with thousands of transmission dependent utilities, such as many municipal, cooperative systems and in the future perhaps load aggregators, market power needs to be assessed not just for the system as a whole, but also for the thousands of individual "load pockets" that these systems represent.

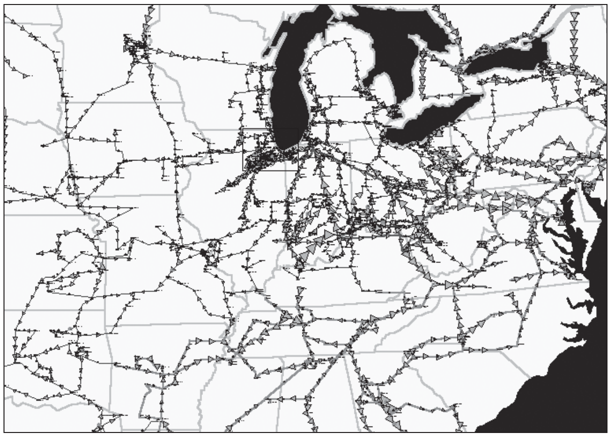

Figure 8: High Voltage Transmission System Flows in Eastern North America

A difficulty in analyzing such large systems is to relatively quickly convey to the user information about system loading, and hence the potential for market power abuse. Here we present several visualization techniques for addressing this issue.

The first technique for quickly indicating the loading of a large network has been the use of dynamically sized pie-charts to indicate loading on each transmission line. As an example, Figure 9 again shows the Figure 8 system with pie-charts used to indicate the loading on each transmission line. The percentage fill in each pie-chart is equal to the percentage loading on the line, while the size and color of the pie-chart can be dynamically sized when the loading rises above a specified threshold. For example assume in the Figure 2 case the user was only concerned with those lines at or above 70% loading. By specifying that the pie-chart increase in size by a factor of 5 if above 70% or a factor of 7 if above 80%, it is easy, even in a large system, to see the heavily loaded lines.

Using pie charts to visualize these values is helpful, but this technique also runs into difficulty when a large number of pie charts appear on the screen or in situations where the fill-in on each pie chart is small. To remedy this problem, an entirely different visualization approach was investigated: contouring. Contouring has, of course, long been used for the display of spatial data, with the newspaper temperature contour maps one well known example. Application of contouring to power system voltage magnitudes and line flows has been previously discussed in [21] and [22]. An example of a line flow contour is shown in Figure 10. Key to effective use of line flow contours is to only show those line flows loaded above a specified percentage. This is akin to a TV radar image in which only areas of precipitation are shown. In the Figure 10 case only those lines loaded above 50% are highlighted.

