Transmission Management in the Deregulated Environment

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Invited Paper

Three very different methods of accomplishing the same task—managing the operation of the transmission system in the deregulated power system operating environment—have been implemented as deregulated market structures have been created around the world. They are first, the optimal power flow (OPF) model found in various implementations in the United Kingdom, parts of the United States, and in Australia and New Zealand. Second, the point tariff, price area congestion control model used in the Nordpool market area in Norway and Sweden. Third, the U.S. transaction-based model. All are pragmatic solutions implemented in advance of complete theoretical understanding. Each has strengths and flaws, and there are some surprising inter-relationships. Each maintains power system security but differs in its impact on the economics of the energy market. No clearly superior method has so far emerged. In the future, methods of combining decentralized market solutions with operational use of optimal power flow may provide better solutions to existing and emerging problems.

Keywords*—Congestion, deregulation, optimal power flow, price areas, transmission access, transmission management, transmission management system (TMS).*

I. Introduction

In 1988 almost all electric power utilities throughout the world operated with an organizational model in which one controlling authority—the utility—operated the generation, transmission, and distribution systems located in a fixed geographic area. Economists for some time had questioned whether this monopoly organization was efficient. With the example of the economic benefits to society resulting from the deregulation of other industries such as telecommunications and airlines, and in a political climate friendly to the notion of deregulation, the United Kingdom was the first to restructure its nationally owned power system, creating privately owned companies to compete with each other to sell electric energy. Deregulation followed in Norway, Australia, and New Zealand, and then, in the 1992 National Energy Policy Act (NEPA), in the United States.

The form of the deregulated electric power industry differs in each country and among various regions in the United States. Three main forms can be identified, although details vary widely among specific implementations. The forms are the optimal power flow model used in the United Kingdom, Australia, New Zealand, and some parts of the United States (although this classification of the U.K. implementation is disputable), the price area based model used in Norway, Sweden, and Finland, and the transaction based model used in the United States. These models deal in very different ways with the interaction between the properties and limitations of the transmission system and the economic efficiency of the energy market.

How do these models interact with the transmission system? Why are there such large differences in these implementations when the basic goal of delivering electric energy bought and sold in a competitive market is the same? Prior to deregulation, utility operating practices were far more uniform throughout the world. Which of these implementations is better? How are they interrelated? Subsequent sections address these questions from the specific point of view of transmission management.

First, the transmission management problem under deregulation will be defined in general terms, identifying the issues that must be addressed by any deregulated structure. Next, an example power system will be introduced, with a discussion of the calculation of transmission power flow. Then the three existing forms of deregulated structure will be described. It is not possible within the scope of this paper to give detailed descriptions of specific implementations, but basic mechanisms that address transmission management issues are il-

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lustrated with simple examples. More detailed information can be found in [11]–[37].

Next, the strengths and flaws of each implementation are discussed, and interrelationships among the implementations are examined. Finally, an attempt is made to identify the work that can be done to enhance the understanding of transmission management in the deregulated environment.

II. The Transmission Management Problem

The arguments made for deregulation can be found in any undergraduate microeconomics textbook, and are as applicable to an industry of factories producing generic "widgets" as they are to an industry of generators producing electric energy measured in MWh. In the first approximation, there is little difference between widgets and MWh, and the economic principles and techniques applied to one can be, have been, and are being applied to the other. In the second approximation, however, electric energy has some characteristics that require special attention. These include the inability to store energy in electrical form in any significant amounts, large daily and seasonal variation in demand, operational requirements for power system control and reliability, and perhaps most importantly, network externalities, the properties and limitations of the transmission system that transports electric energy from the generators that produce it to the loads that consume it.

A. Power Flow on Transmission Networks

Economics has dealt in detail with transportation networks. However, these networks generally assume a free choice among alternate paths between source and destination nodes and implicitly assume that goods can be stored when they cannot be moved. The transmission system does not in general exhibit these properties. Electric energy cannot be stored. Given a set of source and destination power entry and removal sites, the ability to control which transmission paths the electric power takes is extremely limited. The physics of the power system, governed by Kirchhoff's Voltage Law, dictate how much of the energy being moved from one node to another travels over each of the links in the system. While power system apparatus like phase shifting transformers or high voltage power electronics (a family of equipment known as flexible ac transmission systems, or FACTS) can control the power flow over an individual link, such equipment is presently expensive and rare.

Better flow control would be useful because every link in the transmission system has a limit on the amount of power it can transfer at a given time. Several phenomena can impose these transfer limits, including thermal limits, voltage limits, and stability limits, with the most restrictive, of course, applying at any given time. Limits must be set to encompass both normal operation and the possibility of the unplanned disconnection of links or generators, called outages or contingencies, so that the power system can continue to deliver power when such contingencies occur.

Ensuring that the power system operates within its limits has traditionally been referred to as power system security. The term reliability has come into more common use after deregulation. Maintaining security and reliability is vital. Failures can result in widespread blackouts with potentially severe social and economic consequences.

B. Congestion Management

When the producers and consumers of electric energy desire to produce and consume in amounts that would cause the transmission system to operate at or beyond one or more transfer limits, the system is said to be congested. Congestion management, that is, controlling the transmission system so that transfer limits are observed, is perhaps the fundamental transmission management problem.

Congestion is a term that has come to power systems from economics in conjunction with deregulation, although congestion was present on power systems before deregulation. Then it was discussed in terms of steady-state security, and the basic objective was to control generator output so that the system remained secure (no limits were violated) at the lowest cost. When dealing with power flow within its operating area, one entity, the vertically integrated utility, controlled both generation and transmission, gained economically from lower generation costs, and was responsible for the consequences and expected costs when less secure operation resulted in power outages. Conflicts between security and economics could be traded off within one decision-making entity. While this process sounds quite exact, the expected costs of less secure operation could not be accurately quantified, and the limits themselves could develop a great deal of flexibility when there was money to be saved by pushing them.

In the prederegulation power system, most energy sales were between adjacent utilities. The transaction would not go forward unless each utility agreed that it was in their best interests for both economy and security. Only when the transaction had an impact on the security of an uninvolved utility, a situation known as third-party wheeling, did problems that would now be called congestion arise. In the Eastern United States, these problems eventually led to the general agreement on parallel paths (GAPP) [1]. This agreement basically provided an approximate method for computing the effect of a transaction on third parties, and a set of rules spelling out when the third party could intervene to limit a transaction because of their security concerns. The transmission management system (TMS) discussed in Section VI is a descendent of GAPP.

In the deregulated power system, the challenge of congestion management for the transmission system operator is to create a set of rules that ensure sufficient control over producers and consumers (generators and loads) to maintain an acceptable level of power system security and reliability in both the short term (real-time operations) and the long term (transmission and generation construction) while maximizing market efficiency. The rules must be robust, because there will be many aggressive entities seeking to exploit congestion to create market power and increased profits for themselves at the expense of market efficiency. The rules should also be fair in how they affect different participants, and they should be transparent, that is, it should be clear to all participants why a particular outcome has occurred. The form of congestion management is dependent on the form of the energy market, and congestion management itself cannot be separated from market considerations.

C. Market Economics and Congestion

The performance of a market is measured by its social welfare. Social welfare is a combination of the cost of the energy and the benefit of the energy to society as measured by society's willingness to pay for it. If the demand for energy is assumed to be independent of price, that is, if demand has zero price elasticity, then the social welfare is simply the negative of the total amount of money paid for energy. It can be shown [2] that a perfect market has maximum social welfare. Real markets always operate at lower levels of social welfare. The difference in social welfare between a perfect market and a real market is a measure of the efficiency of the real market.

The conditions required for perfect competition are:

1) there are a large number of generators, each producing the same product;
2) each generator attempts to maximize its profits;
3) each generator is a price taker—it cannot change the market price by changing its bid;
4) market prices are known to all generators;
5) transmissions are costless.

Arguably none of these conditions ever exists in a real market.

When a generator is a price taker, it can be shown that maximizing its profit requires bidding its incremental costs. When a generator bids other than its incremental costs, in an effort to exploit imperfections in the market to increase profits, its behavior is called strategic bidding. If the generator can successfully increase its profits by strategic bidding or by any means other than lowering its costs, it is said to have market power. The obvious example of market power is a nonregulated monopoly with a zero elasticity demand, where the generator can ask whatever price it wants for electric energy. Market power results in market inefficiency.

There are many possible causes of market power, among them congestion. Consider a simple example of a two zone system connected by an interface, shown in Fig. 1. Let each zone have a 100-MW constant load. Zone A has a 200 MW generator with an incremental cost of \$10/MWh. Zone B has a 200 MW generator with an incremental cost of \$20/MWh. Assume both generators bid their incremental costs.

If there is no transfer limit between zones, all 200 MW of load will be bought from generator A at \$10/MWh, at a cost of \$2000/h, as shown in Fig. 1(a). If there is a 50 MW transfer limit, then 150 MW will be bought from A at \$10/MWh and the remaining 50 MWh must be bought from generator B at \$20/MWh, a total cost of \$2500/h. Congestion has created a market inefficiency of 25% of the optimal costs, even without strategic behavior by the generators.

Congestion has also created unlimited market power for generator B. B can increase its bid as much as it wants, because the loads must still buy 50 MW from it. Generator B's market power would be limited if there was an additional generator in zone B with a higher incremental cost, or if the loads had nonzero price elasticity and reduced their energy purchase as prices increased. In the real power system, cases of both limited and unlimited market power due to congestion can occur. Unlimited market power is probably not socially tolerable.

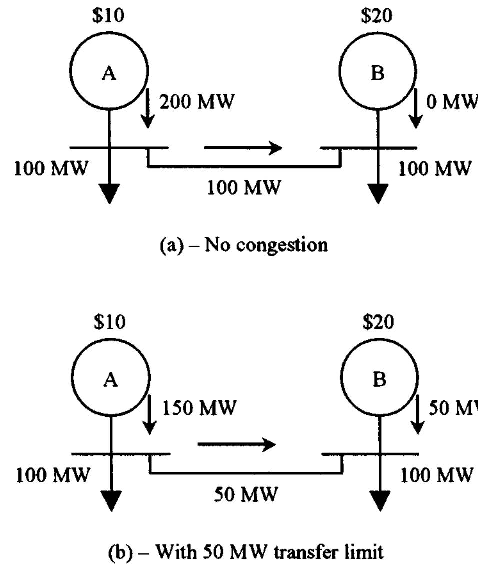

Fig. 1. Two zone system.

The creation of market inefficiency due to congestion in an otherwise perfect market is not a bad thing, as the cost of market inefficiency can be traded off against the cost of improving the transmission system and thus serves as an economic signal for transmission reinforcement. Even the creation of limited market power can be viewed in this framework. However, unlimited market power, and market power arising from factors other than congestion or the number of generators in a congested zone, such as loopholes in market rules, exploitation of technical parameters, or conflict of interest (such as if generator B were permitted to schedule maintenance outages of the interface), does not provide useful economic signals.

D. Transmission Management Issues

There are three main issues in transmission management: congestion; transmission tariffs; and transmission losses.

Three forms of congestion management have arisen in the course of deregulation around the world. One form is based on centralized optimization, either explicitly with some form of optimal power flow program, or implicitly, depending on system operators to control congestion. A second form is based on the use of price signals derived from *ex ante* market resolution to deter congestion by allowing congestion to constrain scheduled generator output prior to real time operation. Inevitably some congestion may still arise and must be corrected in real time by centralized control. A third form seeks to control congestion by allowing or disallowing bilateral transmission, agreements between a producer and a consumer, based on the effect of the transaction on the transmission system. Each approach will be discussed in more detail later.

Congestion is also central to the issue of transmission tariffs, that is, how much is paid, and by whom, for the use of the transmission system. There are three aspects to the tariff issue in transmission management. The first is to ensure that there is sufficient revenue to cover the costs of the transmission system operators and the transmission system owners (who may not be the same). While covering operating costs is generally not a problem, the revenue stream must also motivate efficient transmission construction, a problem that is not as easily solved. The second aspect of transmission tariffs is that they can be used in various ways to manage congestion. They can send real time or *ex ante* price signals to transmission system users to control congestion operationally, and they can send long term price signals to motivate siting of new generators or major loads. The final aspect of transmission tariffs is that they can be used to bias the decentralized, unconstrained optimization process in the energy market to account for the physical phenomenon of transmission losses.

Losses are the last, but not the least, concern in transmission management. While they may be included in tariffing, they can also be treated separately, and a variety of approaches to loss management have appeared. Although loss effects may appear small compared to other potential sources of market inefficiency, they should certainly be handled as efficiently as possible.

Congestion management remains the central issue in transmission management in deregulated power systems. Without firm control of congestion, the operation of the transmission system can be compromised by the actions of market participants who do not have an economic stake in its security and reliability. Without careful attention to the interaction of congestion management and the economics of the energy market, market inefficiencies can take away the savings deregulation promises to society. The next three sections examine three different solutions to the transmission management problem produced by the interaction of power engineering and economics.

III. Example Power System and Power Flow Analysis

A. Example Power System

To illustrate the operation of different congestion management systems, an example power system is used. The example is an eleven zone power system shown in Fig. 2. Each zone is a collection of electrical buses connected well enough so that overloads on transmission lines and transformers within the zone can be neglected. Thus, each zone can be treated as a single bus in power flow computation. Zones are connected by interfaces. Each interface consists of multiple identical transmission lines, also called circuits. Power flow limits (ratings) in MW for the interfaces are given in Table 1. The rating of each interface is simply the rating of each circuit in the interface times the number of circuits in the interface.

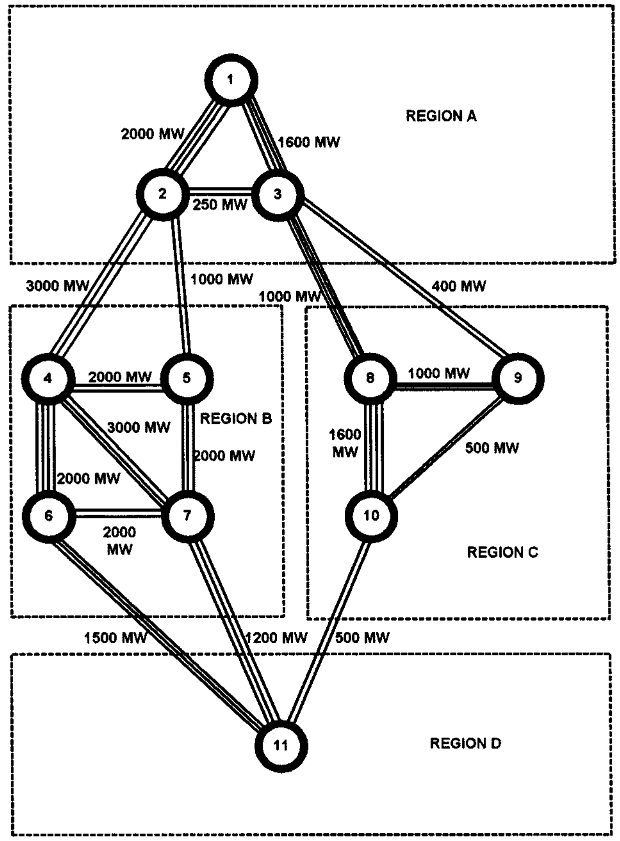

Fig. 2. Eleven-zone model.

