MIT EL 00-003 WP

Energy Laboratory

Massachusetts Institute
of Technology

Congestion Management for Large Electric Power Systems

May 2000

Congestion Management for Large Electric Power Systems

Yong T. Yoon, Santosh G. Raikar, and Marija D. Ilic

Energy Laboratory Publication # MIT EL 00-003 WP

Energy Laboratory
Massachusetts Institute of Technology
Cambridge, Massachusetts 02139-4307

May 2000

Congestion Management for Large Electric Power Systems

Yong T. Yoon
dreamer@mit.edu

Santosh G. Raikar
sraikar@mit.edu

Marija D. Ilić
ilic@mit.edu

Energy Laboratory

Massachusetts Institute of Technology

Cambridge, MA 02139, USA

Submitted For Publication At *PMAPS'2000, 6th International Conference on Probabilistic Methods Applied to Power Systems*, 2000

Abstract

The sweeping restructuring process in electric power industry has led to more intensive and different usage of transmission grids not foreseen at the design stage. This has resulted in unanticipated congestion interfaces in regional transmission systems. The system is, however, unable to evolve at a rate that is needed to meet the rapidly changing demand of competitive markets. To make the matters worse, the functional unbundling of generation company and system operator will further threaten reliable operation of entire grid due to the lack of coordination between generation and transmission. Thus, a sensible way of dealing with congestion has become vital to maintaining current level of high reliability.

In this paper, we report the results of applying a novel congestion management method recently developed at MIT to a large electric power system. The method allows for market-based solutions with minimal reinforcement provided by system operator for reliability. The majority of reinforcement is in the form of information exchange on zonal pricing of transmission congestion determined ahead of time. Based on this information market participants and system operator can work out attractive trades while avoiding congestion. Stochastic computing tools needed for implementing the method are tested rigorously on New England Electric Power System consisting of approximately 2200 buses and 2800 lines.

I. Introduction

The emerging energy markets take on various forms. Depending on particular regional characteristics some markets admit centralized day-ahead and hour-ahead markets for wholesale trading and a real-time energy market for balancing while others only offer one or two centralized markets, and still others offer only bilateral contracts among market participants with no centralized markets. Most of the markets in various regions within U.S. can be represented by one of three simplified market models: multilateral transaction model, mandatory system operator model and voluntary system operator model [1].

The Multilateral Transaction model is based on bilateral transactions among market participants without the presence of centralized market. In this model, individual buyers and sellers make bilateral trades with one another without disclosing the price and propose the agreed trades to system operator for implementation. The system operator, upon receiving the proposed transactions, makes decisions whether or not to allow the transactions based on analysis of transmission network constraints. Only when the proposed transactions violate transmission limits, the system operator interferes and suggests necessary modifications needed to the transactions through "loading vector" [2]. The market participants make new set of trades to satisfy the remaining demand while observing system limits based on loading vector.

The Mandatory System Operator model is developed based on the practices by traditional regional power pools. In this model a system operator becomes the sole market maker for economically and functionally bundled energy and transmission trades. Initially, market participants bid supply (and demand) curves to the system operator. The system operator then simultaneously dispatches generators and allocates transmission capacity using optimal power flow (OPF) program which determines the most economical mix of generation for given load.

The Voluntary System Operator model supports a multi-tiered structure that minimizes the system operator's influence on profits of market participants while achieving acceptable level of reliability based on pricing signal sent by a system operator. The model makes explicit the separation of markets for trading energy and system operator for allocating transmission capacity. Along with centralized market for energy, bilateral trades are also allowed in this setup.

When there is no congestion, these three market models yield the same optimal equilibrium condition. However, in the presence of congestion, the practical application of methods for relieving congestion allows for very different market equilibria for each model. This is the result of participants' preference to manage their financial risks in real life setting. Some participants opt for entering into bilateral contracts to hedge against price volatility in spot markets while others change their bids to avoid transmission-related risks. This leads to deviations from simple bidding strategy assumed under perfect market condition.[1] Thus, congestion management system (CMS) plays an important role in energy markets as it directly affects the profit of market participants. It should be noted that based on participants' presumed inclination, voluntary system operator model is a preferred market formation over that of mandatory system operator for the existence of explicit bilateral trades and over that of multilateral transaction for the existence of distinct transmission and centralized energy markets. The objective of the paper is to introduce a CMS that is workable in any type of market structure.

The paper is organized as follows:

In Section II, we illustrate the transmission congestion management for the possible market structure with the help of a simple example. Section III describes the tools developed for an efficient CMS. In Section IV we present an application of these tools to the New England Electric Power System. Finally, we conclude with a few recommendations for additional applications of the method.

II. Illustration of CMS for Different Market Structures

The structure of regional energy market shapes the configuration of congestion management system (CMS) for actual implementation. Thus, there are as many different CMS as there are different energy markets. It is noted, however, that these various CMS's can be categorized as either a nodal pricing or a zonal pricing scheme depending on how individual nodes are treated within a system. In nodal pricing, each node takes on different locational price reflecting the effect of transmission congestion. In zonal pricing, the nodes are aggregated into zones along congestion interfaces so that within a zone congestion is infrequent,

[1] This aspect will be explored in more details in the subsequent section.

and congestion costs are assigned on an average basis.[2] In this section we contrast these pricing schemes through an illustration.