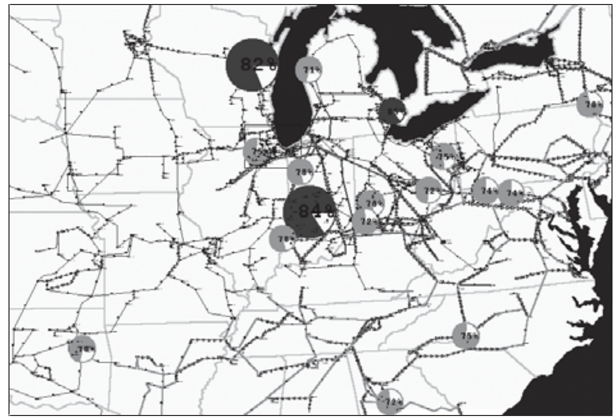

Figure 9: Pie Charts Showing Line MVA Percentages

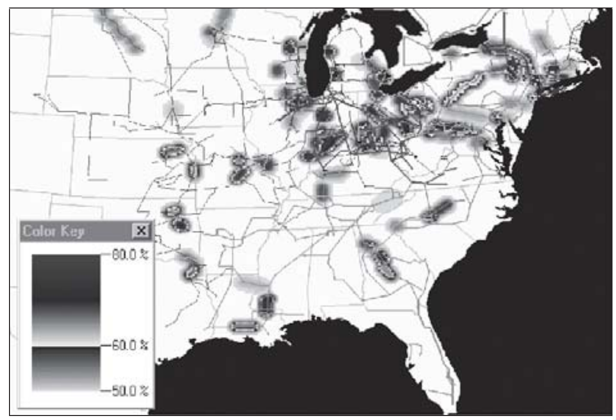

Figure 10: Percent MVA Percentage Contours

Additional uses of contouring could be to show the PTDF values associated with a particular power transfer or the ULCF values for a particular portfolio of generators. For example, Figure 11 shows a contour of the PTDF values associated with a power transfer between Southern Company to the New York Power Pool. Note that the power flows spread throughout a large portion of the system. Overall for this transfer about 280 lines have PTDF values above the 5% threshold. While this is a small fraction of the 41,000 lines in the case, the impacted lines tend to be the high voltage lines that would be used by numerous transfer directions.

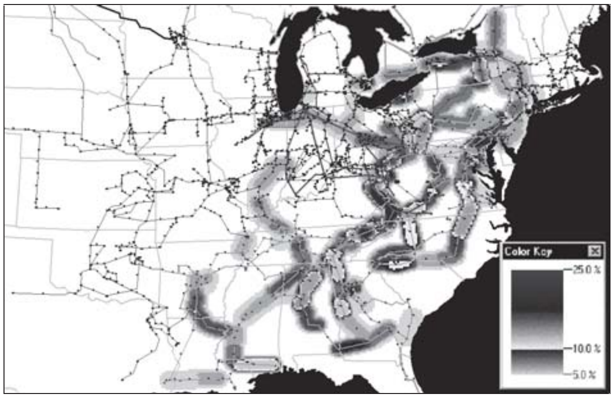

Figure 11: PTDFs for Transfer from Southern to NYPP

9. Virtual Reality Data Visualization

The previous data visualization techniques can be quite useful when one is primarily concerned with visualization of a single type of spatially oriented data, such as transmission line voltages or bus voltages. However often in power systems the relationships between a number of layered systems need to be considered. A pertinent example could be the relationship between the actual transmission system flows and the PTDF values associated with a proposed transaction. Here we provide some initial results on the use of virtual reality to visualize such systems.

Virtual environments, or virtual reality (VR), provide a fully three-dimensional interface for both the display and control of interactive computer graphics [23]. Thus the main idea behind VR systems is to give the user the feeling that they are immersed in a three-dimensional world, populated by computer generated objects. The most compelling illusions are achieved through the use of wide-field-of-view strereoscopic head-tracked display systems [24]. The use of VR for operator-training in power systems is described in [25] and [26].

For the results presented here, PowerWorld Simulator [27] was modified to allow three dimensional drawing and interaction using OpenGL. OpenGL itself is a software interface, originally developed by Silicon Graphics, for graphics hardware that facilitates the modeling of three-dimensional systems [28]. Similar to [26], the PowerWorld Simulator implementation uses a regular PC type display to provide a less-ambitious, but nevertheless quite compelling virtual world. Key to achieving a virtual reality illusion is to provide the user with the ability to move about freely in three dimensions, and to look in any desired direction.

As an example, Figure 12 shows a one-line for a thirty bus, except with the modification that the one-line has been mapped into a 3D view, and that bus "height" and color is now proportional to the bus voltage magnitude. When the simulation is running, flows on the transmission lines are also animated. By moving about in this virtual world, the user begins to feel more as if he/she is within the one-line, rather than just looking at it. This allows the potential to gain a much better intuitive appreciation for the relationship between different power system quantities, such as voltage magnitude and flows in this example.