Table 1
Example Transmission System Data

Interface	From Zone	To Zone	No. of Circuits	Circuit Reactance X, per unit	Capacity in MW
1	1	2	4	0.020	2000.0
2	1	3	4	0.025	1600.0
3	2	3	2	0.080	250.0
4	2	4	3	0.010	3000.0
5	2	5	2	0.020	1000.0
6	3	8	4	0.040	1000.0
7	3	9	2	0.050	400.0
8	4	5	2	0.010	2000.0
9	4	6	4	0.020	2000.0
10	4	7	3	0.010	3000.0
11	5	7	3	0.015	2000.0
12	6	7	2	0.010	2000.0
13	8	10	4	0.025	1600.0
14	8	9	3	0.030	1000.0
15	9	10	2	0.040	500.0
16	6	11	3	0.020	1500.0
17	7	11	3	0.025	1200.0
18	10	11	2	0.040	500.0

Individual circuits can be lost, or outaged, one at a time. The event where a circuit is lost is called a contingency. When a contingency occurs, the power flow increases in the remaining circuits in the interface (although the total flow on the interface will decrease) and on circuits in other interfaces. Flow limits immediately following a contingency are usually higher than in normal operation. Operators are expected to be able to reduce flows to normal limits before circuit damage occurs. To reflect this common practice, post-contingency interface limits are 10% higher than normal interface flow limits.

B. DC Power Flow

Calculating the power flows that result in a power system from a given set of loads and generator power outputs is an analytical technique central to transmission management. A full ac power flow [3] is the most accurate calculation, but its complexity can obscure relationships. Throughout this paper, a dc power flow model is used.

The dc power flow model assumes that only the angles of the complex bus voltages vary, and that the variation is small. Voltage magnitudes are assumed to be constant. Transmission lines are assumed to have no resistance, and therefore no losses. These assumptions create a model that is a reasonable first approximation for the real power system, which is only slightly nonlinear in normal steady state operation. The model has advantages for speed of computation, and also has some useful properties.

1) *Linearity:* If the MW in a transaction from one zone to another is doubled, the flows that are directly attributable to this transaction will also double.
2) *Superposition:* The flows on the interfaces can be broken down into a sum of components each directly attributable to a transaction on the system.

With the assumptions listed above, the power flow on a transmission line connecting bus i to bus j, P_{ij}, is given by

$$P_{ij} = \frac{1}{x_{ij}}(\theta_i - \theta_j) \tag{III.1}$$

where

x_{ij} line inductive reactance in per unit;
θ_i phase angle at bus i;
θ_j phase angle at bus j.

The total power flowing into bus i, P_i, is the algebraic sum of generation and load at the bus and is called a bus power injection. It must equal the sum of the power flowing away from the bus on transmission lines, so

$$P_i = \sum_j P_{ij} = \sum_j \frac{1}{x_{ij}}(\theta_i - \theta_j). \tag{III.2}$$

This can be expressed as a matrix equation

$$\begin{bmatrix} P_1 \\ \vdots \\ P_n \end{bmatrix} = \begin{bmatrix} & & \\ & \mathbf{B_x} & \\ & & \end{bmatrix} \begin{bmatrix} \theta_1 \\ \vdots \\ \theta_n \end{bmatrix} \tag{III.3}$$

where the elements of the susceptance matrix $\mathbf{B_x}$ are functions of the line reactances x_{ij}. The $\mathbf{B_x}$ matrix is singular, but by declaring one of the buses to have a phase angle of zero and eliminating its row and column from $\mathbf{B_x}$ the reactance matrix $\mathbf{X}$ can be obtained by inversion. The resulting equation then gives the bus phase angles as a function of the bus injections

$$\begin{bmatrix} \theta_1 \\ \vdots \\ \theta_{n-1} \end{bmatrix} = \begin{bmatrix} & & \\ & \mathbf{X} & \\ & & \end{bmatrix} \begin{bmatrix} P_1 \\ \vdots \\ P_{n-1} \end{bmatrix} \tag{III.4}$$

where the injection at the zero phase angle bus is simply the negative sum of all other bus injections in the system.

A full dc power flow then proceeds as follows.

Step 1: Evaluate the bus injections P_i at each bus i as the algebraic sum of all generation into the bus minus the sum of all loads on the bus.

Step 2: Multiply the vector of bus injections $\mathbf{P}$ by the reactance matrix $\mathbf{X}$ for the network to get the vector of bus phase angles θ.

Step 3: Find the line power flow P_{ij} from (III.1) using the line reactances x_{ij} and the bus phase angles θ_i found in step 2.

Step 4: The line flow values P_{ij} are compared to the line's MW limit and any overloads noted.

The line reactances for the example power system are given in Table 1. The solution for a 1000 MW transaction from zone 1 to zone 11 (with all other injections zero) is shown in Fig. 3.

C. Power Transfer Distribution Factors (PTDF's)

From the power flow point of view, a transaction is a specific amount of power that is injected into the system at one zone by a generator and removed at another zone by a load. The linearity property of the dc power flow model can be used to find the transaction amount that would give rise to a specific power flow, such as an interface limit. The coefficient of the linear relationship between the amount of a transaction and the flow on a line is called the PTDF. PTDF is also called a sensitivity because it relates the amount of one change—transaction amount—to another change—line power flow.

The PTDF is the fraction of the amount of a transaction from one zone to another that flows over a given transmission line. $\text{PTDF}_{ij,\,mn}$ is the fraction of a transaction from zone m to zone n that flows over a transmission line connecting zone i and zone j. The equation for the PTDF is

$$\text{PTDF}_{ij,\,mn} = \frac{X_{im} - X_{jm} - X_{in} + X_{jn}}{x_{ij}} \tag{III.5}$$

where

x_{ij} reactance of the transmission line connecting zone i and zone j;
X_{im} entry in the ith row and the mth column of the bus reactance matrix $\mathbf{X}$.

The change in line flow associated with a new transaction is then

$$\Delta P_{ij}^{\text{New}} = \text{PTDF}_{ij,\,mn} \cdot P_{mn}^{\text{New}} \tag{III.6}$$

where

i and j buses at the ends of the line being monitored;

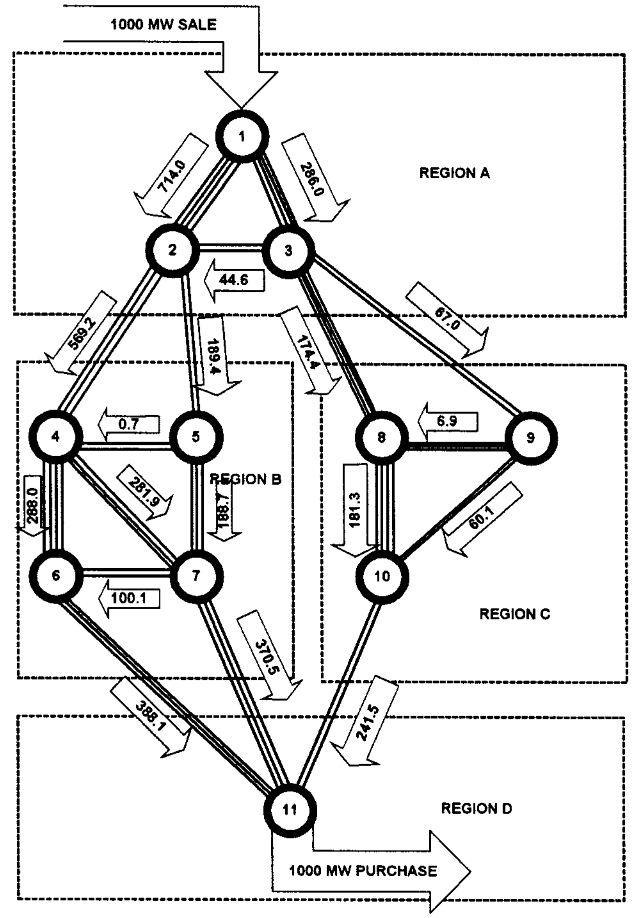

Fig. 3. 1000-MW transaction from zone 1 to zone 11.

m and n — "from" and "to" zone numbers for the proposed new transaction;

P_{mn}^{New} — new transaction MW amount.

If the transaction amount was 100 MW and the PTDF was 0.6, then 60 MW would flow on the line connecting bus i and bus j.

The PTDF's for a transaction from zone 1 to zone 11 in the example power system are given in Table 2.

Interface PTDF's are found by summing the PTDF's for all of the circuits in service on that interface. The PTDF's can be used to calculate the effect any transaction from zone 1 to zone 11 will have on any interface. For example, for a 1000-MW transaction from zone 1 to zone 11, $1000 \cdot 0.714 = 714$ MW of the transaction will appear on the interface from zone 1 to zone 2. If power were already flowing on the interface from zone 1 to zone 2, 714 MW would be added to that flow. If the transaction is from zone 11 to zone 1 the PTDF's are simply negated.

D. Contingency Effects and the Line Outage Distribution Factor (LODF)

In addition to observing the transfer limits that exist with all lines in service [called the $n-0$ case by the North American Electric Reliability Council (NERC)], the transmission system must also stay within limits in the event of unplanned outages of transmission lines or transformers. Testing the power system for overloads when a single circuit is out is called the $n-1$ test. Generally the power system is operated so that the $n-0$ and $n-1$ tests can be passed at all times and some critical $n-2$ tests (two circuits out) can be met as well. In this paper, only the $n-1$ test is applied.

Table 2
Transaction PTDF's

Monitored Interface	Transaction From - To 1 to 11
1 to 2	0.7140
1 to 3	0.2860
2 to 3	-0.0446
2 to 4	0.5692
2 to 5	0.1894
3 to 8	0.1744
3 to 9	0.0670
4 to 5	-0.0007
4 to 6	0.2880
4 to 7	0.2819
5 to 7	0.1887
6 to 7	-0.1001
8 to 10	0.1813
8 to 9	-0.0069
9 to 10	0.0601
6 to 11	0.3881
7 to 11	0.3705
10 to 11	0.2415

The dc power flow could be used to calculate the effects of each line outage, but linear sensitivities can speed computation. When an outage occurs, the power flowing over the outaged line is redistributed onto the remaining lines in the system. The LODF is the measure of this redistribution. $\text{LODF}_{ij,rs}$ is the fraction of the power flowing on the line from zone r to zone s before it is outaged, which now flows over a line from zone i to zone j

$$\Delta P_{ij,rs} = \text{LODF}_{ij,rs} \cdot P_{rs} \tag{III.7}$$

where r and s are the zones at the ends of the line whose outage is being tested. The LODF is given by

$$\text{LODF}_{ij,rs} = \frac{N_{rs} \cdot x_{rs}}{N_{ij} \cdot x_{ij}} \cdot \frac{(X_{ir} - X_{is} - X_{jr} + X_{js})}{[N_{rs} \cdot x_{rs} - (X_{rr} + X_{ss} - 2X_{rs})]} \tag{III.8}$$

where

x_{ij} and X_{ir} — are as in (III.5);

N_{ij} — number of circuits connecting zone i and zone j.

IV. The Optimal Power Flow (OPF) Solution

A. Introduction to OPF

OPF is a technology that has been used in the electric power industry for over 35 years. It gets its name from the fact that an optimization is performed to minimize generator operating costs. This is the exact same objective as the simpler economic dispatch (ED) function, but with an added set of constraints that represent a model of the transmission system within which the generators operate. When the transmission system is uncongested, the OPF solution is the same as the ED solution, so the explanation of OPF starts with ED.

1) ED: Conventional ED can be represented as a minimization of total generation cost as follows:

$$\min \sum_{\text{gen}i} C_i\left(P_{G_i}\right) \tag{IV.1}$$

subject to constraints

$$P_{G_i}^{\min} \le P_{G_i} \le P_{G_i}^{\max} \tag{IV.2}$$

and

$$\sum_{\text{gen}i} P_{G_i} = P_D \tag{IV.3}$$

where

P_{G_i}	power output of generator i;
$P_{G_i}^{\min}$ and $P_{G_i}^{\max}$	generator i's output limits;
P_D	total system load;
$C_i(P_{G_i})$	individual cost function for generator i.

The cost function is found from a heat rate curve, also called an input–output characteristic, which gives the generator electric power output in MW as a function of the thermal energy input rate (in MBTU/h or MJ/h) times the fuel cost per thermal energy unit. The heat rate curve is obtained from measured data. The resulting units for the cost function are then $/h as a function of MW. Generally the fit to measured data gives a monotonically rising function. The above problem formulation ignores the real power losses in the transmission system. Several methods can be used to add the effects of losses.

Historically, ED has been performed by each electric utility's control computer systems. The total load in the ED calculation is modified by adding the total export power or subtracting the total import power so that the result is actually the total generation MW desired within the utility's system.

2) OPF: The true OPF uses a formulation wherein the entire set of ac power flow equations are added to the economic dispatch as equality constraints so that as the calculation is run the cost of delivery of energy is minimized and a complete ac power flow solution (all complex voltage values) is reached. In addition, inequality constraints involving such things as the flow of MW, MVA, or current on a transmission line or the voltage at a substation bus can be incorporated in the OPF, and this makes it far more useful. Last of all, engineers have developed OPF calculations with ac power flow equations as equality constraints, inequality constraints on system flows and voltages, and then added constraints on flows and voltages that would be seen during contingency conditions. This OPF is then referred to as a security constrained OPF—or SCOPF. The difficulty in making a useful SCOPF is the fact that the system may not exhibit contingency problems at the start of the calculation, but only as the OPF adjusts generation do contingency constraints appear.

This paper will not go into the detailed use of full AC OPF or SCOPF calculations. For a useful discussion of these calculations see [4]. Instead, a rather simplified approach is taken as follows.

1) The ED formulation is augmented with the dc power flow equations.
2) A set of constraints is added.

The dc power flow equations appear in the problem formulation as an equality constraint. The net generator output power in each zone, P_{G_i}, is a variable while the net load power in each zone P_{D_i} is assumed to have zero price elasticity and thus be constant. (The next section will consider the case of some of the load having price elasticity.) Since the zone injections are

$$P_i = P_{G_i} - P_{D_i} \tag{IV.4}$$

the dc power flow (III.3) is rewritten

$$\begin{bmatrix} & & \\ & \mathbf{B_x} & \\ & & \end{bmatrix} \begin{bmatrix} \theta_1 \\ \vdots \\ \theta_n \end{bmatrix} - \begin{bmatrix} P_{G_1} \\ \vdots \\ P_{G_n} \end{bmatrix} = \begin{bmatrix} -P_{D_1} \\ \vdots \\ -P_{D_n} \end{bmatrix}. \tag{IV.5}$$

To guarantee that the OPF can be solved, one of the zones is chosen to have zero phase angle by setting its phase angle upper and lower limits to zero.

