Market Power Evaluation in Power Systems with Congestion

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Abstract

This tutorial paper discusses the assessment 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 such market power..

Keywords: market power, transmission system constraints, congestion, merger analysis, PTDF

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. This restructuring has also been accompanied by an ever growing wave of mergers and acquisitions. 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. Competitive markets are established to deliver benefits unattainable under the regulated market regimes of the past. This drive to competition is being accompanied by the unbundling of services and the disintegration of the vertical structures of the industry. However, this has also given rise to significant concerns that the potential benefits resulting from the breakup of the vertical market power of the traditional utility could, in time, be supplanted by the establishment of horizontal market power. Current regulation seeks to identify potential sources of market power in order to put into place mechanisms to mitigate that power.

In addition to the central role the analysis of market power issues plays in the evaluation of mergers, such analysis is required in:

- corporate unbundling, divestiture, and restructuring proceedings
- approval of market-based wholesale rates
- formation of competitive power pools

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 [4], [5], [6], [18]. Most studies of market power review the structure, conduct, and performance of a market. The structure of a market affects conduct, which in turn impacts performance. Therefore, market power is inherently a problem of structure, and most indicators of market power depend on the structure of the market and the so-called rules of the road. To estimate whether or not an entity will be able to exercise market power, one should focus on whether or not the entity will have that potential given the structure of the market and the associated rules.

For electricity markets, the principal issues of concern are

- the product definition: what are the products traded between buyers and sellers,
- the geographical scope of the markets: where are the buyers and sellers located,
- the market potential versus actual sales.

Given the network structure of power systems, these issues require a thorough understanding and evaluation of the physical and operational constraints to effectively quantify these economic measures.

The product definition in bulk electricity markets must consider time differentiation (on peak vs. off peak vs. shoulder periods), the capacity vs. energy distinction and the role of various existing generating units such as must run as distinct from merit order loading. Moreover, given the regulations in FERC Orders No. 888 and 889, certain ancillary services add to the complexity of the analysis of the markets. The interrelationships between the various markets is a key consideration.

The extent of the geographical market given the FERC promulgation of Orders No. 888 and 889 needs to be carefully examined with the full consideration of the relevant operating and physical/technical transmission network constraints. To define the economic concepts appropriately and to assess and evaluate them correctly, the unique nature of power systems, their operations, control, and planning must be effectively integrated into the analysis. Whenever any of the physical or operational constraints of the transmission network become active, the system is said to be in a state of transmission congestion. The objective of this paper is to provide an overview of the impact that the electrical transmission system has on the analysis market power opportunities, with particular emphasis on the impacts of transmission congestion.

2. Market Power Analysis in Electricity Markets

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

- 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 economically efficient options for storing electric energy.

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 customer, say a load. The size of an electricity market is dependent upon both the physical/operational characteristics of the transmission network used to enable the movement of electricity from the supplier to a buyer, 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) [7], defined as:

$$\mathrm{HHI} = \sum_{i=1}^{N} q_i^2 \tag{1}$$

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. As a simple example, consider a market with four participants, where one participant has a 40% market share, two have 25% each, and the fourth has 10%. The resultant HHI would be $40^2 + 2 * 25^2 + 10^2 = 2950$.

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; mergers increasing the HHI by less than 100 points are considered to be unlikely to have adverse effects. 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. Some of the subtleties of the use of the HHI measure were illustrated in [18].

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 transporta-

[i] We have regrouped the fours steps in [1] into three steps by combining steps 2 and 3 -- geographic markets: identify customers who may be affected by the merger, and geographic markets: identify potential suppliers to each identified customer – into a single step of identifying the relevant geographic market.

tion 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 extent to which any single producer can exercise market power depends then solely on its concentration of ownership relative to that of its competitors, the other producers, in the 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 ownership spread among about 650 different entities. Without any consideration of the transmission network, the associated HHI for the Eastern Interconnect is about 170. Clearly, for this highly simplified conceptual case, completely ignoring consideration of transmission system constraints and transportation charges, no market power exists according to the HHI measure. Mergers between even the largest utilities in the Eastern Interconnect would not substantially affect this value. In contrast, in ERCOT (Electric Reliability Council of Texas), which had a total capacity of about 49.5 GW and about 30 participants, the associated HHI was 2415. Similar values for each of the NERC Reliability Councils are reported in [6]. These values are given here for purely illustrative purposes. In reality, the absence of transmission constraints and charges produces indices that have very limited practical values.

