Assessment of Transmission Congestion for Major Electricity Markets in the US

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Abstract: This paper details the estimated congestion rent collected by the Independent System Operators (ISO) since their inception in different electricity markets. The electricity markets analyzed are: New York Power Pool, California Power Exchange, and Pennsylvania-Jersey-Maryland (PJM) power pool. The paper describes the significant assumptions underlying the calculations and attempts to delineate the implications of the assumptions. It is observed that the congestion rent calculations are practically accurate for the California Power Exchange since most of the data pertaining to the inter-zonal transmission power flow and the inter-zonal price differential is readily available. On the contrary, the congestion rent estimation for the New York ISO involves significant assumptions. However, it can be shown that the results are reasonably accurate. The efforts for the similar calculations for the congestion rent for PJM electricity power markets proved to be futile. It would not be unfair to comment that when compared to its peer electricity markets, PJM severely lacks transparency in terms of disclosing information pertaining to the transmission congestion rent calculations.

Keywords: Transmission congestion management, congestion rent, merchandising surplus

I. INTRODUCTION

The restructuring process in the electric power industry in the US over the last few years has led to several structural and regulatory issues regarding transmission grid operation and planning not fully anticipated at the design stage of the grid. The transmission system has not evolved at the rate needed to sustain increasing demand matched with negligible generation addition evidenced in the deregulated environment. This has caused somewhat unexpected congestion bottlenecks in the system. Moreover, the functional unbundling of generation and transmission operations is aggravated due to the lack of coordination between the generation resources and the transmission system operator. As the transmission provider takes on a greater role of for-profit company in managing the transmission system, while facilitating the developing energy market, it is increasingly important to project and assess the magnitude of the transmission revenue collected from congestion rent (Presently, the ISOs allocate the congestion rent to the transmission right owners and the excess/shortfall is paid to/collected from the transmission owners [7-9]).

This paper details the estimated congestion rent collected by the Independent System Operators (ISO) since their inception in different electricity markets. The electricity markets analyzed are: New York Power Pool, California Power Exchange, and Pennsylvania-Jersey-Maryland (PJM) power pool. Due to the differences in the congestion management and pricing protocol adopted by the different markets, the computation of congestion rent is a fairly intricate exercise and requires good understanding of the underlying market structure. Similarly, due to the lack of available system and market data, several assumptions are warranted to reduce computational efforts. The paper describes the significant assumptions underlying the calculations and attempts to delineate the implications of the assumptions.

II. BASIC PRINCIPLE FOR CONGESTION RENT CALCULATIONS

The basic principle for the transmission congestion rent could be illustrated with the help of the traditional Spot Pricing theory [2]. In this framework, the central dispatcher optimally dispatches the generators such that the total social welfare is maximized while satisfying the operational and security related constraints. Specifically, the dispatcher solves the following optimization problem.

$$\min_{P_G} \left(\sum_{i=1}^{N_G} C_{G_i}(P_{G_i}) - \sum_{i=1}^{N_D} B_{D_i}(P_{D_i})\right) \quad (1)$$

Subject to:

$$\sum_{i=1}^{N_G} P_{G_i} = \sum_{j=1}^{N} P_{D_j} \quad (2)$$

$$|P_{ij}| < P_{ij}^{\max}$$

$$0 \le P_{G_i} \le P_{G_i}^{\max}$$

$$0 \le P_{D_i} \le P_{D_i}^{\max}$$

where,

$C_{G_i}(P_{G_i})$ = Generation cost curve[1]

$B_{D_i}(P_{D_i})$ = Benefit curve for the demand

P_{G_i} = Power produced by generator I

P_{D_i} = Load at node i

$P_{i,j}$ = Power flow on a transmission line connecting nodes i and j

N = Number of nodes in the transmission network

N_G = Number of Generators

N_D = Number of loads

$P_{G_i}^{max}$ = Maximum generation capacity of generator i

$P_{D_i}^{max}$ = Maximum power consumed by load i

$P_{i,j}^{max}$ =Maximum power flow limit of a transmission line connecting nodes i,j

In most of the energy markets, the load is assumed to be given and not dependent on the price of electricity. For this case, the social welfare function given by Equation (1) becomes total cost of supplying electricity. The demand is typically estimated based on the weather forecast and alike. As the demand becomes more responsive to price, this is likely to change. The study in this paper assumes the typical inelastic demand in the areas for which the calculations are made.

