FLOWGATE RIGHTS AND WRONGS

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There have been many attempts to define transmission rights in terms of the flows over individual lines. The flowgate model is one approach offered as an alternative to efficient pricing in a coordinated dispatch with point-to-point financial transmission rights. An examination of the assumptions of flowgate rights identifies a number of flowgate wrongs. To the extent that the wrongs are minor, there should be no significant market failure and the commercial market participants could innovate to capture the benefits of flowgate rights. To the extent the wrongs are significant, the system operator should avoid modifying its basic design to accommodate and socialize the costs of the errors.

INTRODUCTION

The Federal Energy Regulatory Commission (FERC) outlined a number of responsibilities in its order on the design of Regional Transmission Organizations (RTO).[2] Among other things, the RTOs must provide access to a real-time electricity balancing market and market mechanisms for managing transmission congestion. Inevitably, these two functions interact with each other to a degree that one cannot be designed or operated without some view of how the other would operate. A working integrated market for balancing and congestion is available in the form illustrated by the market design built on locational marginal pricing and financial transmission rights.[3]

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[2] Federal Energy Regulatory Commission, "Regional Transmission Organizations," Order No. 2000, Docket No. RM99-2-000, Washington DC, December 20, 1999.

[3] For a further discussion, see William W. Hogan, "Regional Transmission Organizations:

The locational pricing and financial transmission rights model integrates spot market electricity prices with a point-to-point definition of transmission rights, avoiding the requirement for explicit definition of transmission rights in terms of the flows on the network. Alternative approaches to congestion management, and even electricity balancing, have been suggested that define transmission rights explicitly, to one degree or another, in terms of the actual flows in the network. Intuitively appealing, these flow or link-based methods seem like a natural way to assign property rights in the transmission network. However, experience with the contract path model, the original such link-based method, has demonstrated that some commercial simplifications of the complex network interactions can be too simple to work in the context of a competitive electricity market.[4]

The migration of the flow-based transmission rights concept has moved from the contract-path model, to the zone-to-zone contract path model, through to various incarnations in the so-called flowgate model proposed in several venues and for different purposes. A distinctive characteristic of the flowgate models is the common recognition that power will flow over multiple parallel paths and transmission rights are defined accordingly. However, questions remain as to how these rights would relate to or affect use of the grid, and how they would interact with an efficient balancing market. The purpose here is to discuss these interactions and the effect of the assumptions and simplifications of a version of the flowgate rights approach. This suggests a view of what could or should be done by the RTO and what could and should be left to the commercial market.

An overview of a common electricity market model provides a framework for reviewing the locational marginal pricing and financial transmission rights approach. The same framework highlights key simplifying assumptions in a generic description of the flowgate rights. An analysis of these assumptions identifies a number of flowgate wrongs. To the extent that the wrongs are minor, then there should be no significant market failure and the commercial market participants could innovate to capture the benefits of flowgate rights. To the extent the wrongs are significant, the RTO should avoid modifying its basic design to accommodate and socialize the costs of the errors. Either way, the RTO would adopt the locational marginal pricing and financial transmission rights approach. This would allow for a straightforward integration of competitive commercial services providing the services promised in the flowgate design.

ELECTRIC MARKET MODEL

For the sake of this discussion, the basic market model can be reduced to a few key elements. It is convenient to begin with a market equilibrium that is equivalent to an economic dispatch formulation with full optimization. For this purpose, we define a model of the power system and a bid-based, security-constrained, economic dispatch.

Millennium Order on Designing Market Institutions for Electric Network Systems," Center for Business and Government, Harvard University, May 2000.

[4] For another example, see the paper with the clever title, S. Stoft, "Transmisison Rights and Wrongs," Electricity Journal, Vol. 10, No. 8, October 1997, pp. 91-95.

Let:

g	the vector of real power generation at the buses,
d	the vector of real power loads at the buses,
y	the vector of net loads at the buses, equal to demand minus generation at each bus, $y=d-g$,
x	the vector of transmission variables such as transformer settings, reactive power inputs and voltages,
$B(d)$	the bid-based benefit function for loads,
$C(g)$	the bid-based cost function for generation,
$K(x,y)$	the vector of constraints in the transmission grid.

The corresponding bid-based, security-constrained, economic dispatch problem can be defined as:

$$\begin{aligned}&\underset{d,g,x,y}{Max} \quad B(d)-C(g)\\&\textit{subject to}\\&d-g=y\\&K(x,y)\leq 0.\end{aligned} \tag{1}$$

To focus the later discussion, the system balance conditions and transmission limits all are subsumed under the set of system constraints here represented in terms of the net loads and transmission variables. In principle, the set of constraints includes all possible contingency limitations recognized by the system operator. Hence, there could be a very large number of elements in the vector of constraints summarized in $K(x,y)$. For clarity, the constraints are expressed in terms of net loads, but there could be circumstances in which load and generation have different effects, but that is not central to the issues here.

The treatment of the transmission variables in x as under the control of the system operator simplifies the discussion and provides a reasonable representation of the current markets. In particular, transmission customers are not charged the marginal opportunity costs for reactive power and such costs are treated separately as in an uplift payment. Further, it may be that changing market conditions affect the degree to which the system operator can adjust reactive power loads and other transmission variables, which would affect the definition of the real power constraints.

A more elaborate formulation would unpack the details of the cost and benefit functions to recognize individual units, output capacity constraints, and so on. However, to focus attention on the transmission issues, these generation and load representations are summarized under continuously differentiable system benefit and cost functions. As long as we remember that these are system definitions (as opposed to the marginal cost of each individual plant) the basic arguments apply.

Under the usual assumptions about the existence of a solution (x^*,y^*,d^*,g^*), the necessary conditions for optimality indicate that the shadow price vector p for the net load equations defines the locational marginal prices (LMP) at the buses and we have:

$$p = \nabla B(d^*) = \nabla C(g^*)\,. \tag{2}$$

In other words, the locational price is equal to the marginal benefit to the loads, which is in turn equal to the marginal cost of system generation. Furthermore, if we define μ as the shadow price for the transmission constraints, then we see that this vector of locational prices is related to the Jacobian of the transmission constraints according to:

$$p = \nabla K_y^t(x^*, y^*)\mu. \tag{3}$$

The matrix $\nabla K_y(x^*,y^*)$ is composed of the transpose of the gradients of the individual transmission constraints with respect to changes in the real power net loads. The main elements of this matrix are sometimes referred to as the "distribution" or "shift" factors, meaning the change in the constraint induced by an increment of net load at a bus with the corresponding balanced decrement of net load at a reference bus. These shift factors are essentially the same as the power transfer distribution factors (PTDF) or the PTDFs can be constructed from the shift factors. Hence, the LMP price vector p is a linear combination of the distribution factors times the constraint multipliers or shadow prices, all evaluated at the optimal dispatch solution.