4. Market Power Analysis with Transmission Charges

Of course, neglecting the transmission system and its associated charges provide an unrealistic model of the situation. This is even more pronounced in a large interconnected network. To aid in determining the appropriate geographic market of potential suppliers to a particular customer, FERC requires that the suppliers be able to reach the market both economically and physically. The FERC economic criteria require that a supplier 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 [8]. Whenever there are a number 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 would incur larger transmission charges. The potential for such pancaking is illustrated in Figure 1, which shows several of the operating areas in the Eastern Interconnect along with their interconnections.

The move away from pancaking is a primary 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 single region wide transmission tariff have the desirable impact of potentially enlarging the seller's and/or buyer's market in a given region, effectively lowering the HHI.

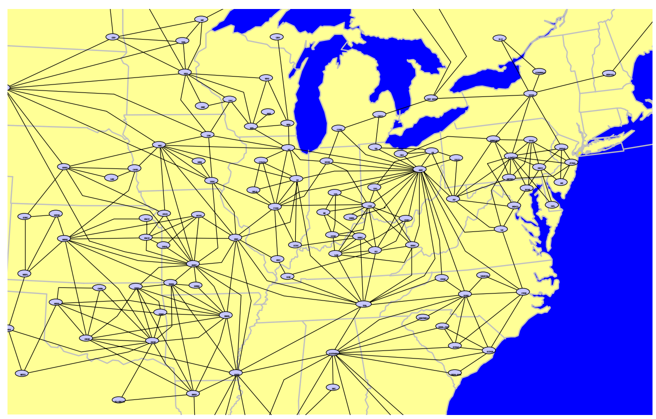

Figure 1: Eastern Interconnect Interconnections

5. Market Power Analysis with Transmission Constraints

Market size may 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 attendant congestion situations. Congestion may arise due to limitations in the "capacity" of the transmission system. The so-called available transfer capability (ATC) is finite but usually not easily determined. The ability of the transmission system to support additional transactions is a function of the network structure, generation and loads. A number of different factors, including transmission line/transformer (line) limits, bus voltage limits, transient stability constraints, and system voltage stability requirements influence the determination of this capacity. 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.

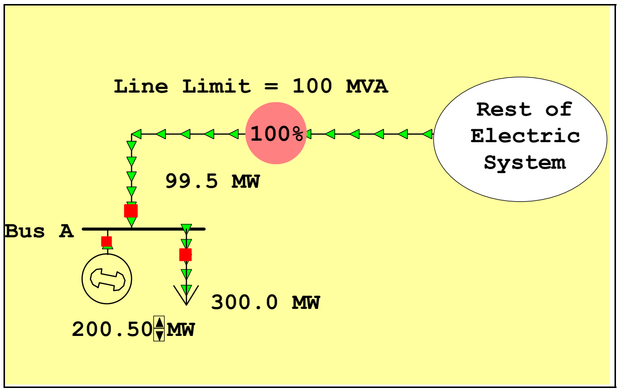

Figure 2: Radial System with Market Power

A very simple case illustrating the impact of the transmission system in market power analysis is the radial single bus network modeled in Figure 2. Here the load at bus A can be served by either local generation at bus A, or generation in the rest of the electric system through the single transmission line joining it to A. 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 [9]. 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. In this situation 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 import capacity limit of the line[ii].

Figure 3 shows the same system as that of Figure 2 except with the addition of a second transmission line joining bus A to the remainder of the system. At first glance one might conclude that analysis of this case only requires a slight extension beyond that of Figure 2. In fact, the situation becomes substantially more complex. Bus A is no longer radially connected to the remainder of the network, but becomes an integral part of the network.