The constraints limit normal interface power flow and postcontingency interface power flow. The normal interface power flow limit constraint is

$$-P_{ij}^{\max} \le P_{ij} \le P_{ij}^{\max}. \tag{IV.6}$$

This can be expressed in terms of the phase angles (which are problem variables) by applying (III.1). A slack variable, s_{ij} is also added, giving

$$\frac{1}{x_{ij}}\left(\theta_i - \theta_j\right) + s_{ij} = P_{ij}^{\max}. \tag{IV.7}$$

The slack variable has a lower limit of zero and an upper limit of $2P_{ij}^{\max}$, so (IV.7) is the same constraint as (IV.6).

Similarly, the postcontingency interface flow limits are included in the OPF. If all $n-1$ contingencies were considered, there would be a constraint (and slack variable) for each circuit contingency for each interface. This would make the problem size too large for efficient computation. To limit the number of constraints, the OPF is solved without contingency constraints, a contingency analysis is performed, and then the OPF is resolved with new constraints added only for those contingency outages that result in overloads, and only for the interfaces that are overloaded. For a contingency outage of line mn and a resulting overload on interface ij, the added constraint is

$$-1.1 \cdot P_{ij}^{\max} \le P_{ij}^{C} \le 1.1 \cdot P_{ij}^{\max} \tag{IV.8}$$

where P_{ij}^{C} is the postcontingency flow on the interface from zone i to zone j. The factor of 1.1 appears because postcontingency interface limits are 10% higher than normal interface flow limits in the example system. Applying (III.1) and

Table 3
Generation and Price-Elastic Load Cost Data

Bid Number	Zone	b Constant	c Constant	Max MW
1	1	10.00	0.0040	1000.0
2	2	15.00	0.0060	800.0
3	3	50.00	0.0080	1500.0
4	4	12.00	0.0050	2500.0
5	5	15.50	0.0060	1500.0
6	6	15.50	0.0070	1500.0
7	7	21.50	0.0080	1500.0
8	8	16.00	0.0060	1500.0
9	9	14.00	0.0050	1500.0
10	10	13.00	0.0040	1500.0
11	11	16.00	0.0060	700.0
12	11	31.00	0.0090	2000.0
13	1	-200.00	0.0000	1000.0
14	2	-200.00	0.0000	1000.0
15	3	-200.00	0.0000	1000.0
16	4	-200.00	0.0000	1000.0
17	5	-200.00	0.0000	1000.0
18	6	-200.00	0.0000	1000.0
19	7	-200.00	0.0000	1000.0
20	8	-200.00	0.0000	1000.0
21	9	-200.00	0.0000	1000.0
22	10	-200.00	0.0000	1000.0
23	11	-200.00	0.0000	1500.0

(III.7), and adding a slack variable gives the constraint in the form

$$\frac{1}{x_{ij}}(\theta_i - \theta_j) + \mathrm{LODF}_{ij,\,mn} \cdot \frac{1}{x_{mn}}(\theta_m - \theta_n) + s_{ij,\,mn} = 1.1 \cdot P_{ij}^{\max}. \tag{IV.9}$$

Here the slack variable has a lower limit of zero and an upper limit of $2 \cdot 1.1 \cdot P_{ij}^{\max}$.

Generator cost functions are represented as quadratic functions

$$C_i(P_{G_i}) = a_i + b_i \cdot P_{G_i} + c_i \cdot P_{G_i}^2. \tag{IV.10}$$

The b and c constants are given in Table 3. Note that the value of the a constant does not affect the optimal solution. It is set to zero in the calculations used in this paper.

The quadratic cost functions make this OPF formulation a problem that can be can be solved with a quadratic programming (QP) algorithm. The QP algorithm used can accept upper and lower bound limits on each variable.

The complete OPF formulation is then

$$\min \sum_i C_i(P_{G_i}) \tag{IV.11}$$

subject to the generator limit constraints

$$P_{G_i}^{\min} \le P_{G_i} \le P_{G_i}^{\max} \tag{IV.12}$$

subject to the dc power flow equations

$$\begin{bmatrix} & & \\ & \mathbf{B_x} & \\ & & \end{bmatrix} \begin{bmatrix} \theta_1 \\ \vdots \\ \theta_n \end{bmatrix} - \begin{bmatrix} P_{G_1} \\ \vdots \\ P_{G_n} \end{bmatrix} = \begin{bmatrix} -P_{D_1} \\ \vdots \\ -P_{D_n} \end{bmatrix} \tag{IV.13}$$

subject to normal interface flow constraints

$$\frac{1}{x_{ij}}(\theta_i - \theta_j) + s_{ij} = P_{ij}^{\max} \tag{IV.14}$$

and subject to contingency constraints for all active contingencies

$$\frac{1}{x_{ij}}(\theta_i - \theta_j) + \mathrm{LODF}_{ij,\,mn} \cdot \frac{1}{x_{mn}}(\theta_m - \theta_n) + s_{ij,\,mn} = 1.1 \cdot P_{ij}^{\max}. \tag{IV.15}$$

The variables in the OPF are: n zone phase angles θ_i, where n is the number of zones; n zone generator power outputs P_{G_i}; m normal interface flow slack variables s_{ij}, where m is the number of interfaces; and r postcontingency interface flow slack variables $s_{ij,\,mn}$, one for each active contingency.

3) Inclusion of Load in the OPF Objective Function: When the loads in the power system are assumed to have zero price elasticity, meaning that they do not change as prices change, then the OPF objective function is just generation cost and the objective is to minimize total generation cost subject to all the constraints. An alternative assumption is that some of the load has price elasticity, that is, energy to supply the load will be purchased only if the cost to the load is low enough—otherwise the load will be shut off. The OPF can be used to represent price-elastic load as long as a "cost function" for the load is provided. The load's "cost" is negative, because the load pays, and represents the worth of the energy to the load.

In this case, the generator cost function $C_i(P_{G_i})$ is actually a function that represents the asking price or bid (in $ for a given MWh amount) that the generation owner is presenting to a pool or independent system operator (ISO) where the OPF is to be run. The worth function for the portion of the load that is price elastic is $W_i(P_{E_i})$. It represents the price (in dollars) the load is willing to pay to purchase an amount of power P_{E_i}, and thus the load's bid to the pool or ISO.

The OPF objective function should then seek to minimize costs and maximize worth, subject to the constraints. The new objective function is

$$\min \left[\sum_i C_i(P_{G_i}) - \sum_i W_i(P_{E_i}) \right] \tag{IV.16}$$

and the OPF will determine the proper clearing price for the pool. The dc power flow constraint must be reformulated to include price-elastic load as follows:

$$\begin{bmatrix} & & \\ & \mathbf{B_x} & \\ & & \end{bmatrix} \begin{bmatrix} \theta_1 \\ \vdots \\ \theta_n \end{bmatrix} - \begin{bmatrix} P_{G_1} - P_{E_1} \\ \vdots \\ P_{G_n} - P_{E_n} \end{bmatrix} = \begin{bmatrix} -P_{D_1} \\ \vdots \\ -P_{D_n} \end{bmatrix}. \tag{IV.17}$$

4) The Meaning of Lagrange Multipliers: Any optimization problem will have a Lagrange multiplier λ associated with each equality constraint in the problem. In the case of the OPF we are using in this section, the Lagrange multiplier associated with each constraint represented by the power flow equations is the derivative of the total cost with respect to the increase in that zone's load. This derivative can then be looked at as the instantaneous price of the next small increment of load—or simply the zone price in \$/MWh.

If there are no interfaces that are congested, then the zone price for all zones will be equal. In that case the increase in a zone load may be met by an increase in output by a generator in that zone, or by an increase in generation in another zone (or by an increase in many generators in many zones). The generators which would increase to supply the next increment of load are the lowest cost generators which are still free to move up—that is, generators not at their maximum output.

When congestion occurs, zone prices across the system are different. This is because the increase in load in a zone may not come from the lowest cost generators due to the fact that a contingency or interface limit prevents the generation from increasing. Several examples of this phenomena are given in later parts of this section.

In a full ac OPF, even the uncongested case will have different zone prices in each zone. This is due to the effects of transmission losses. The difference between zone prices equals the value of marginal losses between the zones. This paper assumes a lossless transmission system to focus on congestion issues, but losses are an important issue in transmission management.

B. Using the OPF in a Deregulated Power System

The use of the OPF and zone incremental costs or zone prices (in \$/MWh, also called locational marginal prices, or LMP's) has been put into practice in such ISO's as the PJM Interconnection in the United States. Generators send a cost function (an asking price function) and those wishing to purchase load send a bid function to the ISO. The ISO has a complete transmission model and can then do an OPF calculation. The zone prices determined by the OPF are used in the following manner.

1) Generators are paid the zone price for energy.
2) Loads must pay the zone price for energy.

If there is no congestion, there is one zone price throughout the system, and the generators are paid the same price for their energy as the loads pay. When there is congestion, zone prices differ, each generator is paid its zone's price, and each load pays its zone's price for energy.

If there are no losses in the transmission system (a situation that is obviously an approximation as real transmission systems always have I^2R loss in the lines and transformers) then an interesting accounting can be done with the zone prices, the generation, and the load. With no congestion the following holds true:

$$\sum_{\text{all zones } i} \pi_i \cdot P_{D_i} = \sum_{\text{all zones } i} \pi_i \cdot P_{G_i} \qquad \text{(IV.18)}$$

where π_i is the price in zone i. That is, all of the money collected by the pool from the loads goes to pay the generators. However, when there is congestion

$$\sum_{\text{all zones } i} \pi_i \cdot P_{D_i} \neq \sum_{\text{all zones } i} \pi_i \cdot P_{G_i}. \qquad \text{(IV.19)}$$

Table 4
Base Case Generation and Price-Elastic Load OPF Results

Bid Number	Bid Zone	Max MW	MW Sold or Purchased	Generator Incremental Cost
1	1	1000.0	1000.0	18.00
2	2	800.0	800.0	24.60
3	3	1500.0	0.0	50.00
4	4	2500.0	1864.4	30.64
5	5	1500.0	1262.0	30.64
6	6	1500.0	1081.7	30.64
7	7	1500.0	571.5	30.64
8	8	1500.0	1220.3	30.64
9	9	1500.0	1500.0	29.00
10	10	1500.0	1500.0	25.00
11	11	700.0	700.0	24.40
12	11	2000.0	0.0	31.00
13	1	1000.0	1000.0	
14	2	1000.0	1000.0	
15	3	1000.0	1000.0	
16	4	1000.0	1000.0	
17	5	1000.0	1000.0	
18	6	1000.0	1000.0	
19	7	1000.0	1000.0	
20	8	1000.0	1000.0	
21	9	1000.0	1000.0	
22	10	1000.0	1000.0	
23	11	1500.0	1500.0	

In fact, there is always a surplus—the money collected from the loads is more than the money paid to the generators (see Appendix A)

$$\sum_{\text{all zones } i} \pi_i \cdot P_{D_i} > \sum_{\text{all zones } i} \pi_i \cdot P_{G_i}. \qquad \text{(IV.20)}$$

This surplus plays an important part in Section IV-D where the concept of transmission rights is introduced.

The OPF, through the pricing in the zones, performs the function of controlling the transmission flows (that is, maintaining transmission system security).

C. Examples of OPF Solutions

1) Base Case: Tables 1 and 3 give the base case transmission data and the generation and price-elastic load cost data—or bidding data—that is used throughout this section. In the base case the transmission system is as shown in Fig. 2. Contingencies are checked but no contingencies are binding at the optimal solution reached by the OPF. Tables 4 and 5 give the results for generation and price-elastic load.

All load is being supplied (they become price inelastic when they reach a maximum energy value) and all the generators are supplying some power with the exception of the generator in zone 3 and the second generator in zone 11, which are so expensive they are not used at all. Note that any generator which is not at its minimum or maximum operates at the same incremental cost. This solution is the same as would be obtained by economic dispatch.

In the base case all zones have the same zone price (λ). Note that zone 11 is importing 800 MW of power, its first generator is at its maximum output of 700 MW and its second generator is not producing anything. This is an example of

Table 5
Base Case Export/Import

Zone Number	Variable Generation	Variable Load	Zone Lambda	Total Export or Import
1	1000.0	1000.0	30.64	0.0
2	800.0	1000.0	30.64	-200.0
3	0.0	1000.0	30.64	-1000.0
4	1864.4	1000.0	30.64	864.4
5	1262.0	1000.0	30.64	262.0
6	1081.7	1000.0	30.64	81.7
7	571.5	1000.0	30.64	-428.5
8	1220.3	1000.0	30.64	220.3
9	1500.0	1000.0	30.64	500.0
10	1500.0	1000.0	30.64	500.0
11	700.0	1500.0	30.64	-800.0
Total	11500.0	11500.0		

Table 6
Base Case Transmission System Flows

Path	From	To	Low	Flow	High	Percent Loading
1	1	2	-2000.0	-111.7	2000.0	5.6
2	1	3	-1600.0	111.7	1600.0	7.0
3	2	3	-250.0	31.4	250.0	12.6
4	2	4	-3000.0	-267.6	3000.0	8.9
5	2	5	-1000.0	-75.5	1000.0	7.5
6	3	8	-1000.0	-562.8	1000.0	56.3
7	3	9	-400.0	-294.1	400.0	73.5
8	4	5	-2000.0	27.5	2000.0	1.4
9	4	6	-2000.0	206.9	2000.0	10.3
10	4	7	-3000.0	362.3	3000.0	12.1
11	5	7	-2000.0	214.1	2000.0	10.7
12	6	7	-2000.0	34.6	2000.0	1.7
13	8	10	-1600.0	-169.8	1600.0	10.6
14	8	9	-1000.0	-172.6	1000.0	17.3
15	9	10	-500.0	33.2	500.0	6.6
16	6	11	-1500.0	254.1	1500.0	16.9
17	7	11	-1200.0	182.5	1200.0	15.2
18	10	11	-500.0	363.4	500.0	72.7

a system with no congestion. The flows on this system are given in Table 6.

In this case, the transmission system can withstand any first contingency outage of a single circuit in any interface and still not be overloaded. Loads and generation can freely exchange power between themselves—which results in a uniform zone price of $30.64/MWh everywhere.

2) Congested Case: Without any changes to the economics of the base case, that is, with all generation cost and load worth functions the same, congestion is created by a change in the transmission system topology. All circuits in the interfaces between zones 6 and 11 and zones 7 and 11 have been completely outaged.

The resulting congested system export-import data is in Table 7.

The active or binding constraint is a contingency of one circuit in the zone 10 to zone 11 interface, which brings the remaining circuit in that interface to its postcontingency flow limit.