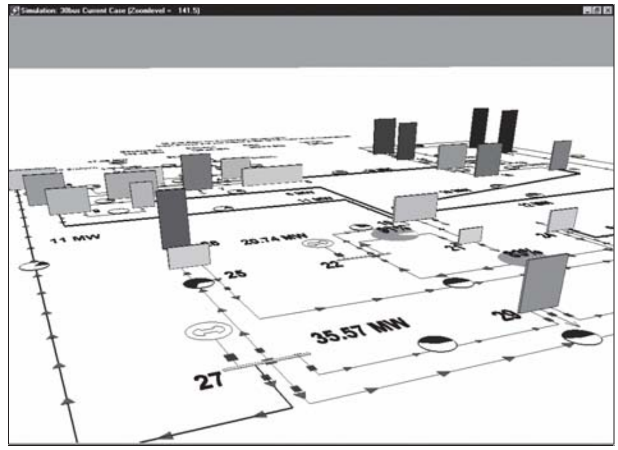

Figure 12: VR View of a 30 Bus System

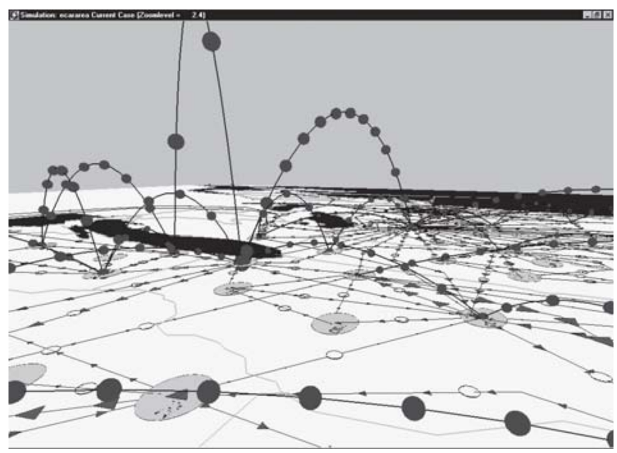

Figure 13: Relationship between Actual Area to Area Flows, and PTDF Values

The potential for VR systems to show relationships between the actual flow of power and the PTDF values is illustrated in Figure 13. This example shows data for the 1998 ECAR case with the PTDF values calculated for a power transfer from Wisconsin to TVA. However rather than showing individual line flow values, only the area to area values are shown. The actual area to area flows are shown in the XY plane, while the PTDF values have been added to the display as trajectory arcs between the different areas. The height of the arc is proportional to the PTDF value, with the movement of the spheres superimposed on the trajectories used to indicate the PTDF direction. For reference, in the figure the observer location is in Northwest Missouri looking towards Lake Michigan.

VR systems can provide an extremely effective method for visualizing power system data. However we conclude this section by noting that they are usually best for describing relationships qualitative relationships between different variables. For exact quantitative results text based displays can be better. Therefore we recommend using the proposed visualization techniques to supplement, but certainly not replace existing techniques.

9. Conclusion

This paper has provided an overview analysis of market power issues involved in analysis of networks including the impact of congestion. Given the importance of the network structure in bulk power markets, the explicit consideration of both the physical and the operation constraints, and the economic aspects of transmission services and generation markets is paramount to correctly assess market power in specific situations. The consideration of market concentration by itself is inadequate, in most cases, for the assessment of market power. As is clear from the various examples, the transmission network plays a pivotal role in the evaluation of potential market power situation. In fact, it is possible for players in various interconnected systems to exercise market power without a dominant position of market concentration.

10. Acknowledgements

The authors would like to acknowledge support of NSF through its grants NSF DMI-9760532 and NSF EEC-9813305.

References

[1] U.S. FERC, Order No. 592, RM96-6-000, Dec., 1996.

[2] U.S. Justice Department & Federal Trade Commission, “Horizontal Merger Guidelines”, April 1992, Revised April 1997, http://www.usdoj.gov/atr/public/guidelines.

[3] U.S. FERC, Notice of Proposed RuleMaking, RM98-4-000, April, 1998.

[4] Staff Report to the U.S. FERC on the Causes of Wholesale Electric Pricing Abnormalities in the Midwest during June 1998, Sept., 1998.

[5] G. Werden, "Identifying market power in electric generation," *Public Utilities Fortnightly*, p. 19, Feb. 15, 1996.

[6] M. Frankena and J. Morris, "Why applicants should use computer simulation models to comply with FERC's new merger policy," *Public Utilities Fortnightly*, pp. 22-26, Feb. 1, 1996.