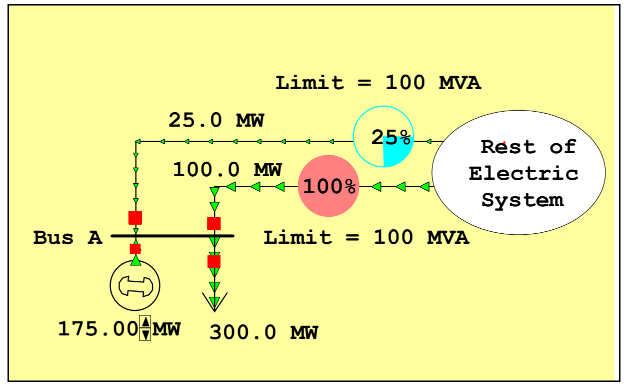

Figure 3: Simple Networked System

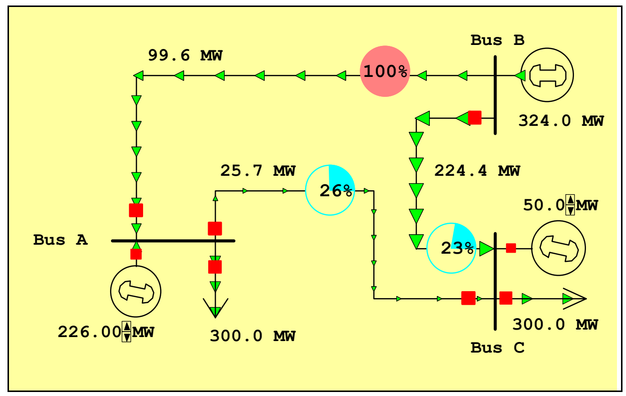

Figure 4: Three Bus Example with Import = 74 MW

A key aspect 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. Such a sum may provide an upper limit in certain cases. The actual import capability 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 two lines reaches its limit or potentially if any other line in the network does. In the Figure 3 case this limit occurs at 125 MW. However, it is quite easy to devise scenarios in which congestion occurs for imports less than the smallest of the individual line limits. Such a situation is illustrated in Figure 4 for a simple three bus system in which 25 MWs is wheeled from bus B to bus C through bus A, decreasing its import capability to about 74 MW. This is below the 100 MVA limit of either line. We have used this simple system to emphasize the importance of network effects. In this case, the ability of bus A to import or export power depends strongly upon conditions in the rest of the network.

We can extend the simple three bus example to more general situations. Consider an area A load pocket to consist of the set of loads, possibly located at multiple buses, that buy power in aggregate using the network.

[ii] Note that this analysis assumes that no other limits are encountered in the rest of the electric system. Also, the impacts of contingencies are not explicitly considered.

Examples of load pockets include a municipality without sufficient internal generation, a cooperative system, or a load aggregator. The degree of market power enjoyed by a set of generators whose operation and control are under a single entity – to be henceforth called a portfolio of generators – in 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 of the network.

In our approach of determining the generation market available to a particular load pocket we use the results provided by the evaluation of the Simultaneous Interchange Capability (SIC) of the network. SIC is a measure of the amount of power that can be imported into a particular load pocket. Determination of SIC involves solving an optimization problem with the objective of selecting 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 [10-14] 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 the power import capability. For the three bus system in Figure 4 the SIC value is 200 MW. This value is attained when bus B generation is 200 MW and bus C generation is 300 MW. However, the SIC result does not solve the market power problem. The principal reason for this is that the assumptions concerning the response of the generators may not hold in a competitive marketplace. All generators need not respond in a way to maximize import into a particular area. While certain 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 a market power opportunity.

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. To aid in this discussion we'll use the common definitions that the set of buses increasing their injection of power into the system will be referred to as the "source", while the set of buses decreasing their injection of power into the system will be referred to as the "sink". The incremental change in power flow then goes from the source to the sink. The source/sink pair is commonly referred to as a "direction". A power transfer from source to sink 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 selection of the source/sink pair, as well as on the characteristics of the transmission network. 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 change as a result of power transfer between the specified source/sink pair.

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 associated with source/sink pairs distant from the congestion. Which directions are limited depends upon whether a transfer would increase or decrease loading on the congested line.

To illustrate these two issues, consider the nine bus network shown in Figure 5. This system has 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. Each transmission line has an impedance of j0.1 per unit with a limit of 200 MVA.

We assume each area controls its interchange and that each load can buy from any of the nine generators. For this case, the SIC value is greater than the load at each bus. 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 there is no market power. The flows resulting are shown in Figure 5; we refer to them as the base case.