A corresponding definition of a competitive electricity market equilibrium would have the loads and generators acting as price takers who face p and maximize their own benefits and profits to obtain $y^*=d^*-g^*$. The corresponding definition of the problem for the transmission provider would be that given the prices in p, the equilibrium solution y^* is also a solution for the transmission problem:

$$\begin{aligned} &\underset{x,y}{Max} \quad p^t y \\ &subject\ to \\ &K(x,y) \le 0. \end{aligned} \tag{4}$$

With a well-behaved problem, the general formulations of economic dispatch and market equilibrium are equivalent. And if the problem is not behaved well enough so that there is such a competitive market equilibrium, then the difficulties would go beyond those discussed here.

FINANCIAL TRANSMISSION RIGHTS

The basic locational marginal price model with some form of financial transmission rights builds on the structure of this economic model of the electricity system as summarized in (1) through (4). The details can be more elaborate, but the essential ingredients are generally the same.

First, there is the spot market that provides balancing services. Market participants provide either schedules between locations, bids to buy and sell power at locations, or both. The combination of schedules and bids produces an economic (re)dispatch problem of the form of (1). The solution produces a set of inputs and outputs at every location along with the market clearing prices defined in p.

Market participants who have chosen to buy and sell through the spot market settle these transactions at the corresponding locational price. Those who have scheduled deliveries between locations pay the opportunity cost of transmission defined as the difference in the locational prices at the entry and exit locations.

The net collection by the transmission operator is $p^t y^*$. If no flow is a feasible solution, i.e., there exists some x such that $K(x,0) \leq 0$, then $p^t y^* \geq 0$. Any positive difference amounts to the rents collected by the system operator. In general, this includes the rents associated with the difference between marginal and average losses as well as the differences in location prices created by system congestion. To simplify the discussion here, ignore the loss component and interpret the rents as congestion rents.

The financial transmission right (FTR) provides a disbursement of the congestion rents by defining a point-to-point contract to collect the difference in the locational prices.[5] These rights could be options (one-sided) or obligations as in forward contracts (two-sided). To illustrate the case of obligations, suppose that FTR t_i defines a vector of inputs and outputs, typically between locations. Hence, input of g_i at bus 1 and output of d_i at bus 59 would be the vector $t_i=(-g_i, 0, 0,\ldots, d_i, 0, \ldots)^t$. Then the FTR right pays the holder $p^t t_i = p_{59} d_i - p_1 g_i$. As usually applied, this is a balanced right, in the sense that $d_i = g_i$. However, there is no reason in principle why individual FTRs need to be balanced as long as there is an aggregate balance. The FTR is point-to-point in the sense that there need be no direct line between buses 1 and 59. In the case of a bilateral schedule to deliver g MW of power between bus 1 and 59, the transmission charge would be $p_{59}g - p_1 g$. Hence, an FTR for g MW between the two locations would provide an exact hedge against the differential in prices. There would be no need to define or be concerned with the path the power takes through the network as all the network interactions would be internalized in the prices.

Suppose that the vector $t=\Sigma t_i$ defines the aggregate set of transmission FTRs defined as obligations. Then if there is an x such that $K(x,t) \leq 0$, the elements in the set of FTRs are simultaneously feasible. For any set of simultaneously feasible FTRs and any competitive market equilibrium as defined above, we always have $p^t y^* \geq p^t t$. Hence, the congestion rents collected in the actual dispatch are always sufficient to pay out the compensation for the FTRs. This is referred to as "revenue adequacy." In general, there may be excess revenue and there will be a portion of the congestion rental that is disbursed in a number of ways, such as to reduce transmission access charges.

The FTRs provide long-term transmission rights that can be different from the actual dispatch of the system. Although it is impossible to maintain a perfect match of long-term rights and the actual dispatch, it is possible to guarantee the financial payments to the FTR holders as long as the outstanding FTRs continue to pass the simultaneous feasibility test. The initial allocation of FTRs could proceed in a number of ways,

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[5] Also known as Fixed Transmission Rights, Transmission Congestion Contracts and Financial Congestion Rights.

including through an auction of the rights conducted by the system operator. Periodic changes and reconfigurations of the rights could be arranged through similar auctions. New FTRs could be created by changing the system configuration, and the old rights could be preserved or sold for something better to maintain simultaneous feasibility.[6]

The FTRs allow for decentralized trading of ownership. Within the collection of rights, it is also possible to decompose and separate rights that are defined as obligations. In particular, rights to and from market hubs could be created out of any obligation between points. The single right between A and B is equivalent to two FTRs in the same amount, from A to the hub and from the hub to B. This supports a hub-and-spoke trading model.

The extension of FTRs to include options is possible, in exchange for some additional complications. For an obligation-type FTR, the payment is $p^t t_i$. This value could be negative. In this circumstance, the perfect hedge for a bilateral transaction would still obtain because the charge for using the system would also be negative in the same amount. However, there is a strong interest in defining rights not as obligations but as options. The option would define the payment as $Max(0,p^t t_i)$. Hence the holder would be compensated when there was a positive difference but not charged when there is a negative difference.

The complex interactions in the electric network include counterflows where, in effect, one transaction nets out the flows of another. An FTR obligation implies that the flow, or the corresponding payment, will always be available, and this allows for more transactions. By definition, this is not true for the FTR option. In effect, therefore, the single simultaneous feasibility test outlined above would be replaced by a requirement that all possible combinations of options would be feasible. This test is more difficult to conduct, and the resulting aggregate capacity of the grid would be reduced. Furthermore, the options would not decompose into the hub-and-spoke model in the same way as the obligations. An option between A and B is not the same as two options, one from A to the hub and another from the hub to B. Nonetheless, the options may be preferable for market participants. The availability of FTR auctions would produce added flexibility in combination with FTR obligations. In principle, it would be possible to define and use both types of FTRs.[7]

Within this framework, the balancing and congestion management markets exploit a bid-based, security-constrained economic dispatch with voluntary participation by generators and loads. The corresponding prices are consistent with the competitive outcome and would reflect the marginal bid cost of meeting load at each location. Bilateral transmission schedules of great flexibility and market-responsiveness could be accommodated with the transmission usage price set consistently at the difference in the locational energy prices. There would be no bias between bilateral schedules and the

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[6] William W. Hogan, "Transmission Investment and Competitive Electricity Markets," Center for Business and Government, Harvard University, April 1998.