Consider a system consisting of four generators and three loads as shown in Figure 1. In

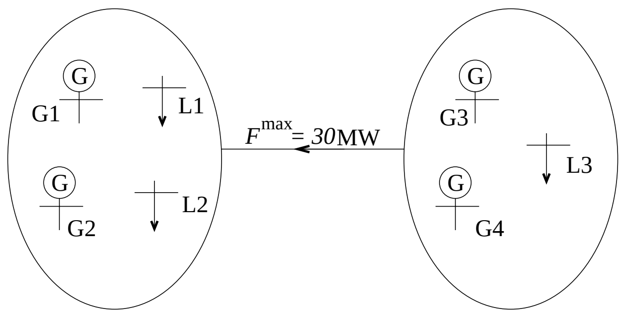

Fig. 1. A Simple Power System Example

this system we assume that all loads are inelastic and identical with demand equal to 50 MW each, $P_{L_i} = 50$. The system condition is such that all transmission lines are operated well within their limits except for one shown explicitly in the figure.

First, we examine the competitive equilibrium under a mandatory system operator model. All generators are required to submit supply bids to a system operator reflecting their respective marginal costs. Figure 2 depicts the supply bids by all generators in the system. Assuming the system is lossless, the system operator decides on dispatch with given supply bids by solving optimal power flow (OPF) for the entire system. OPF solves a static generation cost optimization problem with respect to generator outputs, $P_G^\star = \left[P_{G_1}^\star, \cdots, P_{G_{ng}}^\star,\right]$, for given load demand $P_L = [P_{L_1}, \cdots, P_{L_{nd}},]$. A simplified version[3] of the problem can be expressed as:

$$P_G^\star = \arg\min_{P_{G_i}} \sum_{i=1}^{ng} b_i\left(P_{G_i}\right) \tag{1}$$

subject to load flow constraint

$$\sum_{i=1}^{ng} P_{G_i} = \sum_{i=1}^{nd} P_{L_i} \tag{2}$$

and transmission line constraints

$$|F_l| \le F_l^{max} \tag{3}$$

[2]The definition of zones is consistent with that defined by California Power Exchange. http://www.calpx.com

[3]Sometimes the objective function may include other objectives, e.g. environmental regulation constraints.

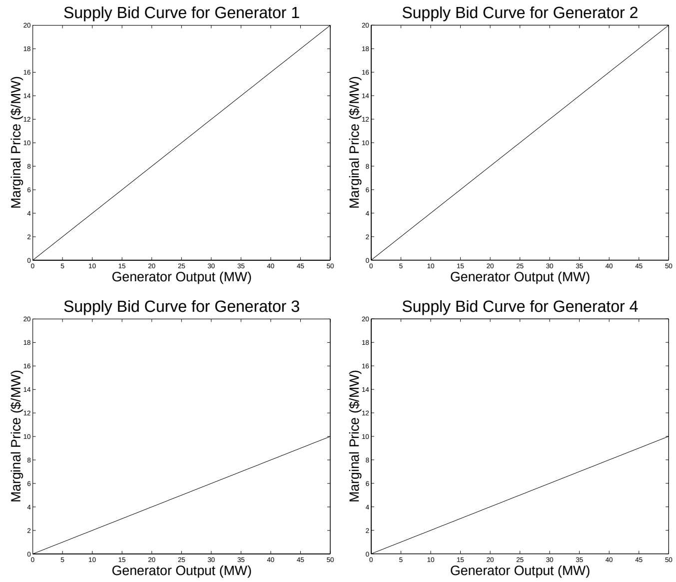

Fig. 2. Supply Bid Curves of Generators

where

P_{G_i}: output of generator i

ng: number of generators in the system

P_{L_i}: demand of load j

nd: number of loads in the system

$b_i(P_{G_i})$: supply bids as a function of P_{G_i}

F_l: power flow on line l for given injection

F_l^{max}: maximum power flow allowed on line l

If there is no transmission congestion, then the nodal price from OPF solution is given at $10/MW at each node. In our example, however, the transmission line shown in Figure 1 has the binding constraint of 30 MW. The resulting OPF solution is summarized in Table II. For given system condition, this OPF solution constitutes the optimal pricing possible [5]. The transmission provider receives the transmission charge of $180 under this pricing scheme.

Suppose some participants, for one reason or another, do not wish to have their output adjusted in the presence of transmission congestion. This requires an existence of separate transmission market. Under this market setup, market participants are expected to submit

	Price ($/MW)	Quantity (MW)	Revenue ($)
Gen 1	14	35	490
Gen 2	14	35	490
Gen 3	8	40	320
Gen 3	8	40	320
Gen Total			1620
Load 1	14	50	700
Load 2	14	50	700
Load 3	8	50	400
Load Total			1800
Trans. Cost	1800 − 1620 = 180 ($)		

TABLE I

MARKET EQUILIBRIUM UNDER MAND. SYSTEM OPERATOR MODEL

separate bids, supply bids for energy market and adjustment bids for transmission market. The participation to both markets is completely voluntary. Some participants will choose only to submit bid into energy market while others will only provide adjustment bids and still others will bid both. First, the energy market is cleared without considering transmission constraints. If there is any transmission limit violation after clearing the energy market, then system operator uses the adjustment bids in most economical way to relieve congestion before accepting bids from the energy market. Under this market structure for our example, we assume the supply bids and adjustment bids shown in Figure 3. From the table it is noted that only generators 1 and 3 are participating in transmission market.