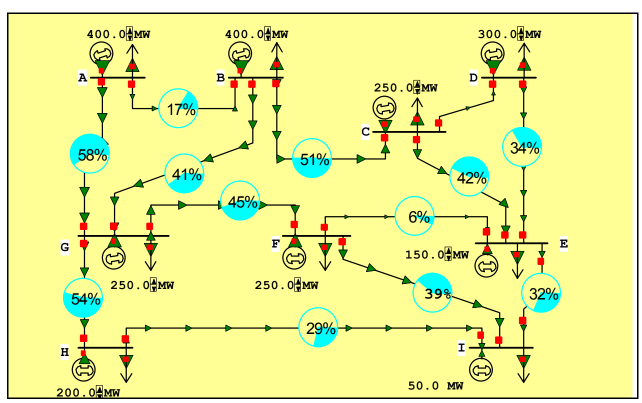

Figure 5: Nine Bus Base Case Flows

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 between a designated source/sink pair. 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 6 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 in the figure now indicate the PTDF values, expressed in terms of a percentage of the power transfer amount. For example, 44% of the transaction flows along the transmission line from bus A to B, while 35% flows from G to F. The expected change in flow along the path is then the PTDF value multiplied by the proposed 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.

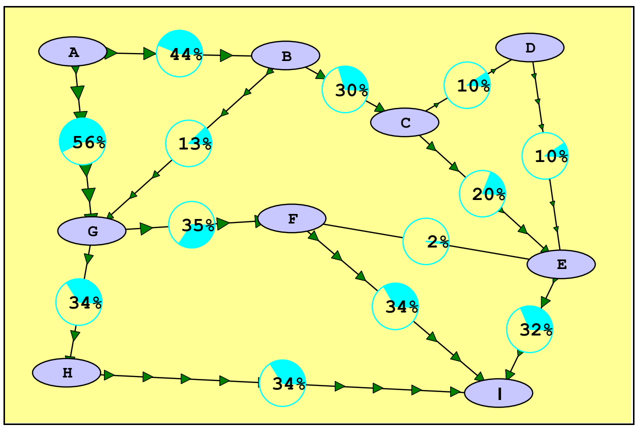

Figure 6: PTDF Values for Transfer from A to I

For a different source/sink pair the PTDF values can be quite different. For example, the PTDF values for a transfer from G to F are shown in Figure 7. Note that the PTDF values for both cases indicate that the transfers would have a significant impact on almost all of the transmission line flows. Present NERC line loading relief criteria deem any transaction having a PTDF value greater than 5% on a limiting element as having a significant impact on the element's line flow.

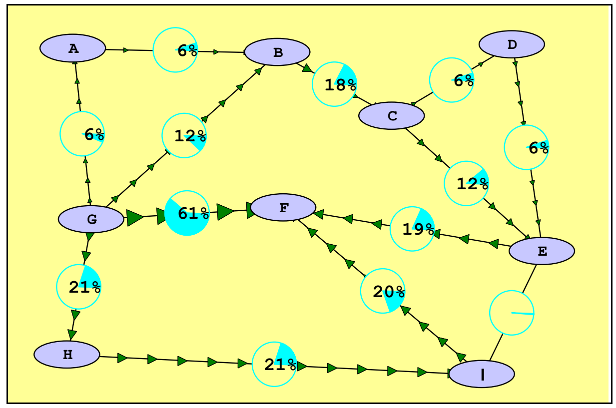

Figure 7: PTDF Values for Transfer from G to F

The PTDF values can also be used to help estimate the maximum amount of power that can be transferred for each direction or source/sink pair [15], [16]. This value is determined by recognizing that for a direction j the real power flow on any line i, P_i, following a power transfer 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_{imax}, 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_{Tjmax} that can be transferred without overloading any line in the set consisting of all lines in the system, Λ, is then

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

With the nine bus case the maximum transfer from A to I is 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 94 MW, with the line from G to F the limiting element.

PTDF impacts constitute important considerations in market power analysis in light of current operating practices. NERC guidelines stipulate that new transfers registering a significant PTDF value (in excess of 5%) on a congested line or interface in the direction that would increase the loading on the congested element cannot be undertaken. For example, for the nine bus system Table 1 shows the PTDF values for the line G-F (with flow from G to F taken as positive) for different suppliers sending power to the I load pocket. Consequently, if congestion were present on the line from G to F, the number of sellers that would have access to the bus I load pocket is significantly decreased. For such a case area I consumers could only buy from areas I, E and F. Therefore, the resultant HHI for area I is 3 * 33.3^2 = 3327, indicating significant market concentration by current standards.