[7] For further details , see Scott M. Harvey, William W. Hogan, and Susan L. Pope, “Transmission Capacity Reservations and Transmission Congestion Contracts,” Center for Business and Government, Harvard University, June 6, 1996, (Revised March 8, 1997).

coordinated spot market. The market for ancillary service acquisition and pricing could be integrated simultaneously in the economic dispatch. Long-term financial transmission rights would be defined that would entitle the holder to the difference in locational prices.

The theory of the case is by now well supported by practical experience. The main ingredients exist in many parts of the world, and the combined package has been operating successfully in the Pennsylvania-New Jersey-Maryland Interconnection (PJM) for more than two years.[8] The same basic model has been adopted in New York,[9] and embraced as a reform in New England.[10] Likewise, the difficulties that arise when we do anything else are apparent in various experiments where putative simplifications produced predictable problems.[11]

FLOWGATE RIGHTS

The essential market ingredients outlined above include a coordinated spot market integrated with system operations to provide balancing services and congestion management. In principle, an alternative to central coordination would be a system of decentralized congestion management that used the same basic information as does the system operator but that could be handled directly by the market participants.

The most prominent recent example of such a decentralized congestion management model is the so-called "flowgate" approach. This is interesting as both a theoretical argument[12] and because it is the procedure embraced by NERC as a principal market alternative to its disruptive administrative Transmission Loading Relief (TLR) procedures.[13] The details can be complicated, but the basic idea is simple. The argument begins with the recognition that the contract path model is flawed. Power does not flow over a single path from source to sink, and it is this fact that causes the problems that lead to the need for TLR in the first place. If a single contract path is not good enough, perhaps many paths would be better. Since power flows along many parallel paths, there

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8 PJM Interconnection. L.L.C. For further details on the experience in PJM, see William W. Hogan, "GETTING THE PRICES RIGHT IN PJM. Analysis and Summary: April 1998 through March 1999, The First Anniversary of Full Locational Pricing," April 2, 1999, available through the author's web page; and the earlier discussion in the Electricity Journal, September 1998.

9 New York began operation under this market design in November 1999.

10 ISO New England, "Congestion Management System and a Multi-Settlement System for the New England Power Pool," FERC Docket EL00-62-000, ER00-2052-000, Washington DC, March 31, 2000.

11 William W. Hogan, "Regional Transmission Organizations: Millennium Order on Designing Market Institutions for Electric Network Systems," Center for Business and Government, Harvard University, May 2000, pp. 25-28, available from the author's web page.

12 Hung-po Chao and Stephen Peck, "A Market Mechanism for Electric Power Transmission," Journal of Regulatory Economics, Vol. 10, No. 1, 1996, pp. 25-59. Hung-po Chao and Stephen Peck, "An Institutional design for an Electricity Contract Market with Central Dispatch," The Energy Journal, Vol. 18, No. 1, 1997, pp. 85-111. Steven Stoft, "Congestion Pricing with Fewer Prices than Zones," Electricity Journal, Vol. 11, No. 4, May 1998, pp. 23-31.

13 Congestion Management Working Group of the NERC Market Interface Committee, "Comparison of System Redispatch Methods for Congestion Management," September 1999.

is a natural inclination to develop a new approach to transmission services that would identify the key links or “flowgates” over which the power may actually flow, and to define transmission rights according to the capacities at these flowgates. This is a tempting idea with analogies in markets for other commodities and echoes in the many electricity industry MW-mile proposals, rated-path methodologies, the General Agreement on Parallel Paths (GAPP), and related efforts that could go under the heading of transmission services built on link-based rights.

For any given total set of power injections and withdrawals, it is possible to compute the total flows across each line in the transmission network. Under certain simplifying assumptions, it would be possible further to decompose the flows on the lines and allocate an appropriate share of the flows to individual transactions that make up the total load. If we also knew the capacity on each line or groups of lines, then presumably it would be possible to match the flows against the capacities and define transmission services. Transmission users would be expected to obtain rights to use the lines, perhaps from the transmission line owner or from others who owned these capacity rights.

In principle, these rights on each line might be seen as supporting a decentralized market. Associated with each line would be a set of capacity allocations to (many) capacity right holders who trade with the (many) users of the system who must match their allocated flows with corresponding physical capacity rights. Within this framework there are at least two interesting objectives. First, that the trading rules should lead to an efficient market equilibrium for a short period; and second, that the allocated transmission capacity rights would be useful for supporting long-term transactions in the competitive market for geographically dispersed buyers and sellers of power.

As a theoretical matter, it is likely that the first objective could be met. Ignoring transaction costs and the question of timely convergence, there should be some system of tradable property rights that would be sought by users of the system, and in so doing would lead to an efficient short-run dispatch of the system. This would seem to be nothing more than an application of the principles of competitive markets with well-defined property rights and low transactions costs. There is a general belief that this short-run efficiency would be available in principle: "Efficient short-run prices are consistent with economic dispatch, and, in principle, short-run equilibrium in a competitive market would reproduce both these prices and the associated power flows."[14] The problem has always been with the natural definitions of the "physical" rights: these are cumbersome to trade and enforce. The property rights are hard to define, and the transaction costs of trading would not be low.

The second objective is perhaps more important. Presumably the allocated transmission capacity rights would extend over many short-run periods, for example, even only a few days, weeks or months of hourly dispatch periods.[15] Presumably a natural characteristic that would be expected of these physical rights would be that a

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[14] W. Hogan, Contract Networks for Electric Power Transmission," Journal of Regulatory Economics, Vol. 4, 1992, p. 214.

[15] This is apart from the problems encountered with changes of the grid capacity or configuration. Link-based rights have other substantial problems for dealing with system expansion.

seller of power with a known cost of power production could enter into an agreement with a distant buyer to deliver a known quantity of power at a fixed price, including the out-of-pocket cost for transmission using the transmission right. Many other contracts could be envisioned, but this minimal possibility would seem to be essential; and it is broadly taken for granted that this capability will exist in the open-access transmission regime. However, any approach that defines tradable physical capacity rights based on flows on individual lines faces obstacles that appear to make it impossible to meet this minimal test.