For simplicity, we have used a D.C. power flow in the optimization problem stated above. The first constraint in Equation (1) states that the generation supply must meet the power demand. The second constraint states that the power flow on a transmission line cannot exceed its designed power transfer limit. Finally, the last constraint relates to the generation capacity.

The optimization problem given above can be solved by constructing a Lagrangian as follows.

$$L = \sum_{i=1}^{N_G} C_{G_i}(P_{G_i}) + \lambda\left(\sum_{i=1}^{N_G} P_{G_i} - \sum_{i=1}^{N_D} P_{D_i}\right) + \mu_{i,j}(P_{i,j} - P_{i,j}^{max}) + \eta_{G_i}(P_{G_i} - P_{G_i}^{max}) \quad (3)$$

Taking the partial derivative of the Lagrangian with respect to P_{G_i} and solving further we get,

$$\frac{\partial C_{G_i}(P_{G_i})}{\partial P_{G_i}} + \eta_{G_i} = \lambda + \mu_{i,j}(P_{i,j} - P_{i,j}^{max}) \quad (4)$$

Denoting the spot price at node i as ρ_i, we get

$$\rho_i = \lambda + \mu_{i,j}(P_{i,j} - P_{i,j}^{max}) \quad (5)$$

When there is no congestion $\mu_{i,j} = 0$ and

$$\rho_i = \frac{\partial C_{G_i}(P_{G_i})}{\partial P_{G_i}} + \eta_{G_i} = \lambda \quad (6)$$

$\mu_{i,j} \neq 0$ if $|P_{i,j}| = P_{i,j}^{max}$

As shown in reference [3], the Merchandising Surplus (MS) collected by the ISO is given by

$$MS = -\sum_i \rho_i P_i = \frac{1}{2}\sum_i \sum_j (\rho_j - \rho_i) P_{i,j} \quad (7)$$

Also, at the optimum of Equation (1), the Lagrangian $\mu_{i,j}$ gives the shadow congestion price for the constraint $|P_{i,j}| \le P_{i,j}^{max}$. Therefore, the shadow transmission congestion rent is given by

$$MS = \sum_i \sum_j \mu_{i,j} P_{i,j}^{max} \quad (8)$$

Equations (7) and (8) are used to calculate the transmission congestion rent for the electricity markets under study.

III. CONGESTION RENT CALCULATIONS

A. California Power Exchange

California electricity market uses a zone based congestion management protocol. The entire power system under the control of California ISO is divided into 26 zones. The zones are interconnected by major transmission line groups and are defined as a group of nodes among which transmission congestion is expected to be infrequent and insignificant [1].

The ISO publishes the inter-zonal transmission power flow and price differential (termed as congestion price) on both Day Ahead and Hour Ahead basis at the following web site http://www.caiso.com/surveillance/pricedata/ under the heading Branch Group Prices.

The congestion rent calculation is performed in two stages using Equation (8) for congestion rent calculation described in the earlier section.

1. Day-Ahead (DA) congestion costs are calculated as the product of the congestion price and the line flow connecting the zones.
2. The Hour-Ahead (HA) congestion cost calculation is more involved since the rating of a line/branch group may change between the Day-Ahead and Hour-Ahead markets for several reasons. The congestion cost calculated in stage 1 is then adjusted with the HA congestion charge, which is calculated as follows:
   - If the rating of the lines connecting the zones decreases so that the HA capacity is less than the DA quantity, the incremental difference in the DA and HA quantity is multiplied by the HA congestion charge.

[1] In a typical energy market, the cost and benefit curves are bid-based and do not necessarily reflect the actual cost and/or benefit

- If the rating of the lines connecting the zones increases so that there is more capacity available in the HA market, an amount equal to the difference between the HA and DA quantities multiplied by the HA congestion charge is returned to the scheduling coordinators (or the transmission network users)[2].

The congestion rent for the California electricity market is plotted in Figure 1. The calculations indicate that the California ISO has collected **\$299 Million** over the period April 1998 – Sept. 2000. For the last year (Oct. 99 - Sept. 2000), the congestion rent was **\$222 Million**. It can be easily seen from Table 1 that the congestion rents have risen over the last few months. Also, shown in the figure 2 is the corresponding net line flow on the transmission lines connecting zones at times of congestion.

Since no data exists pertaining to the intra-zonal congestion, it is difficult to estimate the associated costs. Therefore, intra-zonal congestion costs are neglected in the calculations. This is a reasonable assumption, since by definition, intra-zonal congestion is assumed to be infrequent and insignificant [1].