Results from [17] 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 a line is congested. Moreover, this congestion is one-sided. When the direction is reversed the PTDF values simply change sign[iii]. Therefore generators in I can sell to all other areas except for F.

Table 1: Line G to F PTDF Values

Seller to Buyer Direction	PTDF for Line G to F
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%

6. Strategic Behavior

The fact that transmission congestion can limit market size creates the possibility that a portfolio of generators could be dispatched in such a way as to deliberately induce congestion for strategic purposes [18]. For example consider again the Figure 5 nine-bus case. Under the base case assumption of each load being free to select its generation and vice versa, this system has an HHI of 1110, indicating no market concentration. Next consider that areas F and G merge, creating a single entity FG, which now has a 22.2% market share. The remaining seven participants each continue to have an 11.1% share, resulting in a slightly higher HHI of 1355. However, with the portfolio of generators of the combined entity FG there is now increased capability to "manipulate" the flows throughout the network. In particular, the combined entity can redispatch its generation to deliberately induce congestion for strategic purposes.

We first examine the ability of a portfolio of generators to control the flow of power on a particular line. Assume that the portfolio has N generators which are dispatched to meet loads in the network. This portfolio may, in principle, be redispatched in any way desired provided the net change in generation is zero. In particular, the redispatch can be effected to modify the flow on a selected line i. The portfolio redispatch consists of introducing changes ΔP_{gk}, k=1,2,…,N with the constraint that the algebraic sum of these changes is zero. Let S_{ik} be the sensitivity factor of the real flow on line i corresponding to a 1 MW change in the generation at generating bus k. The portfolio may select its redispatch so as to maximize the change in the flow on line i. Then the solution of the problem:

$$\Delta P_i = \max \sum_{k=1}^{N} S_{ik} \Delta P_{gk} \quad \text{s.t.} \quad \sum_{k=1}^{N} \Delta P_{gk} = 0 \qquad (5)$$

provides the redispatch that can impact the flow on line i most severely. This value is maximized by increasing the output of generators with the largest S_{ik} and decreasing those with the smallest values taking into account generation limits.

Let us examine this ability to modify flows in a line in the example system. Consider the merged entity FG and the redispatch of its generation in the two constituent areas. For a change of generation in area F of ΔP_{gF}, a corresponding change of $\Delta P_{gG} = -\Delta P_{gF}$ is made in area G. The entity FG can make the redispatch modification so as to induce congestion on the line between areas G and F. This results in blocking areas A, B, D, and H from serving the area I load. At the same time, the entity FG may continue to sell its generation in area F to serve load in area I. The redispatch resulting from ΔP_{gG} equal to 180 MW leads to a 100% loading of the line from G to F. This is shown in Figure 8.

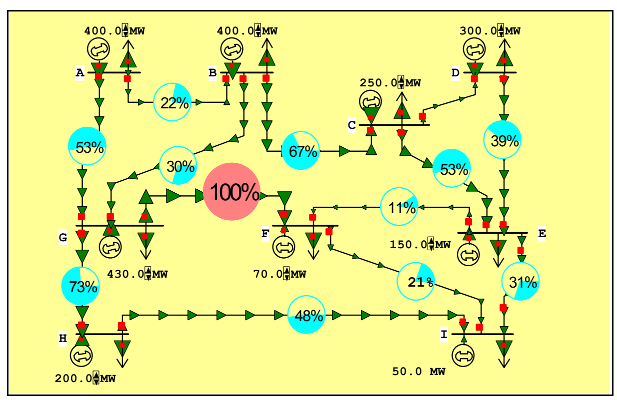

Figure 8: Area FG Blocking Area I Market

The capability to redispatch a portfolio of generators so as to induce congestion in a set of targeted lines, depends upon the *rules of the road* and the structure of the electricity market, in addition to the physical characteristics of the network. Unless specific rules are promulgated, such capability may be used to the detriment of other participants. Clearly, if the entity FG had complete control over its dispatch, it could most easily take advantage of the opportunities of inducing congestion on the transmission line between G and F. However such an opportunity could also be exploited

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[iii] 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).

under much more restrictive conditions. For example, in a bid-based power exchange, entity FG could game its bids in such a way that the generators in areas F and G are selected to serve load and yet still achieve congestion on line G to F, constraining area I. The success of such a strategy would, of course, depend upon expected system loading.