There are many proposals for such flowgate rights (FGR), and they differ in important details.[16] [17] [18] [19] [20] [21] However, there is a general market model at the core of these proposals. A sketch of this model provides the context for addressing a few critical assumptions of the flowgate approach. The principal simplification is to apply the DC-Load approximation to the model in (1) to simplify the representation of the transmission constraints.[22] In the terminology used above, the focus is on the constraints in $K(x,y)$. First, the assumption is that the constraints can be represented by a linear approximation relative to zero real power injections as in:

$$K(x,y) \approx K(x,0) + \nabla K_y(x,0)(y-0) \leq 0. \qquad (5)$$

In addition, the assumption is that transmission variables such as reactive power loading and various settings in x can be determined such that the linear approximation is constant, implying that we can ignore any dependence of the gradient on x. Furthermore, the constraints apply only to line flows or their linear combinations and the constraint limits are equal to the maximum flows. Hence, let $H = \nabla K_y(x,0)$ represent the matrix of system balance and power transfer distribution factors (PTDF) and b represent the bounds on maximum flows on the transmission lines. The combined assumptions suggest that we can modify (5) as in:

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16 WICF Path Allocation Task Force, "Allocation of Transmission Capacity Between Interacting Transmission Paths," Report to the RTA Board, October 12, 1999.

17 Congestion Management Working Group of the NERC Market Interface Committee, "Final Report on the NERC Market Redispatch Pilot," November 29, 1999, filed with FERC on December 1, 1999.

18 Ed Cazalet and Ralph Samuelson, "The Power Market: E-Commerce for All Electricity Products," Public Utilites Fortnightly, February 1, 2000.

19 Hung-po Chao, Stephen Peck, Shmuel Oren, and Robert Wilson, " Flow-based Transmission Rights and Congestion Management," August 18, 2000 (forthcoming Electricity Journal).

20 California ISO, "Congestion Management Reform Recommendation," July 11, 2000.

21 Tabors Caramanis & Associates, "Real Flow A Preliminary Proposal for a Flow-based Congestion Management System," Cambridge, MA, July 18, 2000.

22 F. C. Schweppe, M. C. Caramanis, R. D. Tabors, and R.E. Bohn, Spot Pricing of Electricity, Kluwer Academic Publishers, Norwell, MA, 1988.

$$\begin{aligned}&K(x,y) \approx K(x,0) + \nabla K_y(x,0)(y-0) = -b + Hy \leq 0,\\&or\\&Hy \leq b.\end{aligned} \tag{6}$$

With these assumptions and substitutions, the revised form of the basic market model in (1) becomes:

$$\begin{aligned}&\underset{d,g,x,y}{Max} \quad B(d) - C(g)\\&subject\ to\\&d - g = y\\&Hy \leq b.\end{aligned} \tag{7}$$

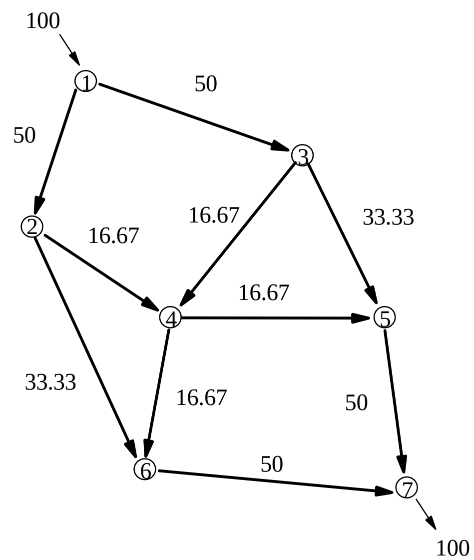
The key to the definition of flowgate rights is to exploit the linearity of the constraints. In particular, the idea is that the quantity of maximum available flow on the respective lines represented by b could be divided into individual capacity rights that could be sold and traded in the market place. The distribution factor matrix in H would identify how many different rights on each flowgate would be associated with any point-to-point transaction. Each market participant could then acquire the appropriate number of rights on each flowgate and, because of linearity, the rights acquired would add up to no more than the total available.

A stylized example illustrates the basic idea and the power of the simplifying assumptions. Consider the seven bus network in the accompanying figure. The ten lines are connected as shown, and each line is assumed to have the same impedance. There is nothing important about this assumption other than it simplifies the reader's check of the arithmetic. In general there would be different line impedances and this would affect the resulting power flows. The figure shows the flows from bus 1 to bus 7 and the implied table of distribution factors. Hence, if we send 100 MW from bus 1 to bus 7, we see that 33.33 MW flow on the line between bus 3 and bus 5, implying a distribution factor of 1/3.

Under the DC-Load model assumption, the distribution factor is constant. Doubling the input and output would double the flow on each line.

Power Flow and Distribution Factors
(Bus 1 to Bus 7)

Line	Distribution Factor
1->2	1/2
1->3	1/2
2->4	1/6
2->6	1/3
3->4	1/6
3->5	1/3
4->5	1/6
4->6	1/6
5->7	1/2
6->7	1/2

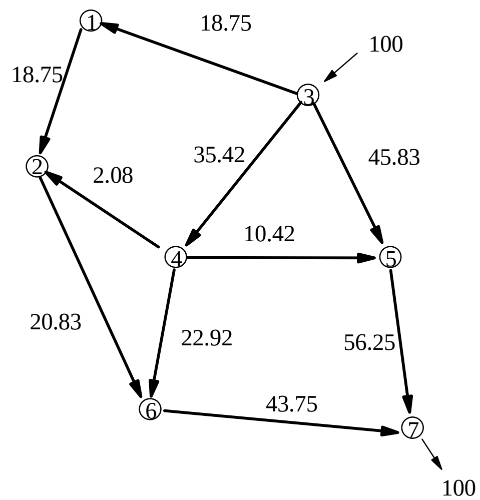


Similarly, the subsequent figure illustrates the same calculations for a transfer from bus 3 to bus 7. Now the flow on the line between bus 3 and bus 5 is 45.83, implying a distribution factor on this line of 11/24. Note also that the distribution factors on some lines are negative. For example, consider the line between bus 1 and bus 3. This illustrates that the transfer from bus 3 to bus 7 creates some counterflow relative to the transfer from bus 1 to bus 7.