Initially, the energy market clears with price of $10/MW at each node. Since energy market alone cannot satisfy transmission constraints, the system operator uses adjustment bids from the transmission market until the system is within constraints. The resulting financial retribution is summarized in Table II. It is clear from the table that participants are rewarded very differently compared to energy market only structure as each explores different opportunities in this setup. It should be noted that the value of transmission link increases to $360 reflecting reduced participation in transmission market. What is not clear under this nodal pricing scheme is whether generators 2 and 4 are able to easily recognize their respective opportunities in transmission market. They may not have enough information to

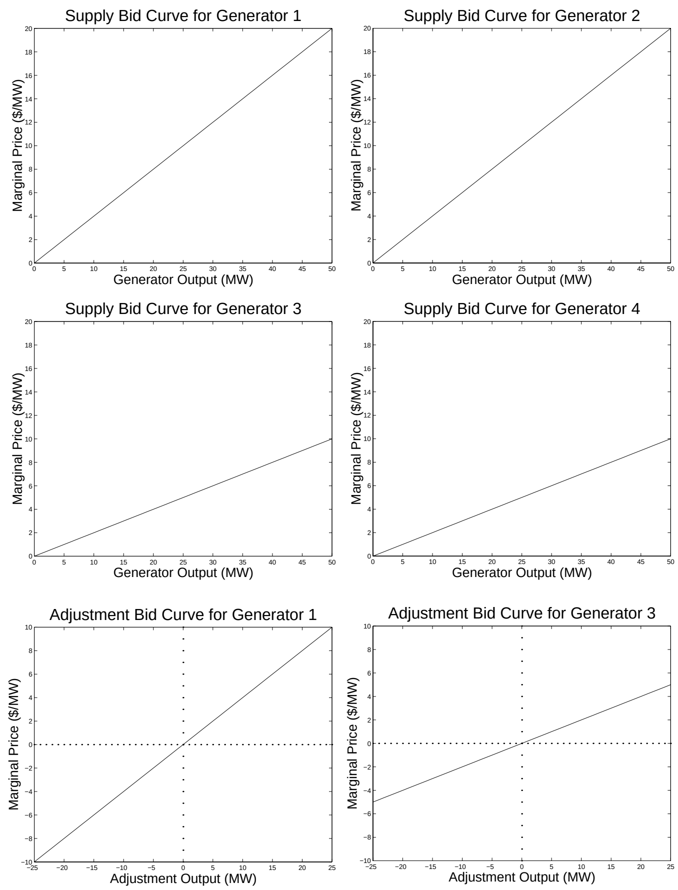

Fig. 3. Supply Bid and Adjustment Bid Curves by Generators

	Price ($/MW)	Quantity (MW)	Revenue ($)
Gen 1	18	45	810
Gen 2	10	25	250
Gen 3	6	30	180
Gen 4	10	50	500
Gen Total			1740
Load 1	18	50	900
Load 2	18	50	900
Load 3	6	50	300
Load Total			2100
Trans. Cost	$2100 - 1740 = 360$ ($)		

TABLE II

Market Equilibrium under Separate Transmission Market identify the binding transmission congestion and thus, may not know their very different prospects in transmission market given the same nodal price. Thus, it may be more sensible to employ a more transparent zonal pricing scheme. For example, once generators 1 and 2 are declared to be in the same zone reflecting their similar effect on congested transmission lines, generator 2 will easily recognize its opportunity in transmission market based on nodal price of generator 1. The similar is true for generator 4. Suppose, generators 2 and 4 decide to submit adjustment bids same as those of generators 1 and 3 respectively to exploit the opportunities in transmission market, the market equilibrium moves to that of a mandatory system operator model. Therefore, it is clear that the boundaries of zones must be drawn along congestion interfaces *based on technical criteria* and not by simply aggregating nodes with similar nodal prices.

Suppose the market structure now admits explicit bilateral contracts among participants. As described in the previous section, the presence of bilateral contract is auspicious particularly if the spot market exhibits high price volatility. Suppose, in our example, load 2 seeks bilateral contracts to fulfill its demand of 50MW. The congestion charges for bilateral contract have been pre-defined by system operator at 0 ($/MW) for transactions between generator 1 or 2 and load 2 and at c_{tr} ($/MW) for transactions between generator 3 or 4 and load 2.

All generators in the system, first, compete for bilateral contracts with load 2 after evaluating contract strike prices with respect to modified energy supply curve shown in Figure 4. The intercepts, b_1, b_2, b_3, and b_4, reflect proportionally the expectation of spot prices of each generator. We allow dynamic modifications of these intercepts based on the result of