The congestion results in a reduction of import into zone 11 from 800 MW in the base case to 275 MW. This means

Table 7
Congested Case Export/Import

Zone Number	Variable Generation	Variable Load	Zone Lambda	Total Export or Import
1	1000.0	1000.0	29.33	0.0
2	800.0	1000.0	29.33	-200.0
3	-0.0	1000.0	29.33	-1000.0
4	1733.4	1000.0	29.33	733.4
5	1152.8	1000.0	29.33	152.8
6	988.1	1000.0	29.33	-11.9
7	489.6	1000.0	29.33	-510.4
8	1111.1	1000.0	29.33	111.1
9	1500.0	1000.0	29.33	500.0
10	1500.0	1000.0	29.33	500.0
11	1225.0	1500.0	40.45	-275.0
Totals	11500.0	11500.0		

Table 8
Congestion with Load Reduction

Zone Number	Variable Generation	Variable Load	Zone Lambda	Total Export or Import
1	1000.0	1000.0	29.33	0.0
2	800.0	1000.0	29.33	-200.0
3	-0.0	1000.0	29.33	-1000.0
4	1733.4	1000.0	29.33	733.4
5	1152.8	1000.0	29.33	152.8
6	988.1	1000.0	29.33	-11.9
7	489.6	1000.0	29.33	-510.4
8	1111.1	1000.0	29.33	111.1
9	1500.0	1000.0	29.33	500.0
10	1500.0	1000.0	29.33	500.0
11	1088.9	1363.9	38.00	-275.0
Totals	11363.9	11363.9		

that generation in zone 11 must increase from 700 to 1225 MW to supply zone 11 load, and this must all come from the very high priced second generator in zone 11. The reduction of 525 MW in generation exported from the remaining zones results in their zone lambdas dropping slightly to $29.33/MWh while zone 11 experiences an increase to $40.45/MWh.

3) Congestion with Reduced Load Served: To illustrate the fact that load need not always be served, the load bid for the load in zone 11 was reduced from $200/MWh to $38/MWh. The load in zone 11 will start to reduce the load purchased when the cost in zone 11 reaches $38/MWh. The OPF results are given in Table 8.

Here the load in zone 11 is reduced to 1363.9 MW and the generation produced by the second generator in zone 11 is reduced to 388.9 MW. Note that the zone lambda for zone 11 is now exactly $38/MWh. Since the load reduction was matched by the generator reduction in zone 11 the import remains the same as above.

4) Congestion in a Networked System: The changes to the network that caused congestion in the cases in Sections IV-C2 and IV-C3 made part of the system, the interface from zone 10 to zone 11, radial. (If that interface were removed, the system would be split into two disconnected islands.) When congestion occurred on the radial interface, only two

Table 9
Congestion in a Networked System

Zone Number	Variable Generation	Variable Load	Zone Lambda	Total Export or Import
1	1000.0	1000.0	30.44	0.0
2	800.0	1000.0	30.65	-200.0
3	-0.0	1000.0	30.17	-1000.0
4	1878.1	1000.0	30.78	878.1
5	1274.4	1000.0	30.79	274.4
6	1094.9	1000.0	30.83	94.9
7	585.9	1000.0	30.87	-414.1
8	1148.6	1000.0	29.78	148.6
9	1500.0	1000.0	29.80	500.0
10	1500.0	1000.0	29.53	500.0
11	718.1	1500.0	31.33	-781.9
Totals	11500.0	11500.0		

distinct zone prices appeared, one on each side of the interface.

When congestion appears on an interface which is part of a networked (meshed or looped) system, all of the zone prices are unique. Congestion on any interface in a networked system affects zone prices in the entire networked system. This is illustrated by restoring the interface from zone 7 to zone 11 to service. Only the interface from zone 6 to zone 11 is out of service. The load in zone 11 is price-elastic like the load in the previous case. The OPF results are given in Table 9.

Because of the increased interface capacity to zone 11, more power is imported and the more expensive generator in zone 11 now operates at only 18.1 MW. This lowers the zone 11 zone price below the price at which the price-elastic load would reduce purchases, so the entire load of 1500 MW in zone 11 is served.

A contingency on the interface from zone 10 to zone 11 is still the binding constraint, but this interface is now part of a networked system. As a result, every zone price is unique. This is because, thanks to Kirchhoff's Voltage Law, a change in load or generation in any zone will affect the flow on the congested interface, even when the changed load or generation is in a zone far removed from that interface. Higher zone prices appear where decreases in generator or increases in load increase the flow on the congested interface. Lower zone prices appear where increases in load or decreases in generation decrease the flow on the congested interface. Thus, some zones have prices higher than the radial congestion case in Section IV-C3, and some have lower prices.

D. Transmission Rights

As discussed in Section IV-B and as seen in the examples in Section IV-C, there is a surplus in monies collected by the ISO when there is congestion in the transmission system. Hogan of Harvard University [5] suggests that this extra money can be the source of a system of contract network rights. The idea behind contract network rights is to provide a mechanism to control the financial risks of congestion-induced price variations. These rights have been referred to by various names in different market implementations and discussions, such as Transmission Congestion Contracts in NYPP, Fixed Transmission Rights in PJM, Firm Transmission Rights in California, Financial Congestion Rights in ISO New England, and Financial Transmission Rights by FERC. The generic expression contract network rights is used here to avoid confusion with any specific implementation of the concept.

Assume that a generation company has a contract to supply electric energy to a load in another zone of the power system. For example, suppose a generation company in zone 8 has a contract with a load purchasing company in zone 11. The terms of this contract state that the load will pay for electric energy at the marginal cost of the generation company in zone 8. However, the load actually is billed by the pool or power exchange governing the operation of the transmission system at the load's zone price. Similarly, the pool or exchange then pays the generation company at the generator's zone price.

As shown in Table 5, when there is no congestion the price paid by the load in zone 11 is the same as the price paid to the generation company in zone 8. That is, $\pi_{11} = \pi_8$. With major transmission out of service, the price in zone 11 jumps to a much higher value than the price in zone 8, that is, $\pi_{11} > \pi_8$. The pool bills the load at π_{11} and pays the generator at π_8. The load contacts the generator and says that the generation company, by contract, owes the difference to the load, that is, the load pays $\pi_{11} \cdot P_{D_{11}}$ and the generator is paid $\pi_8 \cdot P_{G_8}$ where $P_{D_{11}} = P_{G_8}$. The generator now must pay $(\pi_{11} - \pi_8) \cdot P_{D_{11}}$ to the load company, with the result that as far as the load company is concerned, it has paid $\pi_8 \cdot P_{D_{11}}$.

The generation company's income and profits are decreased by such an arrangement. However, it can purchase a contract network right for $P_{D_{11}}$ MW from zone 8 to zone 11 ahead of time. This contract says that if the prices in zone 8 and zone 11 are not equal, then the pool or power exchange will reimburse the contract holder—in this case the generation company in zone 8—the difference in price times the MW being transferred from zone 8 to 11. That is, the pool now pays the generation company $(\pi_{11} - \pi_8) \cdot P_{D_{11}}$, and this provides compensation for the extra payment that the generation company had to make to the load to fulfill its contract. The pool has the funds to do this through the surplus collected due to the price difference. Therefore, the load gets its energy at the contract price and the generation company gets paid at the zone price it is experiencing.

There are several things to note.

1) A load or a generation company may purchase a contract network right to protect itself against zone price swings due to congestion.
2) When the transmission system is experiencing congestion, a zone that cannot import any additional power due to the congestion may experience high prices from local generation companies who know that they have market power through a captive set of customers—they have to buy from them. Owning a contract network right will protect loads and external

generators with contracts to supply power at a lower price from such high prices.

3) The pool or power exchange that sold the contract network rights would be subject to losses if it sold rights to transfer energy that were in excess of the transmission capacity across a congested interface. Some possible options to protect the seller would be insurance, or to only sell up to the minimum capacity of the interfaces when the worst contingency occurred.
4) If the pool would only sell a limited amount of rights to transmission, they might not be available for all the loads in the congested area. Some would be protected, some unprotected, and those that were unprotected would be subject to the risk of high prices during congestion.

The examples given in Section IV-C show the differences in transmission congestion charges. The paragraph below assumes that the costs are for one hour of operation.

Without congestion, the loads pay the power pool or ISO a total of \$352 407.50 (this is the sum of each zone's load in MW times its zone price in \$/MWh times 1 h). The generation is paid the same amount of \$352 407.50 (by summing each zone's generation MW times its zone price times one hour). Since all the zone prices are equal there are no transmission congestion charges.

In the congested case the loads pay \$354 010.81 and the generators are paid \$350 953.79, which is not the same. The pool or ISO collects \$3057.02 more than it pays out. If one takes the difference in zone price at the "from" zone and "to" zone of each interface and multiplies this difference times the MW flowing over the interface, the result is \$3057.02, which is called the transmission congestion surplus or congestion rent. The load in zone 11 is now paying \$40.45/MWh instead of the incremental cost of \$29.33/MWh for the generator in zone 8 (assuming as above that the zone 11 load has a contract with the generator in zone 8). The difference in zone prices from zone 11 to zone 8 is $(40.45-29.33) =$ \$11.12/MWh. If this is multiplied by the 275 MW of capacity being used on the zone 11 to zone 10 interface, using unrounded values the exact amount of \$3057.02 necessary to reimburse the zone 11 load for its higher payment is obtained.

E. Economics and Transmission Congestion

The ideal of economists is to create a marketplace that is "efficient"—by which is meant a marketplace where producers make products that consumers want and do so at the least possible cost. In the electric power open marketplace this would imply that all consumers of electric energy could purchase energy at the same price no matter where they were. If the transmission systems had unlimited capacity to transfer energy, generation companies would all have to operate with nearly the same technological level so that they would all be producing electric energy at nearly the same price and could send their energy to any load customer no matter where that customer was located. Obviously, the transmission system limits the ability to transfer energy. Energy from generation that is low priced cannot always be transferred to load customers wanting to make purchases, and those customers are then forced to purchase from higher priced generation which is located so as not to be subject to limitation by the transmission system. Therefore the transmission system is said to introduce a degree of inefficiency into the electric power marketplace.

A generation company that frequently finds itself within a region or zone of the power system that is limited in ability to bring in less expensive energy is said to be able to exercise "market power"—meaning that it can raise prices almost to any level and customers will pay those prices if they need the electric energy badly enough. Use of the OPF and contract network rights go a long way toward mitigating market power and making the transmission system efficient—as long as there is normally enough transmission capacity to sell contracts to any customer or generation company that desires them. This may not always be the case.

V. Tariffs, Price Areas and Buyback—The Nord Pool Congestion Solutions

The Nord Pool deregulated system presently comprises Norway, Sweden, and Finland, with Denmark soon to join. In contrast to deregulated systems in the UK and elsewhere, the Nordic deregulated system does not include a central scheduling/dispatching entity, only a central power exchange (Nord Pool). Scheduling is the responsibility of individual generating companies [6]. There is one power exchange (Nord Pool) and three system operators (SO's), each tied to a national grid company.

The fact that scheduling and dispatch is left to the market participants on the basis of individual profit maximization, brings the Nord Pool solution closer to a real free market than other deregulated systems.

Congestion in the Nord Pool system is managed with three different techniques, tariffs, price areas and buyback. The SO's use different combinations of the techniques, although all use buyback to control congestion during real time operation. These techniques are applied at different points during the market operation process.

A. Market Description

The so-called organized markets are centralized and based on a standardized bidding procedure. Presently there are three different organized markets.

1) *The spot market* is settled daily at noon for delivery for 24 h following the first midnight. The participants submit their bids for buying and selling on an hourly basis. These individual bids are aggregated by the market operator to form total supply and demand curves. Where the curves intersect, a clearing price and quantity is determined. The price area congestion management mechanism operates with the spot market.
2) *The regulating market* is used to adapt generation to the variations in the load. Producers submit their bids

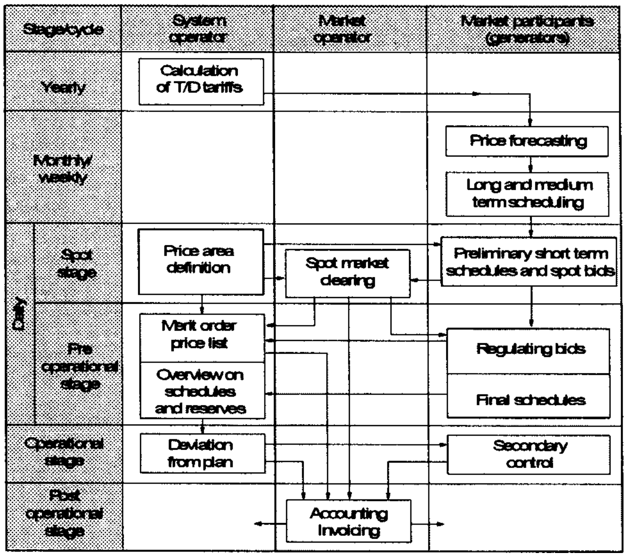

Fig. 4. Activities of different entities.

to the system operator on how much they are willing to regulate up or down, at what prices, and for how long. In real-time operation, the system operator picks the cheapest available regulator from the merit order list. The price in the regulating market is therefore settled *ex post*, when the price of the marginal regulator in each hour is known. All the regulators receive the price of the marginal regulator. The regulating market is the mechanism through which real time generation adjustments are obtained for the buyback congestion management mechanism.

3) *The futures market* with a weekly time resolution is a purely financial market. As is common to many futures markets, trading is more extensive in the near future than in the far future. The futures market is settled against the uncongested spot market clearing price, so that futures contracts do not provide a hedge against congestion.

In addition to these organized markets, the system is open for bilateral trade, which accounts for about two thirds of turnover in the Norwegian energy market.

B. Market Process

Operations planning is performed in a dynamic interplay between the three main parties in the system: 1) the market participants on the supply and demand side; 2) the system operator; and 3) the market operator. The interaction of these entities is indicated in Fig. 4. (The figure shows the Norwegian version. Certain details are different in Sweden and Finland.) The entities are the following.

1) *Market participants* are buyers and sellers in the market place. They can be generating companies, utilities with distribution and more or less generating capacity, or end users. The SO is also a market participant because it buys grid losses in the spot market.
2) *The market operator* or exchange (Nord Pool) is responsible for the market clearing process in the spot market (24 h market) and the futures market. Accounting and invoicing is also a responsibility of the market operator.
3) *The system operator*, which in Norway is called Statnett, and is also the operator of the transmission network and owner of 80% of this network.

C. Transmission Tariffs and Congestion

Each generator and load pays a connection fee, or point tariff, to the network to which it is connected. There are three network levels: national; regional; and local. Each network pays a point tariff or connection fee to the higher level network to which it is connected. User point tariffs give the user access to all network levels for buying or selling energy. Thus, a load attached to a local network, paying the local network point tariff, can purchase energy from a generator attached to the Norwegian, Swedish, or Finnish grid. There is no tariff paid for transfer between the national networks.

The point tariff has three components. The investment charge is a one time charge imposed for major new connections. The energy charge, per MWh, is intended to adjust user costs to obtain a market solution that is optimal for transmission losses and is based on incremental loss coefficients. The capacity charge, based on peak MW consumed or generation capacity (physical capacity in Norway, declared capacity limit in Sweden), compensates the networks for their remaining expenses. The regional and local networks account for the largest portion of this charge.