Power Flow and Distribution Factors

(Bus 3 to Bus 7)

Line	Distribution Factor
1->2	3/16
1->3	- 3/16
2->4	- 1/48
2->6	5/24
3->4	17/48
3->5	11/24
4->5	5/48
4->6	11/48
5->7	9/16
6->7	7/16

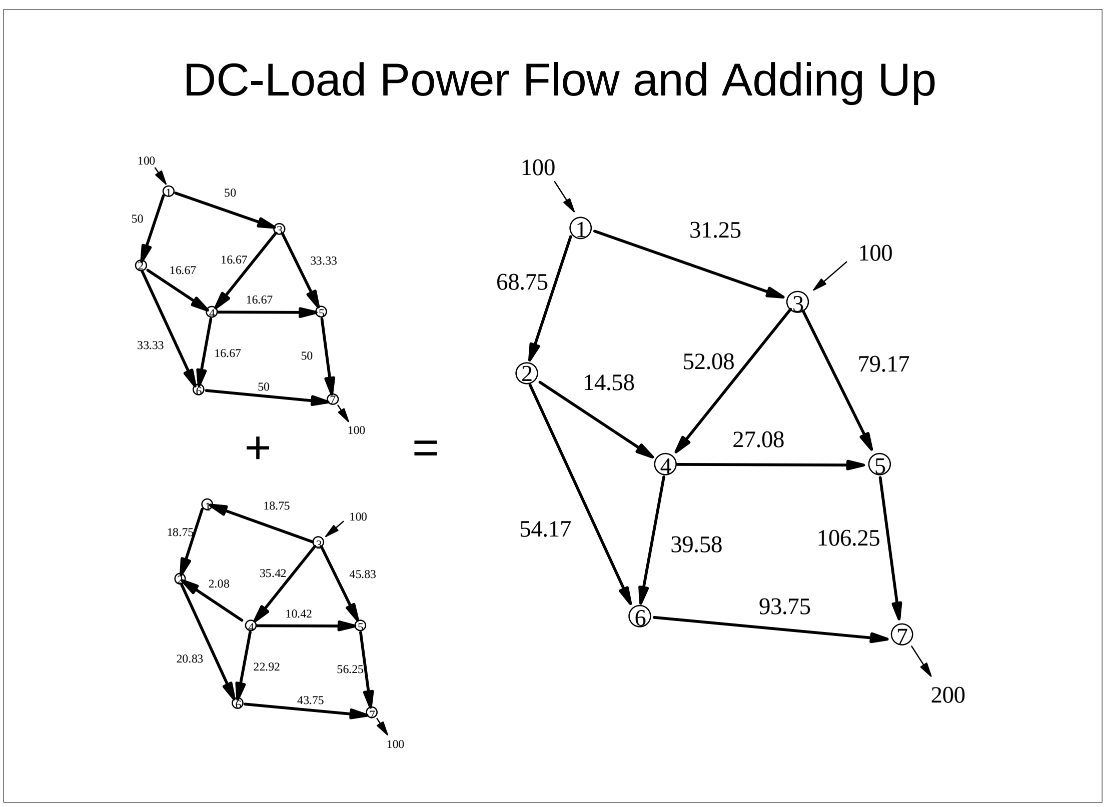


Similar calculations would produce the distribution factors from each bus to bus 7. Once the distribution factors are available for one arbitrary reference bus, the distribution factors between any pair of buses would be obtained by decomposing the transaction into two steps to and from the reference bus. Adding the system balance constraints and considering the sign convention of loads minus generation, we would obtain the matrix H as:[23]

[23] F. C. Schweppe, M. C. Caramanis, R. D. Tabors, and R.E. Bohn, Spot Pricing of Electricity, Kluwer Academic Publishers, Norwell, MA, 1988. For comparison, Scheweppe et al. use the opposite sign convention and would not include the last column and row, describing the result as the transfer admittance matrix, treating system balance and reference bus quantity separately. For our purposes, the present convention is more concise. With constraints on both directions of line flows, the transfer admittance matrix of distribution factors would be repeated with the opposite sign to produce total constraints equal to two times the number of lines plus one. The vector *b* includes the transmission limit for each line in each direction plus the value zero for the system balance constraint.

Bus	1	2	3	4	5	6	7
Line				***H***			
1->2	- 1/2	3/16	- 3/16	0	- 1/16	1/16	0
1->3	- 1/2	- 3/16	3/16	0	1/16	- 1/16	0
2->4	- 1/6	- 17/48	1/48	1/6	1/16	- 1/16	0
2->6	- 1/3	- 11/24	- 5/24	- 1/6	- 1/8	1/8	0
3->4	- 1/6	1/48	- 17/48	1/6	- 1/16	1/16	0
3->5	- 1/3	- 5/24	- 11/24	- 1/6	1/8	- 1/8	0
4->5	- 1/6	- 11/48	- 5/48	- 1/3	3/16	- 3/16	0
4->6	- 1/6	- 5/48	- 11/48	- 1/3	- 3/16	3/16	0
5->7	- 1/2	- 7/16	- 9/16	- 1/2	- 11/16	- 5/16	0
6->7	- 1/2	- 9/16	- 7/16	- 1/2	- 5/16	- 11/16	0
Balance	1	1	1	1	1	1	1