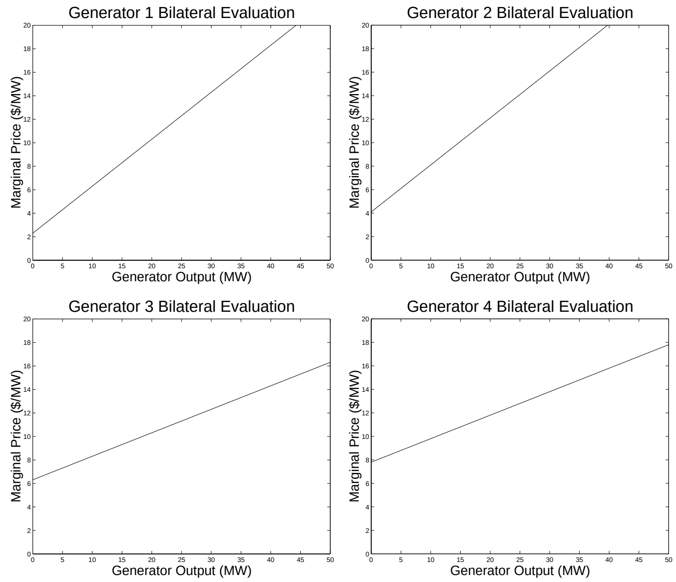

Fig. 4. Bilateral Contract Evaluation Curves of Generators

spot prices according to the following expression:

$$\begin{aligned} b_1[i] &= b_1[i-1] + \tfrac{p_{G_1}[i-1] - p_{bilater}[i-1]}{r_1} \\ b_2[i] &= b_2[i-1] + \tfrac{p_{G_2}[i-1] - p_{bilater}[i-1]}{r_2} \\ b_3[i] &= b_3[i-1] + \tfrac{p_{G_3}[i-1] - (p_{bilater}[i-1] - c_{tr})}{r_3} \\ b_4[i] &= b_4[i-1] + \tfrac{p_{G_4}[i-1] - (p_{bilater}[i-1] - c_{tr})}{r_4} \end{aligned} \tag{4}$$

where

p_{G_i}: clearing price at node i after adjustment for transmission congestion

$p_{bilater}$: strike price for bilateral contracts

c_{tr}: congestion charge

r_i: rate at which generator i adjusts the intercept of its bilateral strike price evaluation curve

i: number of times bilateral transactions and market clearing processes take place

After entering into bilateral contracts generators then submit their energy and adjustment bids to markets as in Figure 3 except generators 2 and 4 are also participating in transmission market through submitting adjustment bids same as those of generators 1 and 3.

Table III shows market equilibria after allowing iterative convergence through several stages, i until the intercepts do not change at $c_{tr} = 4$, 6 and 8 (\$/MW). In this formulation zonal pricing scheme is implied. It is interesting to note that while markets clear at the optimal clearing price defined in mandatory system operator model, a strike price for bilateral contract deviates if the transmission charge assigned by system operator for bilateral contract does not accurately agree with the value of transmission defined in markets. Therefore, it is important that system operator has the ability to establish *congestion charges ex ante with high degree of certainty based on expected usage* of the transmission system.

As illustrated through a simple example, there is a strong need for tools in assessing the value of transmission and in aggregating nodes into zones in meaningful way based on technical criteria,[4] as the system operating condition changes. In the next section we describe such tools recently developed at MIT.

III. Tools for CMS

Solving OPF described in the previous section yields the most economical generation mix for a given time instance from existing system condition. Although the solution is useful in suggesting the desirable operating point at each moment in time, it is not directly applicable for assessing the value of transmission as the operating condition changes. In [6] probabilistic optimal power flow (POPF) is introduced to evaluate the likely use of transmission system. Using this novel method binding transmission limits can be identified under normal operating conditions with probability. The value of transmission is deduced based on the result of solving POPF. In this section we describe briefly a POPF formulation.

POPF uses a Monte Carlo-based method to efficiently solve optimal power flow taking into

[4]We refer to zones defined strictly based on technical criteria as (congestion) clusters to avoid any confusion.

c_{tr} = 4 ($/MW), Strike Price = 12 ($/MW)

	Price ($/MW)	Market Sale (MW)	Bilateral Sale (MW)	Revenue ($)
Gen 1	14	35	0	490
Gen 2	14	35	0	490
Gen 3	8	15	25	320
Gen 4	8	15	25	320
Gen Total				1620
Load 1	14	50	0	700
Load 2	12	0	50	600
Load 3	8	50	0	400
Load Total				1700

c_{tr} = 6 ($/MW), Strike Price = 14 ($/MW)

	Price ($/MW)	Market Sale (MW)	Bilateral Sale (MW)	Revenue ($)
Gen 1	14	16	19	490
Gen 2	14	16	19	490
Gen 3	8	34	6	320
Gen 4	8	34	6	320
Gen Total				1620
Load 1	14	50	0	700
Load 2	14	0	50	700
Load 3	8	50	0	400
Load Total				1800

c_{tr} = 4 ($/MW), Strike Price = 14 ($/MW)

	Price ($/MW)	Market Sale (MW)	Bilateral Sale (MW)	Revenue ($)
Gen 1	14	14	25	490
Gen 2	14	14	25	490
Gen 3	8	40	0	320
Gen 4	8	40	0	320
Gen Total				1620
Load 1	14	50	0	700
Load 2	14	0	50	700
Load 3	8	50	0	400
Load Total				1800

TABLE III

Market Equilibrium under Voluntary System Operator Model account transmission line flow limits and generation capacity constraints over the possible range of load demand. First, we construct probability density function of system demand. Traditional utilities have published what is referred to as, load duration curve, that depicts the cumulative probability of system load as shown in Figure 5. The probability density