In Sweden, the capacity charge varies geographically. Power flow in Sweden is always from north to south, so generation is charged more and load less in the northern part of the country. The variation in the tariff is linear with latitude. The intent is to provide an economic signal to new generation to locate in the south, and to new loads to locate in the north, thus easing congestion, which appears primarily on transmission lines running from north to south in Sweden. Thus, the tariff is used to deter congestion in the long term. Essentially the same philosophy is used in Finland. The United Kingdom has a similar geographically variable generator tariff system, although it is not based on latitude.

D. Price Area Congestion Management

Norway has a philosophy for congestion management that is different from Sweden and Finland. The existing system permits these philosophies to coexist without serious conflict. Norway seeks to effectively prevent congestion by using the spot market settlement process. When congestion is predicted, the SO declares that the system is split into price areas at predicted congestion bottlenecks. Spot market bidders must submit separate bids for each price area in which they have generation or load. If no congestion occurs during market settlement, the market will settle at one price, which will be the same as if no price areas existed. If congestion does occur, price areas are separately settled at prices that satisfy transmission constraints. Areas with excess generation will have lower prices, and areas with

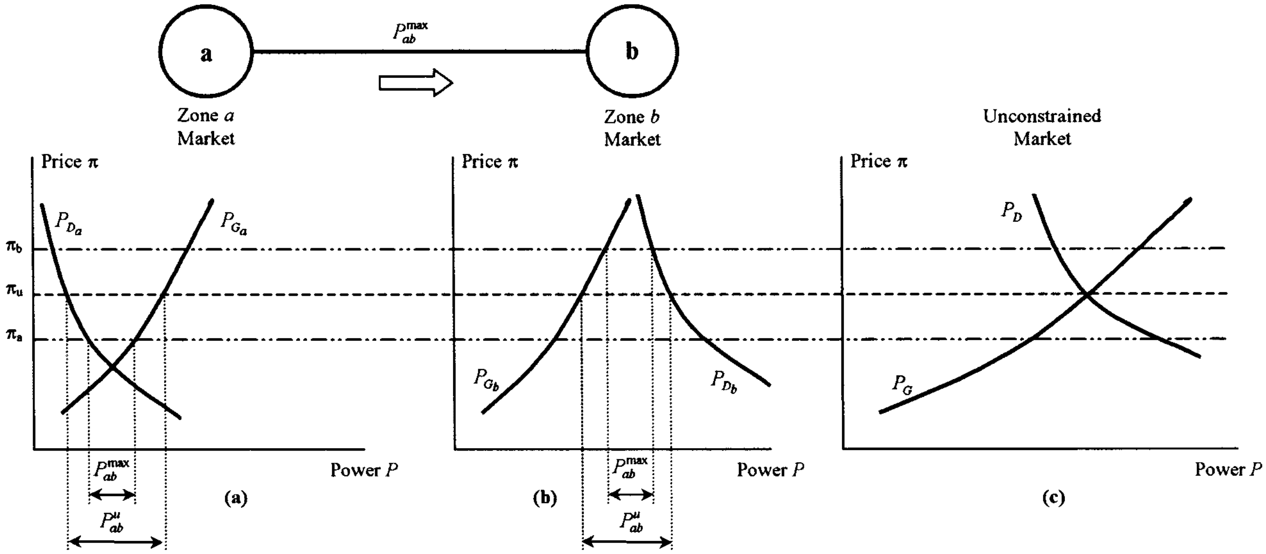

Fig. 5. Two zone price area example.

excess load higher prices. Market income from this price difference is paid to the SO and is used to reduce the capacity fee. Bilateral contracts that span price areas must purchase the load's energy in its price area in order to account for the contribution to congestion and to expose the contract to the financial consequences of congestion. It is the only instance of mandatory spot market participation.

Sweden's philosophy is that the transmission system should not affect the market resolution. Consequently, Sweden is always one price area, and does not use price areas to control internal congestion. Congestion rents collected between Sweden and other price areas are split between the SO's.

1) Two Zone Price Area Example: Price area congestion management is illustrated with a simple two zone example and then extended to multiple radially connected zones. Consider the two zone system at the top of Fig. 5 (adapted from [22]), with maximum power transfer limit $P_{ab}^{\max}$. Let generation and load bids in each zone be P_{G_a}, P_{G_b}, P_{D_a}, and P_{D_b}. With no congestion, the market will settle at a single unconstrained market price π_u, and total generation and load will be equal

$$P_{G_a} + P_{G_b} = P_{D_a} + P_{D_b}. \tag{V.1}$$

This case is illustrated in Fig. 5(c), which shows the unconstrained market settlement. The total generation and load curves P_G and P_D are aggregated from the two zones, i.e.,

$$P_G = P_{G_a} + P_{G_b}. \tag{V.2}$$

The unconstrained market solution, where the aggregated generation and load curves cross, gives the required unconstrained transfer P_{ab}^u

$$P_{ab}^u = P_{G_a}^u - P_{D_a}^u. \tag{V.3}$$

The unconstrained transfer P_{ab}^u appears as the distance between the zone generation and load curves at the unconstrained market price, i.e., between P_{G_a} and P_{D_a} at π_u, as seen in Fig. 5(a) and (b), which represent the zone a and zone b markets, respectively.

When the unconstrained transfer exceeds the transfer limit, then each zone becomes a separate price area, and the zone markets are separately resolved. The power balance constraint in zone a is that generation equal load plus transfer. The value of transfer is the maximum transfer limit

$$P_{G_a} = P_{D_a} + P_{ab}^{\max}. \tag{V.4}$$

This difference appears as the distance between the generation and load bid curves for zone a at the new zone a constrained market price π_a. The constrained price is less than the unconstrained price because of the excess of generation in zone a, as shown in Fig. 5(a). For zone b the effect of the transfer limit is opposite from zone a. The zone b constraint is

$$P_{G_b} = P_{D_b} - P_{ab}^{\max} \tag{V.5}$$

and zone b constrained price π_b is higher than the unconstrained price, as shown in Fig. 5(b). Taken together, the two zone constraints may be added to obtain the overall system power balance constraint of (V.1).

2) Multizone Price Area Example: Price area congestion management is illustrated by taking the eleven zone example and removing interfaces until the system is completely radial, as shown in Fig. 6. (The example system is not related to the actual Nord Pool transmission system.) The first step is to establish the price areas shown on the diagram. This can be done by comparing the power flows resulting from an unconstrained ED solution with interface transfer limits. Interface transfer limits in the radial case are simply the physical transfer limits of the circuits in the interface. This is the minimum of the sum of circuit capacity and the sum of postcontingency limits with one circuit out. These limits are found to be violated on the interfaces between zones 2–3 and 10–11.

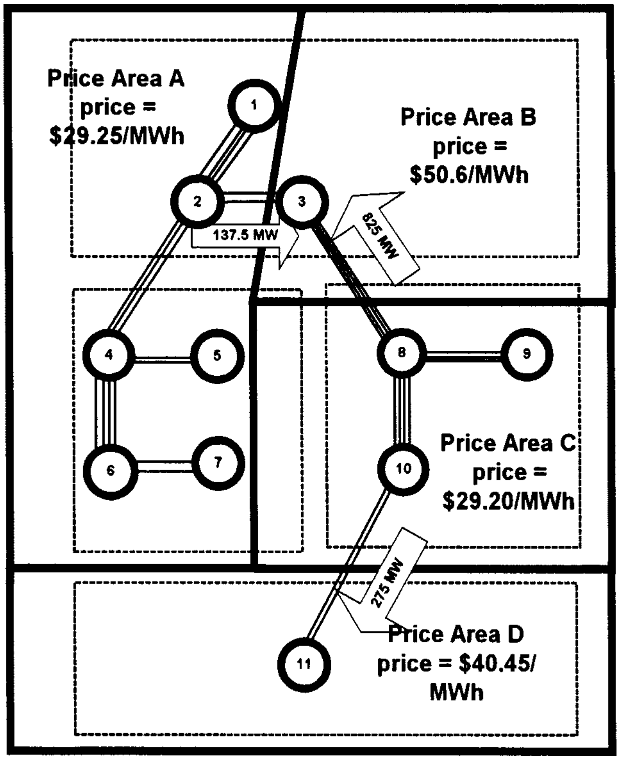

Fig. 6. Eleven zone model as a radial system.

Table 10
Price Area Prices

Price Area	Price ($/MWh)
A	29.25
B	50.6
C	29.20
D	40.45

Table 11
Radial System OPF Solution

Zone Number	Variable Generation	Variable Load	Zone Lambda	Total Export or Import
1	1000.0	1000.0	29.25	0.0
2	800.0	1000.0	29.25	-200.0
3	37.5	1000.0	50.6	-962.5
4	1725.0	1000.0	29.25	725.0
5	1145.9	1000.0	29.25	145.9
6	982.2	1000.0	29.25	-17.8
7	484.4	1000.0	29.25	-515.6
8	1100.0	1000.0	29.2	100.0
9	1500.0	1000.0	29.2	500.0
10	1500.0	1000.0	29.2	500.0
11	1225.0	1500.0	40.45	-275.0
Totals	11500.0	11500.0		

The zone 2–3 transfer limit, for example, is based on one circuit out, leaving one circuit with a contingency rating of 137.5 MW, while the unconstrained flow on this interface (found from Table 5) would be 579.6 MW. The zone 10–11 transfer limit is 275 MW with unconstrained flow of 800 MW. These overloaded interfaces define price area boundaries.

Once these overloaded interfaces are used to define price areas and constraint transfer, new flows will appear on other interfaces, and additional overloads may occur. In this case, a flow of 862.5 MW will appear on the zone 3–8 interface when the zone 2–3 and 10–11 constraints are applied. Since the zone 3–8 interface transfer limit is 825 MW, this interface also defines a price area boundary. No further overloads occur.

In practice, the transmission system is never truly radial, although it may be strongly radial, that is, behave for most practical purposes like a radial system. Price areas are defined pragmatically, based on operating experience and engineering judgment. Analytical determination of price area boundaries in a system that is not actually radial is an unsolved problem.

If the direction of power flows across price area boundaries is known, the generation requirement for each price area can be determined and used to resolve a market within that price area, just as in the two-zone example above. This is most easily illustrated in price area B, containing zone 3. Load in price area B is 1000 MW. (Price elasticity will not affect this result because the worth of electricity to the load is so high.) Power flow will be into the area on both interfaces, and each it at its interface flow limit, so the total inflow will be 962.5 MW. This means that 37.5 MW must be bought within price area B from the zone 3 generator. Assuming that the generator is a price taker (since it actually represents a large number of generators in the zone), it will bid its incremental costs to maximize its profits, and the market clearing price for area B will be $50.6/MWh. Similar calculations involving more generators result in the market clearing prices for the other price areas shown in Table 10.

It is interesting to note that submitting the same power system and economics to the optimal power flow gives exactly the same solution, as long as the system is radial. Table 11 gives the OPF results.

As in OPF, the market operator collects congestion rents from price area congestion management. For example, the market operator "buys" 137.5 MWh at $29.25/MWh from price area A and "sells" it at $50.6/MWh in price area B, collecting $2935.62. Presently, this congestion rent is given to the SO by the market or split between two SO's when the price area boundary is also the boundary between the SO's.

E. Buyback Congestion Management

Congestion in postmarket schedules or appearing in real time is corrected by purchase of generation raise and lower energy blocks from the SO regulating markets. This is known as buyback. In Sweden, buyback is the main congestion management tool, while in Norway buyback is used for minor adjustments and responding to outages.

The regulating market is a general purpose real time generator adjustment mechanism used for Automatic Generation Control (AGC), for example, as well as congestion management. Price-taking generators will bid incremental costs to the regulating market as well as the energy market, so in theory adjustments can be made at costs near the market clearing prices. For example, suppose that the flow on the interface from zone 2 to zone 3 was 1 MW too high. The system operator would call on the generator in zone 3 to raise 1 MW, which would be at a price of \$50.6/MWh, and on the generators in the first price area (which contains zone 2) to lower by 1 MW, for which the generators would pay the SO the price area price of \$29.25/MWh. The SO would have a net cost to make this adjustment of $(50.6 - 29.25) \cdot 1 = \$21.35$ for 1 h. The SO recovers the cost of buyback congestion management from its transmission tariffs, although there is not a direct correlation between any element of the tariff and buyback costs.

F. Summary

The Nord Pool deregulated structures and mechanisms, including congestion management techniques, are based on prederegulation practices modified by relatively slow evolutionary changes. Congestion has recently been frequent in the Nord Pool market area, but price differences are normally small. In Norway, the congestion rent is less than 1% of Statnett's income, and the Swedish SO, Svenska Kraftnät has correspondingly low costs for buyback expenses.

Experience has shown that Nord Pool can live with three different SO's and with different (but coordinated) solutions to tariffs, congestion management, etc. But certain problems have been seen and the solution is certainly not optimal. One problem is that different transmission tariffs can give a competitive advantage to generators in one country compared to another. The establishment of one common system operator is being discussed. That will not only include the establishment of one institution instead of three, but will probably also necessitate an institution independent of the transmission owners, i.e., instead of three SO's there will be one ISO.

VI. The U.S. Transaction-Based Solution

The U.S. government was faced with a situation quite different from that in many countries when it came time to deregulate its electric power system. Most of the electric power in the United States is generated by privately owned regulated utilities. The federal government is limited in what it can do to force these private companies to separate generation from transmission and distribution to enable competition and is reluctant to impose centralized solutions on the various states. The strategy adopted was to impose the minimum set of requirements that would create competition and to encourage regions to develop more complex structures.

The national deregulation structure is thus superposed on vastly different regional deregulation structures such as the California ISO (price area congestion control) and the PJM Interconnection (OPF). All such regional structures must operate in ways consistent with the federal requirements. The mechanisms discussed here apply to electric power transactions that span the boundaries of these regional structures.

A. Available Transfer Capability (ATC)

The U.S. Federal Energy Regulatory Commission (FERC) began the federal deregulation process by requiring "open access" to transmission services, so that all companies owning generation would have equal opportunity to locate and obtain transmission service between their generation sites and their customers. At the same time the reliability of the transmission system would be maintained. Furthermore, FERC wanted to do this in a way that did not require the government itself to be a part of operating the interconnected power system.

FERC's rulings were predicated on a decentralized system where regional transmission would be operated by ISO's. Each ISO would be responsible for monitoring its own regional transmission system and calculating the available transfer capability (ATC) [7] for potentially congested transmission paths entering, leaving and inside its network. ATC would be a measure of how much additional electric power (in MW) could be transferred from the starting point to the end point of a path. The ATC values for the next hour and for each hour into the future would be placed on a website known as the open access same-time information system (OASIS), to be operated by the ISO. Anyone wishing to send a power transaction on the ISO's transmission system would access OASIS web pages and use the ATC information available there to determine if the transmission system could accommodate the transaction, and to reserve the necessary transmission service.

The path-based ATC concept encountered problems soon after implementation. Within ISO regions, the number of paths on which congestion appeared grew rapidly. Between ISO regions, transmission services which had been reserved often had to be cancelled during actual operation to maintain system security. The cause was a mismatch between the actual power system and the ATC concept.