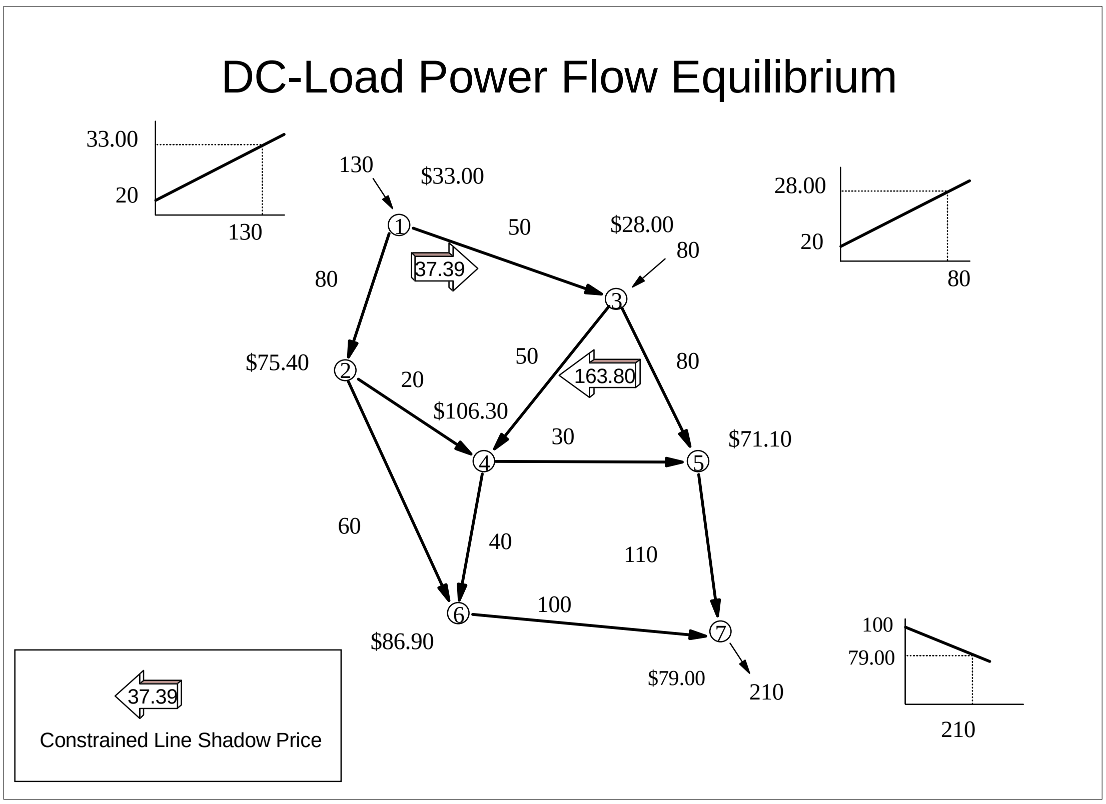
An important feature of the constant distribution factors in the DC-Load approximation is the "superposition" or adding-up of solutions. Hence, if we combined the power transfers from the first case from bus 1 with the second case from bus 3, we find that the resulting power flows on the lines are just the sums of the flows in the individual cases. As shown in the figure, the combined transfers produce a total of 31.25 MW moving on the line between bus 1 and bus 3, equal to the initial 50 MW minus the counterflow of 18.75 MW.



This description of the network is simplified, but it illustrates the important effects of loop flow. Inputs and outputs at any of the buses can affect the flow on every line, and there is no simple way to describe the path of the power flow in the network. Nonetheless, the market model yields market equilibrium with prices equal to marginal opportunity costs. Within this framework, the associated equilibrium prices in (3) would become:

$$p = H^t \mu. \tag{8}$$

To illustrate, consider the figure that takes the same seven bus network with the addition of bids for generation and load at buses 1, 3 and 7, respectively. Furthermore, there are constraints on the lines and, in the event, two of the constraints are binding. The resulting economic dispatch or market equilibrium is as shown in the figure. The equilibrium solution calls for injections of 130 MW at bus 1 and 80 MW at bus 3. The load of 210 MW is all at bus 7.



The shadow prices for the binding constraints are \$37.39 for the line between bus 1 and bus 3, and \$163.80 for the line between bus 3 and bus 4. Hence, the marginal value of increasing the capacity on the line between bus 3 and bus 4 is \$163.80.

The prices at every location can be calculated directly from the distribution factors and these shadow prices. For example, the price at bus 1 is the price at the reference bus (\$79.00) less the shadow prices times the respective distribution factors between bus 1 and bus 7. Hence, \$33.00=\$79.00 - \$37.39*1/2 - \$163.80*1/6. Likewise, for bus 3, \$28.00=\$79.00 + \$37.39*3/16 - \$163.80*17/48.

There are two ways two interpret this solution. In the LMP-FTR framework, the coordinated spot market run by the system operator would include bilateral schedules and the associated adjustment bids at bus 1, bus 3 and bus 7. The system operator would solve for the economic dispatch and the corresponding locational prices. Bilateral transfers in the system would be charged at the difference in locational prices. Hence, a schedule between bus 3 and bus 7 would face a congestion charge of \$51.00=\$79.00 - \$28.00. An FTR between bus 1 and bus 5 would receive a payment of \$38.10=\$71.10 - \$33.00. And so on.

The FGR interpretation would focus on the constrained lines, which would be defined as flowgates. The capacity of the flowgates would be defined and auctioned in a market, with trading in a secondary market. For example, the line between bus 3 and bus 4 would be defined as a flowgate and the capacity limit of 50 MW would be sold in advance, say to 50 participants with 1 MW each. These holders of rights on this flowgate could keep them or sell them to others in a secondary market.

Anytime market participants arranged a transaction between two locations, the participants would use the distribution factor matrix to determine how much of the transaction would flow over the respective flowgates. The participants would then purchase the appropriate number of flowgate rights. Hence, a 1 MW transaction from bus 1 to bus 7 would require 1/2 of a flowgate right on the line between bus 1 and bus 3 plus 1/6 of a flowgate right on the line between bus 3 and bus 4. Each transaction between a pair of locations would apply the relevant distribution factors to describe the actual flow over the flowgate.

Note that the transaction between bus 3 and bus 7 appears slightly different. The transaction requires 17/48 of an FGR on the line between bus 3 and bus 4. However, the transaction also provides counterflow on the line between bus 1 and bus 3. Hence it requires 3/16 of an FGR for the line between bus 3 and bus 1 and obtains a credit for 3/16 of an FGR for the line between bus 1 and bus 3. If the constraint is in the opposite direction of the flow, in effect the constraint price is negative and the transaction is required to pay under that FGR. This is essential to the proof of the efficiency of the flowgate trading rule.[24] In fact, this flowgate trading rule requires transactions to acquire rights and credits in both directions on every flowgate, and to pay or be paid according to the direction of the congestion. This feature will be relevant in the discussion below as to the interpretation of the flowgate rights as options or obligations.

With this flowgate definition and trading rule, ignoring transactions costs and assuming timely convergence, it can be shown that the equilibrium prices for the flowgate rights must be the same as the shadow prices in the optimal dispatch.[25] In other words, with the flowgate assumptions, the equilibrium prices for the FGRs are defined by the shadow

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[24] Hung-po Chao and Stephen Peck, "A Market Mechanism for Electric Power Transmission," Journal of Regulatory Economics, Vol. 10, No. 1, 1996, pp. 25-59. Hung-po Chao and Stephen Peck, "An Institutional design for an Electricity Contract Market with Central Dispatch," The Energy Journal, Vol. 18, No. 1, 1997, pp. 85-111.