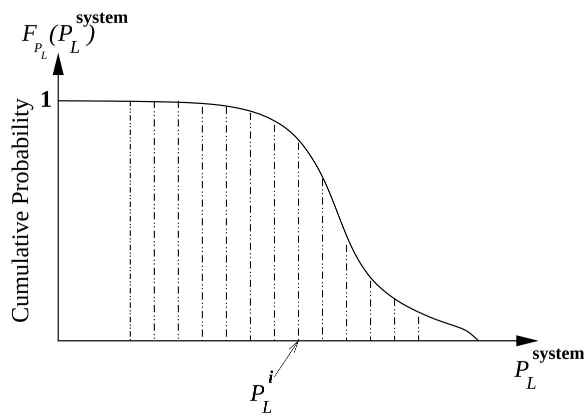

Fig. 5. Discretized Load Duration Curve

function of system load, f_{P_L} is computed then by taking the first derivative of load duration curve as follows:

$$f_{P_L}(P_L^i) = \left(\frac{dF_{P_L}}{dP_L}\right)_{P_L=P_L^i} \tag{5}$$

Given the probability density function, individual load pattern is computed along the incremental increase in system load starting from its minimum. Because of metering problem, the probabilistic modeling of individual load pattern may not be easily inferable in real-life systems. In [7] an approach is suggested to cope with this problem. The approach finds the peak, off-peak and normal individual load patterns and their corresponding range of system load as shown in Figure 6. Employing fuzzy logic, these patterns are meshed to create

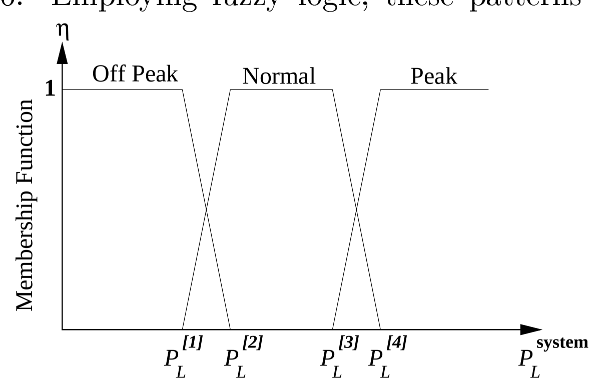

Fig. 6. Membership Functions for Individual Load Pattern

typical individual load pattern that matches the probability density function of system load as follows, $P_L^{[k]} = P_L^{\text{system}}(k)$:

$$P_L^{[k]} = \left(\eta^{[N]} \frac{P_l^{[N]}}{1^T P_L^{[N]}} + \eta^{[OP]} \frac{P_l^{[OP]}}{1^T P_L^{[OP]}} + \eta^{[PK]} \frac{P_l^{[PK]}}{1^T P_L^{[PK]}} \right) \tag{6}$$

Finally, OPF is solved as in Eq. (1) using individual load patterns along the system load from the minimum to the maximum. Computing flows on transmission lines after OPF and fitting the flows against probability density function yield cumulative probability of transmission system usage.

$$\begin{aligned} \text{Prob}\left\{ F_l \leq \bar{F}_l \right\} &= \text{Prob}\left\{ F_l\left(P_G^{\star}(P_L^i)\right) \leq \bar{F}_l \right\} \\ &= \int_0^{\bar{F}_l} f_{P_L}(P_L^i) dF_l \end{aligned} \tag{7}$$

This result is then used to derive the value of transmission.

As it is demonstrated in previous section, zonal pricing to transmission congestion management is more useful for a voluntary system operator model. Here we briefly describe the result of [8] that allows aggregation of nodes based on technical criteria.

Given system and transmission lines suspect of binding constraints, congestion distribution factors (CDF) are computed to identify the group of system users who have similar effects on the transmission lines. This grouping is referred to as zonal aggregation into congestion clusters. The clusters are arranged in a hierarchy and enumerated as of type 1, 2 , $\cdots$, n. The congestion cluster of type 1 represents the users with the most impact on constrained transmission line. The impact is non-uniform for this cluster. Starting from cluster 2, the impact is uniform and becomes smaller with increase in numbers for cluster type. Based on this grouping, all bilateral transactions can be evaluated to charge for transmission. For example, transactions across cluster boundaries have greater impact on congestion and are charged high for transmission usage. Transactions within a cluster are charged with low transmission cost except for transactions within cluster 1. Due to high and non-uniform CDFs, transactions within cluster 1 have to be charged high for their large impacts.

CDFs are derived from distribution factors. First, distribution factors in usual sense are computed twice with respect to two different slack bus locations within the same system for transmission line of interest, i.e. $\left\{ D_m^{(i,j)} \right\}$ and $\left\{ D_n^{(i,j)} \right\}$ where bus n is used as the slack bus for the first computation, and bus m is for the second. Then, the difference between these two sets of distribution factors, $\beta_{m,n}^{(i,j)}$, is the result of having two slack buses in different location. Defining the difference as

$$\beta_{m,n}^{(i,j)}\{1\} = \left\{D_m^{(i,j)}\right\} - \left\{D_n^{(i,j)}\right\} \tag{8}$$

where $\{1\}$ is the vector of all ones, $\beta_{m,n}^{(i,j)}$, can be expressed as [8]

$$\beta_{m,n}^{(i,j)} = D_m^{(i,j)}(n) = -D_n^{(i,j)}(m) \tag{9}$$

where $D_m^{(i,j)}(n)$ denotes the nth element of the vector $\left\{D_m^{(i,j)}\right\}$.