B. Network Flow Models and ATC

Network flow models (also called transportation models) look a lot like a transmission system. The nodes are sources and sinks, corresponding to buses with generation and load, and links between the nodes with transfer limits correspond to transmission lines. The amount of material entering a node must equal the amount leaving. This is the equivalent of Kirchhoff's Current Law (KCL), one of the fundamental laws of physics that apply to the transmission system. KCL requires that the sum of energy flow into a zone equal the sum of energy flow out of the zone. Network flow models have been studied extensively in economics. They apply to areas such as communication networks, airline flight paths, gas pipelines, and highway traffic.

Flow from a node in a network flow model has a free choice of links. Thus, in Fig. 2, a 1000-MW flow leaving zone (node) 1 could be directed entirely to zone 2, or entirely to zone 3, or split between the zones in any desired ratio. The ATC between any two zones can be found by considering the minimum interface rating on the various paths between the zones. For example, the ATC from zone 1 to zone 11 is 2750 MW. One possible set of paths for this is 1500 MW on path 1-2-4-6-11, 500 MW on path 1-2-5-7-11, 250 MW on path 1-3-2-5-7-11, and 500 MW on path 1-3-8-10-11. A large number of variations are possible on the paths without affecting this ATC value.

The problem with network flow models is that they do not apply to transmission systems. In the transmission system, the amount of power flowing on each link leaving a node is determined by Kirchhoff's Voltage Law. The split of power flow is determined by the electrical impedances in the entire transmission system. The fraction of the power going down one path cannot be changed unless very expensive phase shifting transformers or high voltage power electronics equipment is installed on a majority of the paths. The power flow can be computed using numerical algorithms like the dc power flow described in Section III. The results from this algorithm for a 1000-MW transaction from zone 1 to zone 11 are shown in Fig. 3. The 1000-MW power flow leaving zone 1 splits into 714 MW to zone 2 and 286 MW to zone 3. If the network in Fig. 3 were a network flow model, the split of power between path 1-2 and path 1-3 could be easily changed. In the real transmission system, the split is fixed at 0.714 and 0.286, respectively.

Because the transmission system obeys Kirchhoff's Voltage Law, it cannot be modeled with a network flow model.

C. PTDF's and ATC

The ATC from zone 1 to zone 11 could be found using a dc power flow by varying the amount of the transaction until a limit is reached, but this is computationally inefficient. Instead, the power transfer distribution factors (PTDF's) described in Section III-C can be used to quickly calculate the maximum allowable flow.

As shown in Fig. 3, the transaction from zone 1 to zone 11 results in flows on all the interfaces in the system. Note that none of the interface power flows is at or greater than its interface rating. If the amount of the transaction is increased, the flows will reach a point where one interface reaches its limit. It is possible for two interfaces to reach their limit simultaneously, but they do not in this model. The transaction amount at which this occurs is the ATC between zone 1 and zone 11. When one interface reaches its limit, no more power may be sent from zone 1 to zone 11.

The PTDF can be used to directly calculate the ATC. A transaction from zone m to zone n creates a change in the flow on a line from zone i to zone j of ΔP_{ij}. The new flow on the line is the sum of the original flow P_{ij}^{o} and the change, and it must be less than the line's flow limit P_{ij}^{Max}

$$P_{ij}^{\mathrm{New}} = P_{ij}^{o} + \Delta P_{ij} \leq P_{ij}^{\mathrm{Max}}. \tag{VI.1}$$

Applying (III.6) and solving for the transaction amount

$$P_{mn,ij}^{\mathrm{Max}} \leq \frac{P_{ij}^{\mathrm{Max}} - P_{ij}^{o}}{\mathrm{PTDF}_{ij,mn}}. \tag{VI.2}$$

$P_{mn,ij}^{\mathrm{Max}}$ is the maximum allowable transaction amount from zone m to zone n constrained by the line from zone i to zone

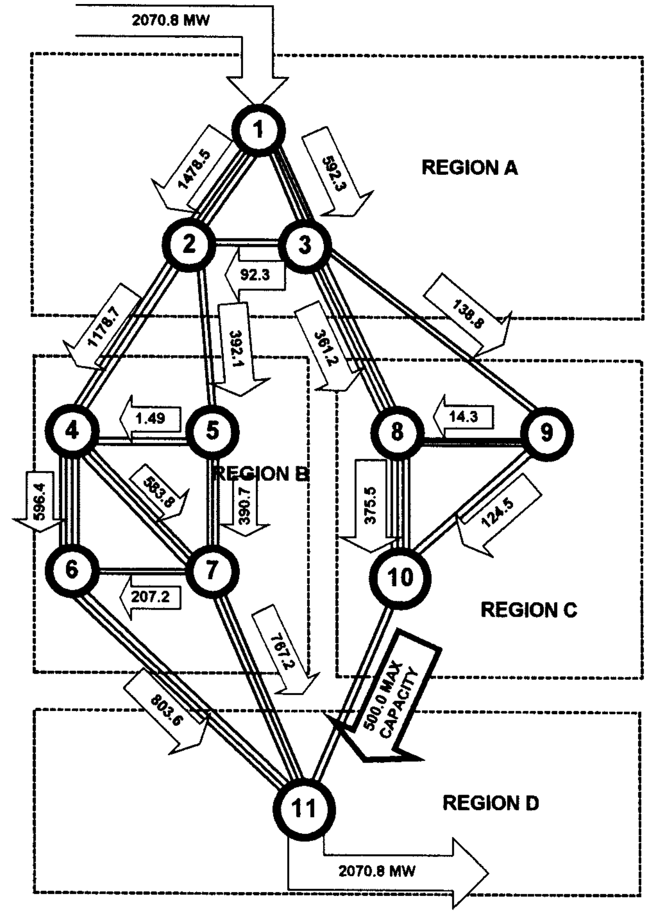

Fig. 7. Maximum transfer from zone 1 to zone 11 (limited by interface capacity only).

n is the minimum of the maximum allowable transaction over all lines

$$\mathrm{ATC}_{mn} = \min_{ij} P_{mn,ij}^{\mathrm{Max}}. \tag{VI.3}$$

For the example transaction between zone 1 and zone 11, the limiting interface is from zone 10 to zone 11, and the ATC is 2070.8 MW. This is shown in Fig. 7. This ATC value is 25% less than the network flow value found in Section VI-B.

D. Contingency Effects and the LODF

ATC is also limited by the effects of contingencies. The dc power flow could be used to calculate the effects of each line outage, and then the PTDF's applied to find transfer limits, but using LODF's can speed the computation. LODF's and PTDF's can be combined to calculate the first contingency incremental transfer capability, which is the maximum increase in transaction amount from one zone to another zone which still meets the $n-1$ test. Consider a transaction from zone m to zone n and the outage of a line from zone r to zone s (line rs). The change in flow on line rs due to the transaction is

$$\Delta P_{rs}^{\mathrm{New}} = \mathrm{PTDF}_{rs,mn} \cdot P_{mn}^{\mathrm{New}}. \tag{VI.4}$$

When line rs is outaged, part of the flow appears on line ij. Thus the change in flow on line ij resulting from both the outage of the line rs and a new transaction from zone m to zone n is given by

$$\Delta P_{ij,rs}^{\text{New}} = (\text{PTDF}_{ij,mn} + \text{LODF}_{ij,rs} \cdot \text{PTDF}_{rs,mn}) \cdot P_{mn}^{\text{New}}. \tag{VI.5}$$

Following the development of (VI.2), the maximum contingency limited transfer from zone m to zone n, limited by line ij with the outage of line rs, is given by

$$P_{mn,ij,rs}^{\text{Max}} \leq \frac{P_{ij}^{\text{Max}'} - P_{ij}^{o}}{\text{PTDF}_{ij,mn} + \text{LODF}_{ij,rs} \cdot \text{PTDF}_{rs,mn}}. \tag{VI.6}$$

Here, $P_{ij}^{\text{Max}'}$ indicates the postcontingency flow limit on line ij, which is usually higher than the steady-state limit.

To find contingency limited ATC, all possible combinations of outaged lines and limiting lines must be checked, as well as the steady state transfers. Thus

$$\text{ATC}_{mn,rs} = \min\left(\min_{ij} P_{mn,ij}^{\text{Max}}, \min_{ij,rs} P_{mn,ij,rs}^{\text{Max}}\right). \tag{VI.7}$$

Using the above equations, any proposed transaction for a specific hour may be checked by calculating the ATC. If it is greater than the amount of the proposed transaction the transaction is allowed. If not the transaction must be rejected or limited to the ATC.

In Fig. 8, the contingency limited transfer for a transaction from zone 1 to zone 11 has been calculated. The postcontingency line limits are 110% of the normal line limits. The limiting contingency is the outage of one line from zone 10 to zone 11. The interface rating drops to 275 MW (110% of the 250-MW normal rating). The precontingency flow shown in the arrows in Fig. 8 exceeds the postcontingency rating, but when the line outage occurs flow from zone 10 to zone 11 will drop to 275 MW due to the increased impedance of this path, as shown in the note in the figure.

The contingency limited ATC from zone 1 to zone 11 is 1608.5 MW. This is 41% less than the network flow ATC value from Section VI-B and 32% less than the no-outage ATC value from Section VI-C. Clearly contingency effects cannot be neglected in calculating ATC.

With the linear model used here, the contingency limited ATC is quite easily calculated. In real power systems, the calculation is often done with a series of full ac power flows or by using a linear programming optimization module to calculate ATC while making detailed adjustments to the generator voltages, transformers, and other controls to reach the true maximum transfer allowable and include nonlinear effects. The results are more accurate, but also more time consuming to compute.

E. Problems with Regional ATC Calculations

The use of ATC was first envisioned as a completely decentralized approach. Regions supervised by a single transmission operator, basically corresponding to regions of prederegulation transmission ownership, would each calculate ATC for paths within their region, and for paths leading into and out of their region. The ATC values would be posted on an OASIS web page and used by anyone in the marketplace to reserve transmission capacity for electric power transactions.

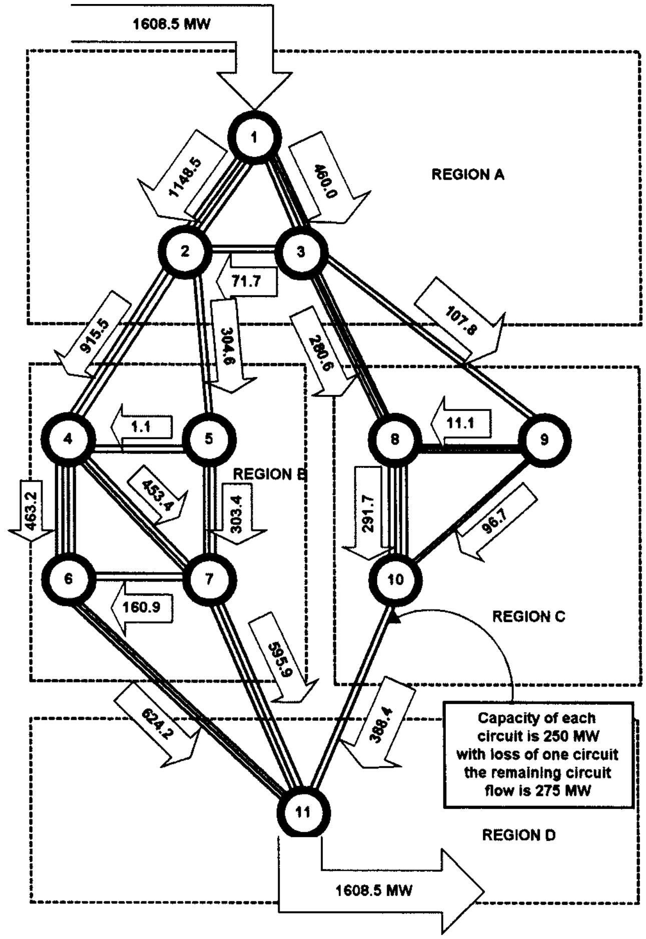

Fig. 8. Maximum transfer from zone 1 to zone 11 (limited by first contingency outage).

The distributed nature of this arrangement has some fundamental weaknesses related to a basic fact about ATC. When an ISO posts the ATC from node i to node j:

1) it means that the entire network is capable of carrying the posted ATC MW for a transaction whose source is at node i and whose destination is node j;
2) it does not mean that the ATC is the capacity of the interface connecting node i to node j.

The need to make the above point becomes clear if ATC is calculated for a transaction from zone 4 to zone 6. The contingency limited ATC is 3547.5 MW. Note especially that the capacity of the interface from zone 4 to zone 6 is 2000 MW, which is much smaller than the ATC. Simply put, the ATC measures the capability of the entire network to carry this transaction, and only part of it flows directly over the zone 4 to zone 6 interface.

One implication of this is that transactions that neither originate nor terminate in a zone can affect the ATC to or from that zone. This is illustrated in Fig. 9 where a 3000-MW transaction is taking place from zone 4 to zone 6. The zone 1

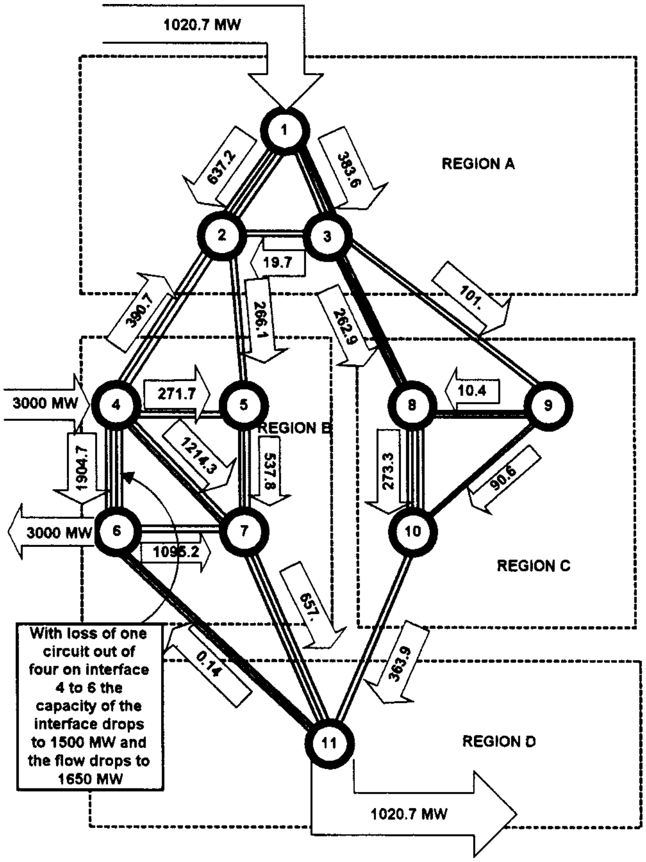

Fig. 9. Flow pattern with 3000 MW transaction from zone 4 to zone 6 and maximum ATC transaction from zone 1 to zone 11.

to zone 11 contingency limited ATC is reduced from 1608.5 to 1020.7 MW, without any transaction from zone 1 to zone 11. For accurate ATC calculations, each region must be aware of all transactions in the interconnected system.