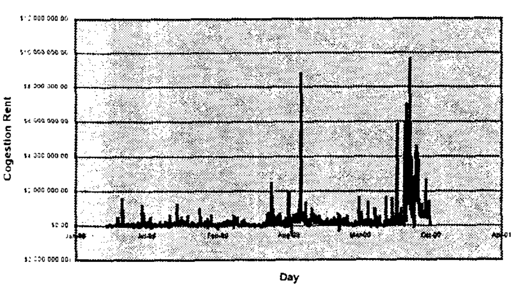

Figure 1: Congestion rent for California Power Exchange (April 1998 – Sept. 2000)

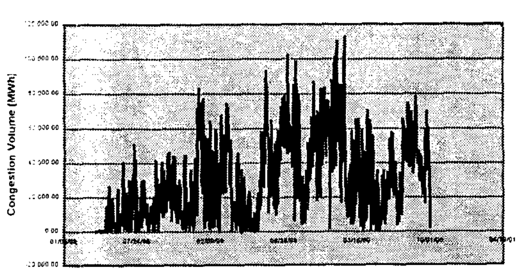

Figure 2: Congestion volume for California Power Exchange (April 1998 – Sept. 2000)

Table 1: Annual Congestion Rent and Volume for California Power Exchange

Year	Congestion Rent (\$ Million)	Congestion Volume (MWh)
April 1998 -Dec. 1998	25	3,513,145
Jan. 1999 – Dec. 1999	87	13,777,000
Jan. 2000 – Sept. 2000	187	10,289,988
Total	**299**	**27,580,133**

B. New York Power Pool

The New York ISO (NY-ISO) has adopted spot pricing-based congestion management protocol. However, unlike the pure nodal price-based spot markets, the ISO has adopted a hybrid nodal-zonal approach for clearing the markets. While a generator is compensated based on the nodal price prevalent at its node, a load is charged on the basis of the average price prevalent in its zone[3]. The ISO has divided the power consumers in New York area in 15 different zones for this purpose. The zonal price, in this case, is the average of the spot prices at each node in the zone.

Based on the congestion management methodology described above, Equation (7) described in the earlier section is used for calculating the congestion rent. The ISO publishes the nodal and zonal prices on a regular basis. Therefore, we need the power injected and withdrawn at each node to accurately estimate the congestion costs for the region. Unfortunately, no data exist for these quantities on the NY-ISO web site. One way to circumvent this problem could have been to get the generation and load patterns at each node as published in the FERC Form 715 power flow cases. However, the NY-ISO provides the market price data on the basis of generation and load PTID (PTID is an identification or index number used in the ORACLE based Database Management System used by the NY-ISO) and there is no mapping available to correlate the PTIDs with the bus numbers used in the form 715 power flow cases. Therefore a few assumptions were warranted.

We assumed that all generators produce power based on their own generation capacity relative to the total generation capacity available. Further, we assumed that the load pattern in each zone would remain the same and would take a value based on the summer peak load case. Finally, we neglected the resistive losses in the system. We gathered information regarding the following quantities:

1. Generation capacity of each generator
2. Load in each zone for the Summer peak load case
3. Historical values of hourly load for the NY-ISO system

[2] This temporal differentiation of congestion costs is likely to change when system users hold long-term transmission rights.

[3] The loads in the other ISO regions such as PJM are treated as individual zones.

Based on these assumptions, the load in each zone for each hour was calculated as

$$Z_{D_i}^{k} = \frac{Z_{D_i}^{peak}}{\sum_{i=1}^{15} Z_{D_i}^{peak}} Q_D^k \qquad (9)$$

for $i = 1,2\ldots15$.
where,
k = Number of hour
i = Number of zone
$Z_{D_i}^{peak}$ = Demand in i^{th} zone as given by the summer peak case
Q_D^k = Total demand at the k^{th} hour

Similarly, the power produced by each generator in each hour is given by

$$Q_{G_i}^{k} = \frac{Q_{G_i}^{\max}}{\sum_{i=1}^{N_G} Q_{G_i}^{\max}} Q_D^k \qquad (10)$$

where,
$Q_{G_i}^{\max}$ = Maximum generation capacity of i^{th} generator
N_G = Total number of generators
$Q_{G_i}^k$ = Power produced by the i^{th} generator in the k^{th} hour

Once the generation at each node and load in each zone is calculated, the congestion cost for the system could be calculated using Equation (7). The congestion cost for the NY-ISO system is plotted in Figure 3 and 4 for Real Time and Day-Ahead dispatch respectively. It is estimated that the NY-ISO has collected **$377 Million** from the market players in terms of the transmission congestion cost over the yearlong period, Nov. 1999 – Nov. 2000[4]. The peak congestion rent is estimated to be $47 Million. It can be observed that the Real Time congestion rent has followed the trend of its Day-Ahead counterpart. The total congestion rent calculated on the Day-Ahead basis is estimated to be **$345 Million** over the period Nov. 1999 – Nov. 2000.