A strategy of deliberately creating congestion could certainly involve additional costs to the "congester". Contributing factors to the cost are how far it must deviate from a purely economic dispatch or bidding strategy. 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 congester would only pursue such a strategy if they had a reasonably good expectation of profit.

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

7. Large System Example

While the previous issues were demonstrated using a small system, they are certainly applicable to practical cases of any size. In this section we'll briefly consider 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 [19]. 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.

As a specific example, Figure 9 shows the interfaces between several of the operating areas, along with the associated PTDF for the area to area interface for a proposed power transfer from Southern Companies to the New York Power Pool. Again pie charts are used to show the loading on each interface, with a larger pie chart used any time the interface loading is over 5%. Note that the power flows spread throughout a large portion of the system. This diffusion is also illustrated in , which uses color contours [20] to show any of the 345 kV and above transmission lines that have PTDF values above 5%. Overall for the Southern to NYPP direction about 280 lines have PTDF values above the 5% threshold. While this is a small fraction of the 41,000 lines modeled in the case, the impacted lines tend to be the high voltage lines that would be used by numerous different transfer directions.

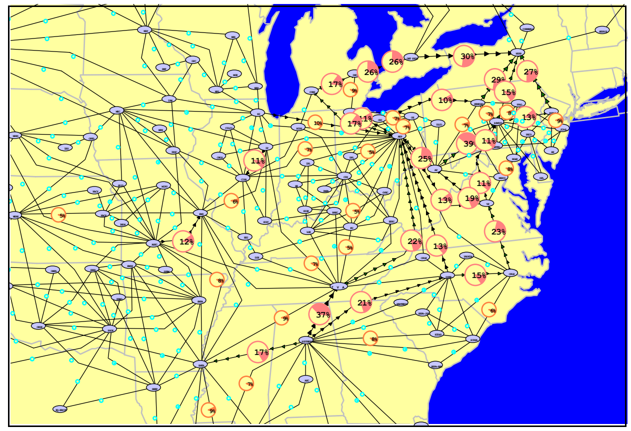

Figure 9: Interface PTDF for Transfer from Southern to NYPP

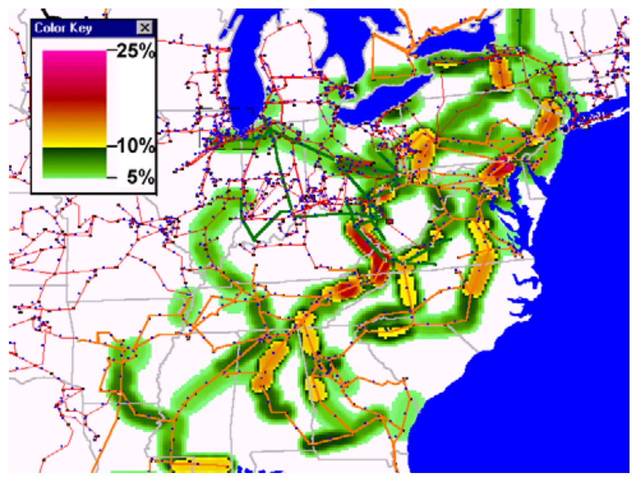

Figure 10: Line PTDFs for Transfer from Southern to NYPP

8. Concluding Remarks

This paper has provided illustrations of market power opportunities in networks and the explicit consideration of the effects of congestion. Given the importance of the network structure in bulk power markets, the explicit consideration of both the physical and the operational constraints, and the economic aspects of transmission services and generation markets is critical to correctly assess market power opportunities in specific situations. The consideration of market concentration by itself is inadequate, in most cases, for the assessment of market power opportunities. 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 interconnected systems to exercise market power without a dominant position of market concentration. The unbundling of electricity services has created a new number of interrelated markets. The interrelationships of these markets, and their impacts on potential market power, will be explored in future papers.

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