A second implication affects reserving transmission services for transactions that span regional boundaries. The example power system has four regions: A; B; C; and D, as shown in Fig. 9. Assume each region has an ISO that operates the transmission system and is responsible for ATC calculations in its region. Each region will calculate contingency limited ATC values between zones in its region, and between zones in its region and zones in other regions with which it has a direct interface. It will not calculate ATC to zones that it is not directly connected to. (If it did, every region would solve the same problem, and there would be no point in decentralization.) The ATC values calculated and posted on each region's OASIS web page will be those in Table 12.

The ATC numbers in Table 7 are symmetrical in that the ATC from zone 1 to zone 2 is the same as that from zone 2 to zone 1. This is always the case in a linear model with no other transactions taking place on the power system. The ATC numbers become more interesting if a transaction is imposed, such as a 3000-MW transaction from zone 4 to zone 6. This transaction "uses up" some of the transmission system's capability to carry power in region B, but the transaction from zone 4 to zone 6 also affects the ATC for all other regions as

Table 12
ATC Values with No Other Transactions on the Transmission System

REGION A ATC		REGION B ATC		REGION C ATC		REGION D ATC	
FROM-TO	MAX MW	FROM-TO	MAX MW	FROM-TO	MAX MW	FROM-TO	MAX MW
1-2	2070.1	4-5	3408.7	8-9	1467.2	11-6	2230.8
2-1	2070.1	5-4	3408.7	9-8	1467.2	11-7	2223.1
1-3	1761.2	4-6	3547.5	8-10	1926.7	11-10	660.8
3-1	1761.2	6-4	3547.5	10-8	1926.7		
2-3	1390.6	4-7	4830.3	9-10	1147.3		
3-2	1390.6	7-4	4830.3	10-9	1147.3		
2-4	3259.0	5-7	3332.1	8-3	1402.7		
2-5	2388.1	7-5	3332.1	9-3	974.2		
3-8	1402.7	6-7	3334.8	10-11	660.8		
3-9	974.2	7-6	3334.8				
		4-2	3259.0				
		5-2	2388.1				
		6-11	2230.8				
		7-11	2223.1				

Table 13
ATC Values with a 3000-MW Transaction from Zone 4 to Zone 6

REGION A ATC		REGION B ATC		REGION C ATC		REGION D ATC	
FROM-TO	MAX MW	FROM-TO	MAX MW	FROM-TO	MAX MW	FROM-TO	MAX MW
1-2	2179.3	4-5	2850.4	8-9	1472.8	11-6	1563.0
2-1	1961.0	5-4	3967.1	9-8	1461.6	11-7	2205.9
1-3	1646.6	4-6	547.5	8-10	1808.1	11-10	860.6
3-1	1875.8	6-4	6547.5	10-8	2045.3		
2-3	1247.2	4-7	1427.6	9-10	1071.7		
3-2	1497.1	7-4	4006.1	10-9	1222.9		
2-4	3510.3	5-7	2554.1	8-3	1532.0		
2-5	2193.6	7-5	3970.2	9-3	1062.6		
3-8	1273.3	6-7	5336.5	10-11	461.1		
3-9	885.7	7-6	888.0				
		4-2	3007.7				
		5-2	2582.6				
		6-11	2447.1				
		7-11	1660.6				

well. The ATC numbers with the 3000 MW zone 4 to zone 6 transaction are in Table 13. Every interface now has a directional asymmetry in ATC. ATC from zone 3 to zone 8, for example, has dropped from 1402.7 to 1273.3 MW because some of the power flowing from zone 4 to zone 6 flows on the path 4-2-3-8-10-11-6. The ATC in the opposite direction, from zone 8 to zone 3, has increased from 1402.7 to 1532.0 MW.

Consider the problem of a transmission user seeking to obtain transmission services for a transaction from zone 1 to zone 11 by using the information from Table 13 posted on the various regional OASIS web sites. There is no ATC value for zone 1 to zone 11 transactions because the regions with these zones are not directly connected and so did not calculate one.

In this situation the transmission user could calculate the ATC value, but that is what the ISO's are supposed to do. Instead, the transmission user will probably use a concept called a contract path. The contract path concept is used to make transactions easier to manage and to write contracts between suppliers, transmission owners, and customers. The

Table 14
"Connect the Dots" Path ATC

From	To	Link ATC (from Table 6.1)
1	2	2070.1 MW
2	4	3259.0 MW
4	6	3547.5 MW
6	11	2230.8 MW

Table 15
"Connect the Dots" Path ATC with an Existing Transaction of 3000 MW from Zone 4 to Zone 6

From	To	Link ATC (from Table 6.2)
1	2	2179.3 MW
2	4	3510.3 MW
4	5	2850.4 MW
5	7	2554.1 MW
7	11	1660.6 MW

contract path is the path over which the transaction is hypothetically supposed to flow.

This approach might be called the "connect the dots" method since the path is found by connecting zones (or ATC reporting points) along a path from the starting point to the receiving point for the transaction. If one draws a diagram with zones as circles and interfaces as lines, then the path is found by connecting them together, just like a child's picture is drawn by connecting numbered dots. One example contract path from zone 1 to zone 11 might be 1-2-4-6-11.

The transfer capacity of the contract path is obviously the lowest ATC on any of the links of the path. For the example path, the ATC values from Table 12 (no prior transactions) are shown in Table 14.

Since the minimum ATC along this path is 2070.1 MW, the transmission user could schedule a transaction of 2070.1 MW from zone 1 to zone 11. Recall, however, that the contingency limited ATC from zone 1 to zone 11 is actually 1608.5 MW, and the steady-state ATC is 2070.8 MW. If the 2070.1-MW transaction were imposed, the flow on the interface from zone 10 to zone 11 will be within a fraction of a percent of its maximum of 500 MW. If one circuit in the zone 10 to zone 11 interface is lost the remaining circuit will overload to 141% of its rating of 250 MW, which is unacceptable. The security of the power system is jeopardized. Using the "connect the dots" or "contract path" method, the capability of the transmission system to carry a transaction from zone 1 to zone 11 has been overestimated by 29%. The only way to avoid this security risk is to reduce the transaction from 1 to 11 to its safe maximum transaction value of 1608.5 MW. However, the value of 1608.5 MW is not calculated by the regions nor is it posted on the OASIS web pages.

This situation is even worse for the case with a 3000 MW transaction in place from zone 4 to zone 6. For the contract path 1-2-4-5-7-11, the "connect the dots" approach finds the link ATC's shown in Table 15.

The contract path ATC is 1660.6 MW. This is 61% above the actual ATC of 1020.7 MW with the 3000-MW transaction from zone 4 to zone 6 in place. If this transaction were in place at 1660.6 MW and a single circuit outage on the zone 4 to zone 6 interface were to occur, there would be large overloads on the remaining circuits in 4 to 6, as well as on the 6 to 7 interface. Further, if a circuit in the 10 to 11 interface were lost it would suffer a 46% overload on the remaining circuit in 10 to 11.

> Using the "connect the dots" approach to estimate ATC for transactions spanning several regions can grossly overestimate the actual ATC and can, if allowed to go unchallenged, result in serious system security problems.

Even within regions, the contract path approach can cause problems. For example, from Table 12, the ATC from zone 9 to zone 10 is 1147.3 MW, but the lowest ATC on the path 9-8-10 is 1467.2 MW. A 1467.2-MW transaction from 9–10 with transmission services reserved on the path 9-8-10 would result in contingency overloads on the transmission lines from 9 to 10. In this case, at least Region C would have the opportunity to prevent this problem by rapid recalculation of ATC. If ATC is recalculated after the 9–8 part of the path is reserved and before the 8–10 part, the ATC from zone 10 to zone 8 is only 1045.3 MW, a value that preserves system security.

In theory, the same process should prevent insecure region-spanning transactions. In practice, ATC is not recalculated for every reservation and information about reservations on interfaces not in a region does not always get to regions it affects. If both of these conditions were true, then insecure transactions would be prevented, but the process of making transmission service reservations would be cumbersome and inefficient. The user would have to start with a given value and make link reservations until ATC on the remaining links in the path was too low, and then lower the value and modify the reservations, or, if the value was satisfactory, go through and try a higher value.

The result of implementation of the regional ATC/OASIS system has been that ISO's often have to curtail reserved transmission services when actual operation makes it clear that the transmission system flows are insecure. In some cases flow patterns have surprised operators. So far they have been successful in maintaining reliable operation. However, the potential for an outage occurring when the transmission system is not capable of sustaining it is a serious security concern.

F. Transaction Management System (TMS)

In response to the problems of regional ATC, a more general methodology has been proposed by NERC. It dispenses with contract paths, working instead with the specific start and end points of a transaction. It uses a calculation tool called the interchange distribution calculator (IDC). IDC uses a linear, dc power flow model of the entire U.S. power grid, and it can quickly calculate the impact of any proposed transaction on the transmission facilities in the grid. PTDF's are the basis of the IDC model. IDC is incorporated into the TMS, now being deployed. TMS also incorporates a database and data-entry system. It requires all transmission users to enter information about transactions into a tagging system, then uses IDC to calculate the impact of the transaction and tells the prospective transmission user whether the transaction will violate security limits. In addition, NERC has developed a standard means for reducing the loading on transmission lines in emergencies known as transmission-line loading relief (TLR), which is also based on the sensitivities calculated by the IDC.

According to [8] the five functions of an open access market interface are:

1) reservation of transmission services;
2) procurement of ancillary services;
3) scheduling of energy interchange transactions crossing regional/provider boundaries;
4) a streamlined process for integration of next hour business, including transmission reservation, ancillary services, and energy scheduling;
5) curtailment notification;

The TMS system is made up of three main applications:

1) transaction information system (TIS);
2) IDC;
3) TLR.

The TIS application provides a means to enter, update, modify, and view transaction data. The transaction data include tagging [9] identifying information such as:

1) supplier or generation source control area identifier;
2) entity initiating the transaction;
3) unique transaction identifier;
4) purchaser or load control area.

Along with this data, the TMS database must keep information on the transaction approval status.

The IDC calculation application consists of a means of entering the status of major transmission facilities and then building a network model for the entire continental US and then calculating PTDF and LODF factors as outlined in Sections III-C and III-D.

The TLR procedure consists of identifying those transmission facilities that are overloaded and those transactions now in place which have the greatest influence on those facilities. The usual means of relieving the overload is to curtail transactions in a reverse priority order. First nonfirm transactions are curtailed in a last-in-first-out (LIFO) sequence. If this does not bring the necessary relief in transmission flow, the firm transactions are curtailed, and so on if additional priority classes exist.

Finally, the mechanism for accepting a transaction consists of multiplying a proposed transaction amount times the PTDF for each monitored facility (called a "flowgate," similar to the interfaces discussed in the example), adding the increment of flow determined in this way to the scheduled flow on the flowgate and testing this against the flowgate limit. If the test is failed the transaction is not allowed. A second step will add the transaction to the network and use the LODF and PTDF's for a fixed set of contingency cases to test the flowgate flow under single outage conditions, refusing any transactions which would cause severe first contingency overloads. Since the TMS has a global view of the power system, the regional problems of ATC/OASIS are corrected.

At the present time the TMS is going through the process of development of detailed specifications. The complete implementation is expected to take two years.

G. Potential TMS Problems

The use of a linear model for TMS calculations is likely to draw criticism from power engineering researchers because of the inaccuracies associated with off-nominal voltages, reactive power, lack of consideration of other power system controls, and the general nonlinearities of the power system. Although valid, this criticism addresses what are really minor issues. TMS seems likely to do a much better job of maintaining power system security and reliability than ATC/OASIS, at the cost of national centralization of transmission security.

However, there are two major objectives in congestion management. The first is maintaining security and reliability, and the second is market efficiency. TMS appears to be a technical solution to the technical problem of power system security devised without consideration of market efficiency. Unlike the OPF approach discussed in Section IV and the price area approach of Section V, TMS has only a weak link with the energy market. The initial priority used for transaction cancellation has some coupling to economics, in that firm transactions, for example, pay more for transmission services and therefore probably represent more beneficial transactions, but the subsequent LIFO transaction cancellation policy gives benefits to those who reserve early, rather than giving equal opportunity to all users as close to the time of use as possible, and it is completely insensitive to energy market efficiency issues. It is interesting to note that market efficiency is not one of the NERC defined functions of an open access market interface.

Without a coherent connection to market efficiency issues, TMS may not be a long term satisfactory solution to the U.S. transmission management problem.

VII. Strengths and Flaws

Each of the congestion management techniques discussed above has its strengths and its flaws. The set of techniques can be divided into deterrent techniques, which attempt to schedule generation prior to operation in such a way as to avoid congestion, and corrective techniques, which control generation at the point of real time operation to prevent congestion. Deterrent techniques might be called *ex ante*, since they are employed prior to operation, and corrective techniques might be termed *ex post*, since they are employed after congestion, or a trend toward congestion, is noted in the system.

Ex ante congestion management cannot by itself guarantee real-time reliability and security. Loads will vary from predicted values, lines and generators will experience unplanned outages, and generators will deviate from scheduled power outputs. Thus, every system must have *ex post* congestion management to accommodate real time variations in power system operation. While *ex ante* congestion management is not required for security, it can ease the burden on real time decision making and provide economic or organizational benefits.

Generation and load tariffs, and fixed transmission tariffs, have the least immediate effect of the *ex ante* congestion management techniques. By charging generators higher tariffs and loads lower tariffs in areas where excess generation creates congestion, and *vice versa*, or by charging higher tariffs on transmission lines that experience congestion than on those that do not, the tariff designer, usually the regulator but sometimes the system operator or transmission owner, is attempting to provide economic incentives for new generation and load to locate in areas where they do not cause congestion. The qualitative effect of such tariffs is clearly beneficial, but there is no analytical method of determining what these tariffs should be. Swedish tariffs are linear with latitude, which is clearly an approximation. Tariffs in the United Kingdom have been calculated using a transportation model, another approximation. The problem is associated with the linkage between new generation and new transmission. Incorrect tariffs can deter generation that should be constructed, along with associated new transmission, to improve the social welfare of the power system.

The first version of congestion management by *ex ante* transaction scheduling as practiced in the United States, regional ATC/OASIS, has shown weaknesses in maintaining system security and reliability due to the mismatch between its *de facto* contract path model and the actual performance of the transmission system. There have been no major blackouts clearly associated with transactions, although there is an understandable tendency to include uncontrolled flows in the aggravating factors of some events. However, the transaction cancellation mechanism has had to be employed with unsatisfactory frequency, operators have had to pay close attention to long range transactions in the networked system and have concerns about their visibility, and NERC has moved to replace OASIS with TMS.

TMS itself seems likely to do a better job of deterring congestion by not approving transactions that are likely to cause congestion problems. It should limit the number of transactions that have to be cancelled in real time and minimize transaction-related surprises for power system operators, addressing the immediate technical concerns of the OASIS system. However, the transaction cancellation mechanism is simply ignorant of its impact on the economic efficiency of the overall power system. In the long run, the failure to attend to the economic consequences of transmission management is likely to result in further revision or complete replacement of TMS.