[25] For further details, see Hung-po Chao and Stephen Peck, "A Market Mechanism for Electric Power Transmission," Journal of Regulatory Economics, Vol. 10, No. 1, 1996, pp. 25-59. For the equilibrium price definition, see also F. C. Schweppe, M. C. Caramanis, R. D. Tabors, and R.E. Bohn, Spot Pricing of Electricity, Kluwer Academic Publishers, Norwell, MA, 1988. pp. 161-162.

prices μ and these are related in turn to the locational prices at each bus according to the distribution factor matrix interactions. The value of a portfolio of flowgate rights that fully matched all the uses on the grid for a given point-to-point transaction would be equal to the value of an FTR between the same two locations. Hence, the payment under the flowgate rights for a transaction from bus 1 to bus 7 would be $46.00=$37.39*1/2 + $163.80*1/6, exactly compensating for the congestion cost differential between the two locations. The payment under the flowgate rights for the transaction between bus 3 and bus 7 would be $51.00= - $37.39*3/16 + $163.80*17/48. The FGR holder is paid $58.00=$163.80*17/48 for the value of its rights on the flowgate between bus 3 and bus 4, but must pay $7.00=$37.39*3/16 for the obligation under its counterflow from bus 3 to bus 1. Furthermore, the equilibrium price at bus 3 must be $28.00=$79.00 - $51.00.

The many schedulers would acquire the rights on the flowgates. Because the assumptions imply that distribution factors are constant, the individual schedules determine individual line flows that add up to the total line flows. Furthermore, because the line capacity is fixed, the capacity allocated either equals the total line flows or the price of the flowgate right reduces to zero. No one could get more capacity on a flowgate than the total capacity. In the illustration, the price of load at bus 7 is high and the prices of generation at bus 1 and bus 3 are low. Clearly generators would like to produce more and sell to load. However, they would have to purchase rights on the flowgates, which becomes the cost of transmission. Because flowgates are required in proportion to the constant distribution factors, the equilibrium price of point-to-point transmission is just the difference between the locational prices.

The contractual and scheduling rights conferred by the FGRs differ among the versions of specific flowgate proposals. In some proposals the rights might be required for any physical delivery of power through real time schedules. In other proposals, the FGRs would not be required for scheduling energy delivery but would provide a hedge against real time congestion. The details here are important, but they are still evolving in the proposals. For the moment, we highlight the conclusion that if the participants purchase flowgate rights according to these rules, the assumptions of the flowgate model imply the same market equilibrium as with the theory of the LMP/FTR framework.[26]

There are many claims for the benefits of the flowgate model, either on its own or in comparison with the LMP/FTR model defined above. To many it is a more intuitive way to describe the market. Reliance on decentralized trading of flowgates rather than coordinated trading of FTRs is a major motivation. Although the FTR formulation allows for some decentralized trading and reconfiguration of the individual rights, this decentralized trading would be limited to rearrangement of the parts without changing the aggregate pattern of inputs and outputs. To change the aggregate pattern of FTRs would require a coordinated auction. By contrast, if all the FGRs were made available in the market, changes in the aggregate pattern could be made without requiring central coordination. Supposedly this would produce large savings by avoiding the putative large costs of the system required to implement the LMP/FTR market.

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[26] The flowgate proposals that point to this conclusion typically cite the trading rule and analysis in Hung-po Chao and Stephen Peck, "A Market Mechanism for Electric Power Transmission," Journal of Regulatory Economics, Vol. 10, No. 1, 1996, pp. 25-59.

Other things being equal, enhanced opportunities and instruments for forward trading would be desirable, whether the forward trading is through decentralized transactions or through coordinated auctions. However, other things are not always equal, and the tradeoffs reduce to an empirical evaluation of costs and benefits. The importance of this difference in design is largely an empirical question. Most of the other claims of the benefits of the flowgate approach follow from predictions about the empirical outcome. For example, much relies on a conjecture that trading will be limited to a few flowgates. This would make it easier to assemble a portfolio of required FGRs. Furthermore, the claim is that reduction of all transmission transactions to a few flowgate rights would improve liquidity in the short-term trading market for transmission rights.

A main theme in the arguments for FGRs is that they are inherently options, with bounded down-side risk from price reversals as compared to FTRs, which are described as inherently obligations with significant down-side risk. However, as mentioned above, the FTRs could be defined as options, at some cost of increased complexity as compared to FTR obligations. And the interpretation of FGRs as options is a little more complicated than it appears on the surface. The flowgate model faces a similar set of problems when it must take account of the effect of counterflow. In particular, the point-to-point schedules that create counterflow must be treated as obligations if the implicit impact of counterflow is to be recognized by the flowgate model, as we will discuss further below.

However, under the flowgate assumptions and trading rule, there is no debate that the two approaches lead to the same equilibrium. Even more important, under the flowgate assumptions there need be no serious debate about the proper market design. Assuming that we could treat the FGRs as financial hedges at the equilibrium constraint prices, the simple answer would be "do both." The system operator could offer both types of rights and the market participants could acquire either or both. The simplifying assumptions are powerful, and with them much could be done.

The debate is about the flowgate assumptions.

FLOWGATE WRONGS

There are many variants of such link-based transmission rights that one can imagine, and the industry has been struggling with these ideas for years. Substantial questions arise in deciding on the details for the rules of implementation. Most important is the question of just how the system operator would perform certain functions or what would happen when something went wrong. Larry Ruff has described a number of these issues and pointed to critical concerns with the flowgate model.[27] As described by Ruff, these concerns arise even within a context where many of the assumptions of the flowgate approach might be accepted on their face. The present analysis complements the Ruff comments by examining the plausibility of the critical assumptions in light of other examples and some empirical evidence.

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[27] Larry E. Ruff, "Flow-Based Transmission Rights and Congestion Management: A Comment," San Francisco, CA, July 22, 2000.

Here the flowgate proposal follows the outline above. Some argue that the electric system is more complicated and there are simply too many lines and possible constraints to manage in a decentralized environment. The flowgate proponents argue that it is not necessary to consider all the lines and all the possible constraints. Rather they propose to consider only a few critical constraints, the commercially significant flowgates, and focus decentralized trading on these. The assertion is that the commercially significant transmission congestion can be represented by a system with:

- Few flowgates or constraints.
- Known and fixed capacity limits at the flowgates.
- Known and fixed power transfer distribution factors that decompose a transaction into the flows over the flowgates.