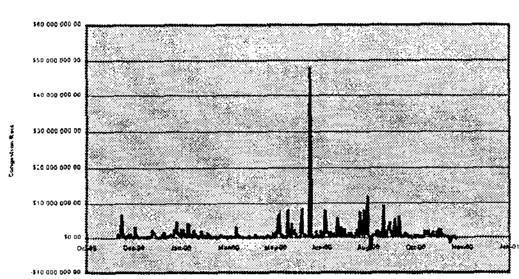

Figure 3: Real time congestion rent for New York Power Pool (Nov. 1999 – Nov. 2000)

[4] The congestion rent calculations for the New York Power Pool are for the period from November 18, 1999 to November 13, 2000.

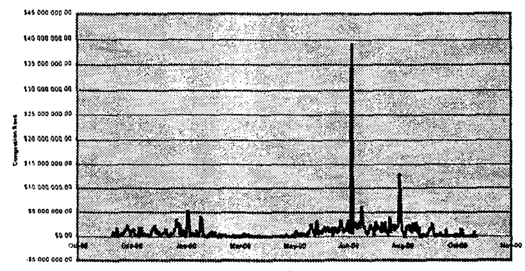

Figure 4: Day Ahead congestion rent for New York Power Pool (Nov. 1999 – Nov. 2000)

Table 2: Congestion Rent for New York Power Pool

	Congestion Rent	Time Period
Real-Time	$377 M	Nov. 99- Nov. 00
Day Ahead	$345 M	Nov.99– Nov. 00

C. PJM Electricity Market

The PJM-ISO follows the Spot Pricing based congestion management protocol similar to the NY-ISO. Both generators and loads are paid or charged based on the Location Based Marginal Price (LBMP). Therefore, the calculations described in the earlier section for the NY-ISO could be easily repeated for the PJM electricity market. As described earlier, the procedure requires the data related to the capacity of the generators and the load demand at each node for a given operating condition within the system. Unfortunately, we found that the PJM electricity market has virtually no information available to make the estimation of the transmission congestion cost possible with reasonable amount of computation efforts (PJM-ISO does publish monthly congestion charges in its news bulletin PJM Highlights [6]. However, there is no information available to replicate the results). As a result, the only way to estimate the congestion costs is to simulate the Optimal Power Flow in a probabilistic manner as described in the publications by MIT-Energy laboratory [4,5]. Given the complexity of the bidding behavior of generating companies, uncertainties in the load demand and equipment outage observed in practice and the computational efforts involved in running the Probabilistic Optimal Power Flow (POPF), we decided that the estimation of congestion cost for the PJM electricity market is not worth pursuing.

PJM-ISO, which prides itself as an "information company" should consider making the information about hourly line power flows publicly available. There is no real harm to be made to anyone by doing so.

IV. CONCLUSION

As different transmission companies in the US have embarked upon providing a for-profit transmission service to the market players for the changing power industry, estimation and projection of the transmission congestion rent has become crucial. The task is complicated due to the difference in the congestion management and pricing protocols adopted by different electricity markets as well as the lack of relevant data posted by the ISOs. The congestion rent calculations for the California and New York electricity markets are summarized in Table 3.

The lack of public information concerning line power flows in the PJM grid has made it difficult to estimate the total transmission congestion costs collected by the PJM-ISO. Accordingly, sophisticated tools such as the Probabilistic Optimal Power Flow (POPF) are needed to accomplish the task. Unfortunately, due to the numerous uncertainties associated with the behavior of the market players and the evolution of the power system topology coupled with the computational efforts severely limit the successful application of the POPF for this purpose.

Finally, the conservatism of the PJM-ISO in disclosing the information pertaining to the line power flows in their grid raises several public policy questions.

Table 3 Summary of congestion rent calculations

Electricity Market	Time Period	Congestion Rent
California PX	April 98 – Sept 00	$299 M
New York Power Pool	Nov 99 – Nov 00	$377 M

V. ACKNOWLEDGEMENTS

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VI. BIOGRAPHIES

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