Other congestion management techniques operate on the injections of the power system, that is, on a generator power output or a load power consumption considered by itself, instead of the paired generation and load comprising a transaction. OASIS and TMS operate on transactions at least in part for historical reasons. Transactions were the mechanism by which utilities exchanged electric energy prior to deregulation. However, transactions are inconsistent with electric energy exchanges or spot markets where there is not necessarily a one to one relationship between the energy buyer and seller. Such exchanges are economically desirable. It is interesting to note that any given set of transactions can be expressed as a unique set of corresponding injections, while a given set of injections may be expressed by many different sets of transactions. Injections appear to be the more fundamental way of addressing congestion management issues.

The price area congestion management system found in the Nord Pool area and in California is an effective *ex ante* deterrent. Relatively small corrections are necessary in real time to maintain transmission system security and reliability. The method is embedded in the day ahead spot market and allows market economics to operate within a price area unhindered by technical constraints. This may reduce opportunities for strategic bidder behavior associated with congestion, making the market more robust. It does require a centralized market but permits regional operation. In Nord Pool, the market now spans three countries, each with its own system operator. This is made feasible by ensuring that system operator boundaries are also price area boundaries. The centralized part of the system deals mostly with economics—price and quantity bids—with limited and transparent technical limitations—the price area boundaries and transfer limits—while the regional system operators deal with local and real time corrections.

The price area system of course requires an *ex post* correction mechanism, but the major limitation is that it is accurate only for radial transmission systems, ones without loop flows. Neither Nord Pool nor California has a truly radial transmission system, but in both cases the system is near-radial and the inaccuracies are small. For strongly networked systems like those in the central and eastern United States and Europe, loop flow effects may be too significant to permit the employment of price areas.

Price area congestion management results in income to the market operator, which is redirected to the system operator in both Nord Pool and California. There is clearly a concern when the operator that manages congestion receives more income when congestion increases. Public regulation of the operator removes the major financial incentive to create congestion, but side effects may remain, for example, if congestion income appears in the budget of a unit manager or when congestion income is traded off against other sources of revenue during the regulatory process.

The buyback method provides effective real-time control of congestion and can use the same generation adjustment mechanism that control areas require for other purposes such as load/frequency control. The Nord Pool and California payment method, which effectively changes the market price based on adjustment needs, is clearly superior to the U.K. payment method. The latter pays similar prices for operating generators above their uncongested schedules, but it pays generators the difference between bid price and market price to operate below schedule, where in Nord Pool a price taking generator would pay to be reduced. The system operator's net payment for buyback congestion management provides a financial incentive to operate the network to minimize congestion, because less congestion means a lower payment from what is usually a regulated income.

OPF is the most complex but arguably the most accurate and effective congestion management method for strongly networked (meshed) transmission systems. It explicitly trades off market economics with technical constraints. A full optimal power flow can include the effects of other controls such as reactive power, transformer taps and phase shifters that can affect congestion. A mechanism for accommodating bilateral transactions eases some concerns about mandatory participation markets.

Perhaps the strongest concern about OPF solutions is the lack of transparency in the solution process. When every participant has a different market price, participants are naturally interested in obtaining a clear understanding of the reason for their particular price. When a large-scale OPF is run, such reasons are seldom clear, and the need to trust the program output is unsatisfying.

Other congestion management methods are more transparent. Price area congestion management supplies a single market clearing price that is applicable to every bidder in a given price area. Buyback provides a single area-based adjustment price. ATC transaction cancellation on a last-in first-out basis, while criticized for other reasons, has the virtue of clarity. Closer inspection of these techniques will find lack of transparency in the designation of price areas and calculation of transfer limits. However, these techniques may be said to have first-order transparency at the direct interface with market participants that OPF lacks.

The profusion of different local marginal prices that appears when any line in a networked system is congested represents another form of OPF transparency problem. Market participants would prefer to have one market price, or at least one price in a reasonably large region. This allows exchanges or trading hubs to operate in an environment where everyone gets the same price signal. Averaging different local marginal prices to obtain a regional price, which is done by several ISO's, is not really a satisfactory solution when actual payments are based on a different price, yet payments based on average local marginal price are also unsatisfactory.

As with price area congestion management, OPF with local marginal prices results in an increase in income to the system operator when congestion increases, and consequent concerns about the effects on congestion of this financial incentive.

Market participants may obtain market power, and consequently create market inefficiency, by strategic bidding designed to take advantage of the characteristics of a specific OPF implementation. This would be market power beyond that created by lack of market diversity—a small number of bidders—or by congestion. Both of the latter sources of market power will operate no matter what form of congestion management is employed. In general, when bidders must supply technical information that serves as input to the optimization algorithm, that information will be viewed as a potential source of market power and manipulated accordingly. In this respect, OPF is probably somewhat less robust than the price area system, where market resolution is purely a function of price and quantity bids within price areas.

Just as regional ATC/OASIS is weak in its ability to manage long distance transactions, regional OPF solutions will not effectively control the interconnected transmission system. The obvious solution is a central system operator with a centralized OPF algorithm that operates a national *ex post* energy market. Quite apart from the political and organizational issues associated with establishing such a system, there would be a number of issues specific to the OPF algorithm. Run time with a huge problem size and real-time performance requirements would be the first, but maintenance of the database, including long term changes, outages, real-time data acquisition and participant bids would be a constant concern. The robustness of the algorithm would require careful attention, especially when the transmission system is highly stressed. The reliability of the computer system that implements the algorithm, and of all of the communication links, would also be a concern.

The national visibility and centralized control required by the TMS and OPF congestion management methods, and to a lesser extent by the price area method, to maintain security and reliability, is an uncomfortable departure from previous experience for U.S. utilities and may generate similar concerns as utilities from different countries enter one marketplace in Europe. Decentralized autonomous cooperative control has been the historical pattern in the utility industry, with each utility self-sufficient in its own control area, cooperating closely with its near neighbors, and less aware of events further from its locale. However, TMS is a step in a trend towards centralization driven by the interdependence of the interconnected grid which started (with GAPP) before deregulation, and centralized OPF may be the next step forward.

Reliance on a centralized market and control center is not comfortable for many in the power engineering community, but it may be the best option presently available for networked transmission systems. Until a regional autonomous method of congestion management is developed which is analogous to the formulation of AGC [10] that enabled extensive interconnection of utilities, the trend towards centralization is likely to continue.

VIII. Future Needs and How to Get There

Four possible paths to the future of transmission management suggest themselves: Transaction based, OPF based, price area, and distributed. Each needs research to move along the path to better tradeoffs between system reliability and market economics.

The transaction-based approach must be changed to take its effect on market efficiency into account, and perhaps to allow for spot markets with multiple, unpaired bidders in its operating mechanism. Improvements in the ATC calculation algorithm that take the nonlinearities of the power system into account can be expected to improve accuracy at the expense of computation time and complexity.

For OPF-based approaches, the immediate challenge is to implement the continent-wide OPF mechanisms that will be needed to cope with networked systems that accept long distance transactions. Continent-wide OPF faces some significant engineering challenges. Run time for systems with tens of thousands of buses and real time performance requirements merits attention. The robustness, data maintenance, communications, and reliability issues raised in Section VI will have to be addressed. Given the necessary legal, administrative, and organizational support, these challenges should yield to good engineering.

A somewhat different challenge is to determine whether a centralized optimization algorithm such as OPF, even with participant bidding, is economically as effective as simpler market mechanisms such as those used in price areas. If the use of centralized optimization creates excessive market inefficiency, then alternative structures that enable more efficient markets must be found. What these structures will be is not clear.

Price area approaches, while less technically complex than OPF approaches, still have challenges. One is to determine when a transmission system is sufficiently radial to employ price areas instead of OPF. Another is to provide an analytical method of determining where the boundaries should be drawn between price areas, and how inter-area transfer limits should be set. Price areas must also face questions about their economic efficiency, in comparison with centralized OPF.

The path to decentralized transmission management is less clear. Some sort of autonomous or hierarchical cooperative transmission management algorithm is needed that provides for robust and secure operation of the transmission system and also optimizes market efficiency in the presence of bilateral transactions that span a number of autonomous regions in a networked system. No immediate answer presents itself to the authors!

Finally, the discussion of congestion deterrence with geographically variable tariffs points first to the need for an analytical method of setting these tariffs, and second to the much larger problem of transmission reinforcement (planning and construction of new transmission facilities). The latter has not been addressed in this paper. Clearly there is a tradeoff to be made between the social costs of congestion and the costs of transmission construction, but algorithms for determining this are not yet well established.

Transmission management poses a wide range of problems for both the power engineer and the economist, ranging from pragmatic issues of algorithm implementation to entire new mechanisms for distributed transmission management. The problems are likely to be best solved by a close cooperation among experts in the two disciplines.

IX. Conclusion

This paper has discussed congestion-management issues in some detail, describing the practice and some of the analytical background for each of the major techniques now in use world wide, analyzing strengths and weakness in the approaches, and exploring future directions and needs connected with this vital problem.

The paper has not addressed other important aspects of transmission management. For example, the important long-term problem of transmission reinforcement—deciding when and where to build new transmission facilities—has been dealt with only peripherally. Losses have been neglected throughout the discussion. Proper treatment of losses should improve market efficiency, but the discussion would be a paper in itself. The same applies to the provision of reactive or voltage support for transactions or for the system, and to other ancillary services that may be needed, or at least defined, to support the transmission system. The setting of tariffs has only been addressed in connection with congestion. Loss-related tariffs and fair tariffing to cover system operating costs are also important issues in transmission management. Time and space have prevented a complete exploration of these issues.

Utilities cannot wait for a complete theoretical understanding or for the optimal solution of their problems. They have to put feasible solutions in place and operate the transmission system pragmatically. The range of solutions this imperative creates has some successes, and some less successful approaches. Improved understanding of transmission management issues will lead to improved solutions in a problem space that is still new to both power engineering and economics.

Appendix A
Proof of (IV.2)

Consider the OPF formulated as

$$\min f(\mathbf{P_G}, \mathbf{P_D}) \tag{A.1}$$

subject to dc power flow equations

$$\mathbf{B_x}\boldsymbol{\theta} - \mathbf{P_G} + \mathbf{P_D} = \mathbf{0} \tag{A.2}$$

and power flow constraints

$$\mathbf{P_T} - \mathbf{P_T^{\max}} \le \mathbf{0}. \tag{A.3}$$

The objective function (A.1) can be minimization of generation costs in the constant load case or maximization of social welfare by minimizing generation costs minus load worths in the elastic load case. The form is irrelevant to the proof so a generic function f is used. $\mathbf{P_G}$ and $\mathbf{P_D}$ are vectors of generation and load at each zone, respectively. Constraint (A.2) is a compact form of (IV.5). $\boldsymbol{\theta}$ is the vector of zone angles.

In constraint (A.3), $\mathbf{P_T}$ is a vector of interface power flows (transfers). For the interface from zone i to zone j, both P_{ij} and P_{ji} appear in $\mathbf{P_T}$. One is the negative of the other. Clearly only the positive one can be binding. $\mathbf{P_T^{\max}}$ is the vector of flow limits. Transfer can be expressed as a function of phase angles

$$\mathbf{P_T} = \mathbf{A}\boldsymbol{\theta} \tag{A.4}$$

from (III.1) in matrix form

$$\begin{bmatrix} P_{ij} \\ P_{rs} \\ \vdots \end{bmatrix} = \begin{bmatrix} \frac{1}{x_{ij}} & & \\ & \frac{1}{x_{rs}} & \\ & & \ddots \end{bmatrix} \begin{bmatrix} \cdots & 1 & -1 & & & \\ & & & 1 & -1 & \\ & & & & & \ddots \end{bmatrix} \begin{bmatrix} \theta_1 \\ \vdots \\ \theta_n \end{bmatrix} \quad \text{(A.5)}$$

where

$$\mathbf{A} = \begin{bmatrix} \frac{1}{x_{ij}} & & \\ & \frac{1}{x_{rs}} & \\ & & \ddots \end{bmatrix} \begin{bmatrix} \cdots & 1 & -1 & & & \\ & & & 1 & -1 & \\ & & & & & \ddots \end{bmatrix} \quad \text{(A.6)}$$

and

$$\mathbf{P_T} = \begin{bmatrix} P_{T_1} \\ \vdots \\ P_{T_2} \end{bmatrix} = \begin{bmatrix} P_{ij} \\ P_{rs} \\ \vdots \end{bmatrix}. \quad \text{(A.7)}$$

Then (A.3) can be written

$$\mathbf{A}\boldsymbol{\theta} - \mathbf{P}_\mathbf{T}^{\max} \leq \mathbf{0}. \quad \text{(A.8)}$$

The Lagrangian for this problem is

$$\begin{aligned} L = f(\mathbf{P_G}, \mathbf{P_D}) + \boldsymbol{\pi}^t [\mathbf{B_x}\boldsymbol{\theta} - \mathbf{P_G} + \mathbf{P_D}] \\ + \boldsymbol{\lambda}^t [\mathbf{A}\boldsymbol{\theta} - \mathbf{P}_\mathbf{T}^{\max}] \end{aligned} \quad \text{(A.9)}$$

where $\boldsymbol{\pi}$ and $\boldsymbol{\lambda}$ are vectors of Lagrange multipliers. At optimality

$$\frac{\partial L}{\partial \boldsymbol{\theta}} = 0 \quad \text{(A.10)}$$

taking the derivative

$$\boldsymbol{\pi}^t \mathbf{B_x} + \boldsymbol{\lambda}^t \mathbf{A} = 0 \quad \text{(A.11)}$$

multiplying by $\boldsymbol{\theta}$

$$\boldsymbol{\pi}^t \mathbf{B_x}\boldsymbol{\theta} + \boldsymbol{\lambda}^t \mathbf{A}\boldsymbol{\theta} = 0 \quad \text{(A.12)}$$

applying (A.2) and (A.4)

$$\boldsymbol{\pi}^t [\mathbf{P_G} - \mathbf{P_D}] + \boldsymbol{\lambda}^t \mathbf{P_T} = 0 \quad \text{(A.13)}$$

which can be rewritten and rearranged to

$$\sum_{\text{zones } i} \pi_i P_{D_i} = \sum_{\text{zones } i} \pi_i P_{G_i} + \sum_{\text{constraints } j} \lambda_j P_{T_j}. \quad \text{(A.14)}$$

From the complementarity slackness condition of the Kuhn–Tucker conditions at optimality, if flow constraint j is not binding, its multiplier $\lambda_j = 0$. If flow constraint j is binding, its multiplier is positive, $\lambda_j > 0$ [38]. As discussed above, if the constraint is binding and the flow is positive, $P_{T_j} > 0$. Thus if any constraint is binding

$$\sum \lambda_j P_{T_j} > 0 \quad \text{(A.15)}$$

so

$$\sum \pi_i P_{D_i} > \sum \pi_i P_{G_i} \quad \text{Q.E.D.} \quad \text{(A.16)}$$

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