Define the shift vector, ϕ as

$$\phi^{i,j} = -\frac{D_m^{(i,j)}(i) + D_m^{(i,j)}(j)}{2} \tag{10}$$

for given distribution factors, $\left\{D_m^{(i,j)}\right\}$ with respect to the slack bus, m. Then, we can subtract out the locational effect of slack bus from distribution factors by adding the sum of shift vector elements to the given distribution factors. The resulting vectors are what is defined as CDF, $\left\{D^{(i,j)}\right\}$:

$$\left\{D^{(i,j)}\right\} = \left\{D_m^{(i,j)}\right\} + \phi^{(i,j)}\{1\} \tag{11}$$

The magnitude of resulting CDF defines the sensitivity of the flow in transmission line of interest on a transaction; this formulation ensures that sensitivity of flows on the line of interest with respect to a bus injection decreases monotonically as the electrical distance between the line and the bus increases. The sign denotes if the transaction will increase or relieve the congestion.

By using POPF and CDF, the value of transmission can be accurately estimated. The following section describes one practical application of these methods.

IV. Example

The New England Power System comprises of approximately 2200 buses and 2800 lines. The system carries the summer peak load of 20,500 MW and the winter peak load of 18,000 MW.

Figure 7 depicts the load duration curve for New England system constructed from yearly system load data available from the Federal Energy Regulatory Commission[5]. As described

[5]http://www.ferc.fed.us

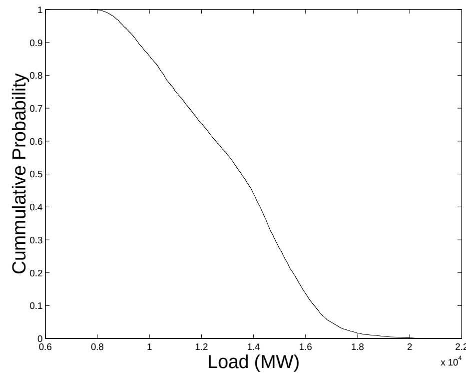

Fig. 7. Load Duration Curve of New England System

in the previous section, we compute the probability density function for system load by differentiating load duration curve. Next, some approximations are made for reducing computational complexity. Instead of solving OPF continuously over the range of possible system load, computation is done in discrete steps of 100 MW. This entails deducing probability distribution function in increments of 100 MW from the probability density function. The resulting probability for the simulation purposes is given in Figure 8. For each simulation

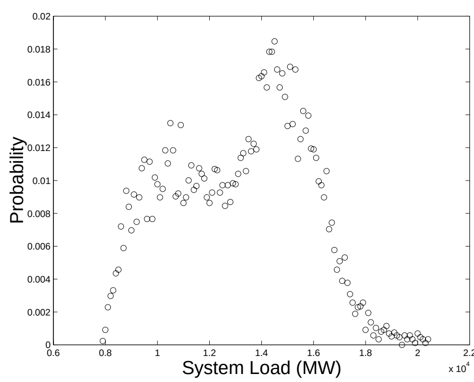

Fig. 8. Probability Distribution Function of Discretized System Load for New England

step, corresponding individual load pattern is derived using the summer peak load case data.

The cost function for each generator, $b_i(P_{G_i})$ is prepared based on its marginal cost of generation. All marginal costs are calculated based on the fuel cost (C_{fuel}), Heat Rate (R_{heat}), and O&M costs ($C_{\text{O\&M}}$). For simplicity, the marginal costs of generation are treated constant for the generation output range available $b_i(P_{G_i}) = b_i$.

$$b_i = C_{\text{fuel}} \cdot R_{\text{heat}} + C_{\text{O\&M}} \tag{12}$$

With constant marginal cost and DC load flow approximation, the computational complexity of the problem becomes reduced sufficiently for guaranteeing the convergence of OPF in Eq. (1). Simple linear programming algorithm is used for optimization.

The result of solving POPF on New England system is summarized in Table IV regarding the lines most likely to be congested and their corresponding probabilities. As an example,

From	To	Prob$\{\lvert F_l \rvert \approx F_l^{max}\}$
Harris	Harris #2	0.025
Harris	Harris #3	0.025
Winslow 115	Winslow 34.5	0.1
J/Mill D	Int. Paper	1.0
Champ	UCKSPOR	0.8
J/Mill C	Otis	0.78
Reactor	S. Hero	0.08
Grand IS	S. Hero	0.12
Grand I	PLAT T#3	0.125
Essex	IBM K24	0.15
Middlesex	Berlin	0.05
Middlesex	IBM K24	0.02
BARRE	Granite	0.925
BARRE	Berlin	0.005
Prospect	Alewife	0.05
Mashpee 23	Mashpee 115	0.0005
Water 115	Water 13.8	0.005
Norwel S9	Norwel	0.005
Litchfield 115	Litchfield 13.8	0.0005
Read 115	Read 13.2	0.0005

TABLE IV

TRANSMISSION LINES MOST LIKELY TO GET CONGESTED UNDER NORMAL OPERATION

Figure 9 shows the cumulative probability of flows on the (uncongested) transmission line between "Canal" station and "Canal G1" station. It is interesting to note that the lines listed in the table are restricted in a small geographical area in the Northwest part of the system. This is a consequence of the weak system support in that part of the system. Other than those lines, the transmission lines in New England are utilized well within their