[7] J.B. Cardell, C.C. Hitt, W.W. Hogan, “Market Power and Strategic Interaction in Electricity Networks, *Resource and Energy Econ.*, vol. 19, 1997, pp. 109-137.

[8] F.M. Scherer, *Industrial Market Structure and Economic Performance*, Rand McNally College Publishing Co., 1980.

[9] Special Issue on Transmission Pricing, *Utilities Policy*, vol. 6, September 1997.

[10] T.J. Overbye, G. Gross, M.J. Laufenberg and P.W. Sauer, "Visualizing Power System Operations in the Restructured Environment," *IEEE Computer Applications in Power*, pp. 53-58, January 1997.

[11] G. L. Landgren, H. L. Terhune, R. K. Angel, "Transmission Interchange Capability - Analysis by Computer," *IEEE Trans. on Power App. and Syst.*, vol. PAS-91, No. 6, Nov/Dec 1972, pp. 2405-2414.

[12] G. L. Landgren, S. W. Anderson, "Simultaneous Power Interchange Capability Analysis," *IEEE Trans. on Power Apparatus and Systems*, vol. PAS-92, No. 6, Nov/Dec 1973, pp. 1973-1986

[13] L. L. Garver, P. R. Van Horne and K. A. Wirgau, "Load Supplying Capability of Generation-Transmission Networks," *IEEE Trans. on Power App. and Syst.*, vol. PAS-98, No. 3, May/June 1979, pp. 957-962.

[14] G. T. Heydt and B. M. Katz, "A Stochastic Model in Simultaneous Interchange Capacity Calculations", *IEEE Transactions on Power Apparatus and Systems*, vol. PAS-94, No. 2, March/April 1975, pp. 350-359.

[15] Union Electric Co., "Simultaneous Transfer Capability: Direction for Software Development", EPRI Report EL-7351, Project 3140-1, EPRI, Palo Alto, CA, August 1991

[16] L.R. Januzik, R.F. Paliza, R.P. Klump, and C.M. Marzinzik, "MAIN Regional ATC Calculation Effect," *Proc. American Power Conf.*, Chicago, IL, April 1997.

[17] F.L. Alvarado, “Market Power: A Dynamic Definition,” Bulk Power Systems Dynamics and Control IV: Restructuring Conf., Santorini, Greece, Aug. 1998.

[18] J.D. Weber, T.J. Overbye, P.W. Sauer, “Simulation of Electricity Markets with Player Bidding,” Bulk Power Systems Dynamics and Control IV: Restructuring Conf., Santorini, Greece, August 1998.

[19] A. Mas-Colell, M.D. Whinston, J.R. Green, *Microeconomic Theory*, Oxford University Press, New York, NY, 1995.

[20] ECAR 1998 Fall Peak (Input, Output, Data Dictionary), http://www.ferc.fed.us/electric/F715.

[21] J.D. Weber, T.J. Overbye, "Power System Visualization through Contour Plots," *Proc. of North American Power Symposium*, Laramie, WY, October 13-14, 1997

[22] T.J. Overbye and J.D. Weber, “Visualization of Large Scale Power Systems,” *Proc. EPSOM ’98*, Zurich, Switzerland, Sept. 1998.

[23] S. Bryson, C. Levit, “The Virtual Windtunnel: An Environment for the Exploration of Three-Dimensional Unsteady Fluid Flows, *IEEE Visualization ’91*, San Diego, CA, 1991.

[24] S. Bryson, “Virtual Reality in Scientific Visualization,” *Computers and Graphics*, vol. 17, pp. 679-685, 1993.

[25] A.O. Veh, et. al., “Design and Operation of a Virtual Reality Operator-Training System, IEEE. Trans. on Power Systems, vol. 11, pp. 1585-1591, Aug. 1996.

[26] E.K. Tam, et. al., “A Low-Cost PC-Oriented Virtual Environment for Operator Training, *Proc. 1997 PICA*, May 1997, pp. 358-364.

[27] www.powerworld.com

[28] M. Woo, J. Neider, T. Davis, OpenGL *Programming Guide, Second Edition*, Addison-Wesley Developers Press, Reading, MA, 1997.