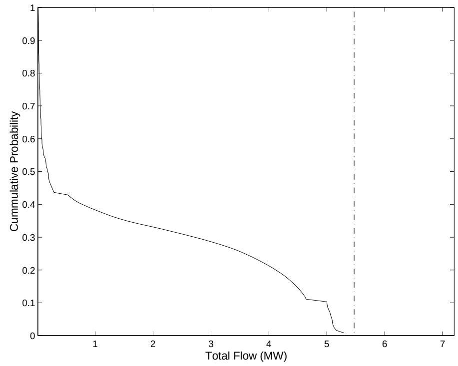

Fig. 9. Cumulative Probability of Flow on Line Between Canal Station and Canal G1 Station Under Normal Operating Conditions

operating constraints under normal operating conditions. This result agrees with the analysis performed by New England power pool [9].

We summarize the result of computing CDFs for likely congested lines under normal operating conditions for defining clusters in Table V.

Suppose we extend the analysis to include the probability of transmission outages in assessing system usage. Table VI shows the result of solving POPF on New England system with the transmission line between "Sherman" station and "Card" station out. Figure 10 shows the cumulative probability of flows on (now congested) transmission line between "Canal" station and "Canal G" station. For completeness we summarize the result of solving CDF

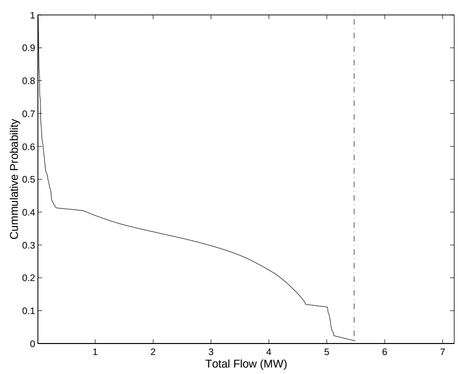

Fig. 10. Cumulative Probability of Flow on Line Between Canal Station and Canal G Station under A Simple Contingency

for the likely congested lines under a simple contingency in Table VII. Finally, we describe the method of combining results in Tables IV and VI for simple contingencies.

From	To	Min. CDF	Max CDF
Harris	Harris #2	-0.5000	0.5000
Harris	Harris #3	-0.5000	0.5000
Winslow 34.5	Winslow 115	-0.2020	0.2020
J/Mill D	Int. Paper	-0.2470	0.2470
Champ	UCKSPOR	-0.5000	0.5000
J/Mill C	Otis	-0.4477	0.4477
Reactor	S. Hero	-0.4836	0.4836
Grand IS	S. Hero	-0.4489	0.4489
Grand I	PLAT T#3	-0.4942	0.4942
Essex	IBM K24	-0.4726	0.4726
Middlesex	Berlin	-0.3581	0.3581
Middlesex	IBM K24	-0.4679	0.4679
BARRE	Granite	-0.4687	0.4687
BARRE	Berlin	-0.2709	0.2709
Prospect	Alewife	-0.5000	0.5000
Mashpee 23	Mashpee 115	-0.5000	0.5000
Water 115	Water 13.8	-0.5000	0.5000
Norwel S9	Norwel	-0.5000	0.5000
Litchfield 115	Litchfield 13.8	-0.5000	0.5000
Read 115	Read 13.2	-0.5000	0.5000

TABLE V

CDFs under Normal Operating Conditions

Using

$$\begin{aligned}\text{Prob}_{F_l}(\bar{F}_l) = \ & (1 - \text{Prob}(C))\text{Prob}_{F_l}(\bar{F}_l|\tilde{C}) \\ & + \text{Prob}(C)\text{Prob}_{F_l}(\bar{F}_l|C)\end{aligned} \tag{13}$$

where C: contingency and $\tilde{C}$: no contingency, we can compute the cumulative probability of flows on each line to account for possible occurrence of a contingency. Figure 11 shows the result on transmission line between "Canal" station and "Canal G" station given $\text{Prob}(C) = 10\%$. In order to account for probability of more than one simultaneous contingencies, however, a more efficient computing method is needed since the above approach leads to 2^{n_c} combinatorial search, where n_c is the number of contingencies to consider.

From	To	Prob$\{|F_l| \approx F_l^{max}\}$
Harris	Harris #2	0.04
Harris	Harris #3	0.04
Winslow 34.5	Winslow 115	0.12
J/Mill D	Int. Paper	1.0
Champ	BUCKSPOR	0.825
J/Mill C	Otis	0.75
Reactor	S. Hero	0.08
Grand IS	S. Hero	0.1
Grand I	PLAT T#3	0.1
Essex	IBM K24	0.15
Middlesex	Berlin	0.1
Middlesex	IBM K24	0.02
BARRE	Granite	0.925
BARRE	Berlin	0.005
Prospect	Alewife	0.05
Canal	Canal G1	0.005
Mashpee 23	Mashpee 115	0.0005
Water 115	Water 13.8	0.05
Norwel S9	Norwel	0.05
Moore CO3	Moore G2	0.02
Moore CO3	Moore G4	0.02
Litchfield 115	Litchfield 13.8	0.0005
Read 115	Read 13.2	0.0005
Deerfield	Harriman	0.0005
Vernon	Deerfield #4	0.0005
Berkpower	South Agawam	0.001

TABLE VI

Transmission lines most likely to get congested under a simple contingency conditions

From	To	Min. CDF	Max CDF
Harris	Harris #2	-0.5000	0.5000
Harris	Harris #3	-0.5000	0.5000
Winslow 34.5	Winslow 115	-0.2020	0.2020
J/Mill D	Int. Paper	-0.2470	0.2470
Champ	BUCKSPOR	-0.5000	0.5000
J/Mill C	Otis	-0.5000	0.5000
Reactor	S. Hero	-0.4478	0.4478
Grand IS	S. Hero	-0.4837	0.4837
Grand I	PLAT T#3	-0.4491	0.4491
Essex	IBM K24	-0.4942	0.4942
Middlesex	Berlin	-0.4727	0.4727
Middlesex	IBM K24	-0.3585	0.3585
BARRE	Granite	-0.4680	0.4680
BARRE	Berlin	-0.4688	0.4688
Prospect	Alewife	-0.2709	0.2709
Canal	Canal G1	-0.5000	0.5000
Mashpee 23	Mashpee 115	-0.5000	0.5000
Water 115	Water 13.8	-0.5000	0.5000
Norwel S9	Norwel	-0.5000	0.5000
Moore CO3	Moore G2	-0.5000	0.5000
Moore CO3	Moore G4	-0.5000	0.5000
Litchfield 115	Litchfield 13.8	-0.5000	0.5000
Read 115	Read 13.2	-0.5000	0.5000
Deerfield	Harriman	-0.4096	0.4096
Vernon	Deerfield #4	-0.2048	0.2048
Berkpower	South Agawam	-0.5000	0.5000

TABLE VII

CDFs under a Simple Contingency Conditions

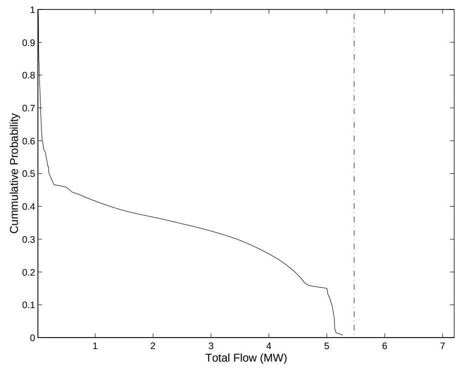

Fig. 11. Combined Cumulative Probability of Flow on Line Between Canal Station and Canal G Station

V. Conclusion

The need for an effective congestion management system (CMS) has been well recognized as the energy market becomes more demanding. In this paper we have demonstrated that a practical application of CMS leads to different market equilibrium conditions under different market structures. Different equilibrium conditions mean different profit dividend to each market participant. Thus, for any CMS to be successful, it must be fair and transparent. This calls for the market-based solutions. We have reported the result of applying the newly developed tools, probabilistic optimal power flow (POPF) and congestion distribution factors (CDFs) computation techniques, to a real-life system. These tools support a novel CMS that relies on the least reinforcement provided by a system operator necessary for reliability. By applying these tools transmission providers can make accurate assessment of transmission system usage and can communicate to system users the effects of individual transactions on the physical grid. The chief advantage of CMS introduced here is its workabililty in any type of market structure including the preferred voluntary system operator model which has the flexibility to allow bilateral contracts among participants while keeping separate markets for energy and transmission. Finally, we have given directions to further developing the method to include system contingency analysis.

Acknowledgments

The authors greatly appreciate the financial support provided by the MIT Energy Laboratory Consortium for "New Concepts and Software for Competitive Power Systems", making this study possible.

References

[1] Léotard, J-P., Ilić, M., "On the Objectives of Transmission Pricing under Open Access", *IEEE Power Engineering Society Winter Meeting*, Vol. 1, pp. 476-483, New York, NY, 1999.

[2] Wu, F., Varaiya, P., "Coordinated Multilateral Trades for Electric Power Networks: theory and implementation", *International Journal of Electrical Power & Energy Systems*, vol.21, no.2, U.K., Feb., 1999, pp.75-102.

[3] Hogan, W., "Contract Networks for Electric Power Transmission", *Journal of Regulatory Economics*, Vol. 4, No. 3, September 1992, pp. 211-242.

[4] Ilić, M., "Network-theoretic Conditions for Existence and Uniqueness of Steady State Solutions to Electric Power Circuits", *Proc. ISCAS'92*, pp.2821-2828, San Diego, CA, 1992.

[5] Schweppe, F., et al., *Spot Pricing of Electricity*, Kluwer Academic, Boston, MA, 1987.

[6] Descamps, F., Feltin, L., "A New Model to Assess the Composite Adequacy and the Operating Costs of Large Interconnected Power Systems", *Proceedings of the Powertech Conference*, Stochdem, Sweden, 1995.

[7] Yu, C-N, "Hierarchical Congestion Management for A Deregulated Power Industry", MIT Ph.D. Thesis, Dept. of Mechanical Engineering, September, 1999.

[8] Yu, C-N, Ilić, M., "Congestion Clusters-Based Markets for Transmission Management", *Proceedings of the IEEE PES Winter Meeting*, New York, NY, 1999.

[9] New England Power Pool, "Monitoring of Potential Constrained Areas for Congestion Pricing Purposes", May, 1997.