Under these simplifying assumptions, the decentralized model might work in practice. The RTO and its system operator would identify the flowgates. The capacity rights would be allocated or auctioned somehow to the market participants. Similarly, the RTO would publish the PTDF tables that would allow individual market participants to compute the effect of their transactions on the flowgates. The participants would then purchase the corresponding flowgate capacity rights in the market. This trading of capacity rights would take place in decentralized forward markets. Transactions that had assembled all the capacity rights needed would then be scheduled without further congestion charges. Real-time operations would be handled somehow, typically not specified fully as part of the flowgate model.

There is some experience with this flowgate model. However, the experience is limited and what experience we do have is not good. In particular, these simplifying assumptions and the corresponding flowgate model for decentralized congestion management were applied as part of the NERC Pilot Project for Market Redispatch in 1999, to create a decentralized alternative to administrative TLR curtailments. In the end, and despite the substantial turmoil created by the TLR system, the result was that apparently there were *no* successful applications of any decentralized trades under this approach.[28] By contrast and at the same time, the centralized coordinated market in PJM under the LMP/FTR model regularly provided successful market alternatives to administrative TLR curtailments. Perhaps the flowgate problems will be ironed out as the NERC experiment continues,[29] but the experience reinforces the need to look more closely at the flowgate model.

Despite the appeal of a move away from the contract path model and closer to the actual underlying reality of the transmission network, these generic methods built on flowgate rights must confront the problems inherent in the simplifications. Are there only a few flowgates? Are the capacity limits known and fixed in advance? Are the PTDF impacts known and fixed in advance of real-time? And so on. Those who hesitate in

[28] Congestion Management Working Group of the NERC Market Interface Committee, "Final Report on the NERC Market Redispatch Pilot," November 29, 1999, filed with FERC on December 1, 1999.

[29] NERC, "Market Redispatch Pilot Project Summer 2000 Procedure," March 31, 2000.

accepting the flowgate model as a method for organizing the use of the transmission system would answer in the negative for some or all of these questions.

Many Constraints

There are many potential constraints, so it would be necessary to obtain capacity rights on many flowgates. The number of rights that would have to be acquired in a complete version of a flowgate model generally would not be determined simply by the amount of power that flows in the actual dispatch. Under current practice, the system operators typically adhere to "(n-1) contingency" constraints on power flows through the grid. This requires that the allowed power loads at every location in the transmission system be such that in the event one of a series of possible contingencies occurs, the instantaneous redistribution of the power flows that would result would meet minimum standards for thermal limits on lines and would avoid voltage collapse throughout the system. We can think of the terminology as coming from the notion that one of the "n" lines in the system may drop out of service, and the system must still work with the (n-1) lines remaining. The actual contingencies monitored can be more diverse, but this interpretation conveys the basic idea of an (n-1) contingency-constrained power flow.

Hence, a single line may have a normal limit of 100 MW and an emergency limit of 115 MW.[30] The actual flow on the line at a particular moment might be only 90 MW, and the corresponding dispatch might appear to be unconstrained. However, this dispatch may actually be constrained because of the need to protect against a contingency. For example, the binding contingency might be the loss of some other line. In the event of the contingency, the flows for the current pattern of generation and load would redistribute instantly to cause 115 MW to flow on the line in question, hitting the emergency limit. No more power could be dispatched than for the 90 MW flow without potentially violating this emergency limit. The net loads that produced the 90 MW flow, therefore, would be constrained by the dispatch rules in anticipation of the contingency. It would be the contingency constraint and not the 90 MW flow that would set the limit. The corresponding prices would reflect these contingency constraints.[31]

Depending on conditions, any one of many possible contingencies could determine the current limits on the transmission system. During any given hour, therefore, the actual flow may be, and often is, limited by the impacts that would occur in the event that the contingency came to pass. Hence, the contingencies don't just limit the system when they occur; they are anticipated and can limit the system all the time. In other words, analysis of the power flows during contingencies is not just an exception to the rule; it is the rule. The binding constraints on transmission generally are on the level of flows or voltage in post-contingency conditions, and flows in the actual dispatch are limited to ensure that the system could sustain a contingency.

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[30] Expressing the limits in terms of MW and real power is shorthand for ease of explanation. Thermal limits are actually in terms of MVA for real and reactive power.

[31] Jacqueline Boucher, Benoit Ghilain, and Yves Smeers, "Security-Constrained Dispatch Gives Financially and Economically Significant Nodal Prices," Electricity Journal, November 1998, pp. 53-59.

By itself, this contingency-based analysis does not move outside the formal description of the flowgate model. But it does mean that the constraint matrix in *H* must be obtained for each contingency, simply because different contingencies would produce different distribution factors. Operation of a complete flowgate model, therefore, would require a trader to acquire the rights on each link sufficient to cover its flows on that line in each post-contingency situation.

A sometime argument is that this problem is not serious because the actual dispatch will have only a few of the potential constraints actually binding. Typically this is true, but it does not avoid the difficulty for the simple reason that we don't know in advance which constraints will be binding. Were it otherwise the system operator would not have to monitor all the constraints that are typically considered. In fact, the large list of potential constraints monitored by the system operator is already a select group identified as the important subset from the thousands or millions of possible constraints that could be defined given the large number of lines and the large number of contingencies. The mere fact that the system operator has identified the constraints would arguably be enough to require an associated flowgate capacity right in order to ensure that the resulting transaction would be feasible.

The accumulating experience in PJM is well documented and amply illustrates the point. In one outside study intended to support the development of zonal pricing and decentralized congestion management through something like a flowgate model, a set of 28 constraints were identified as important and analyzed for the variations in the equivalent of a PTDF table. While 28 may seem a large number and difficult to deal with in assembling the capacity rights to use the transmission system, it turned out not to be large enough. In the event, the first six months of operation of locational pricing in PJM found 43 constraints actually binding. Most importantly, *none* of these actual constraints were in the list of 28 supposedly easy-to-identify flowgates.[32] This suggests the magnitude of the difficulties faced when predicting which constraints will be binding. And the list of real constraints continues to grow. Over the period January 1998 to April 2000, there were 161 unique constraints that produced congestion and different locational prices in PJM.[33] Apparently a complete flowgate model would require purchase of at least 161 capacity rights to secure a single point-to-point transaction. And the list is growing.

The response to this accumulating evidence has been that there are only a few commercially significant flowgates that would need to be included, few enough to allow for decentralized trading and assembly of portfolios without creating significant transaction costs. Hence, the claim is that "a given transaction will significantly impact only a few

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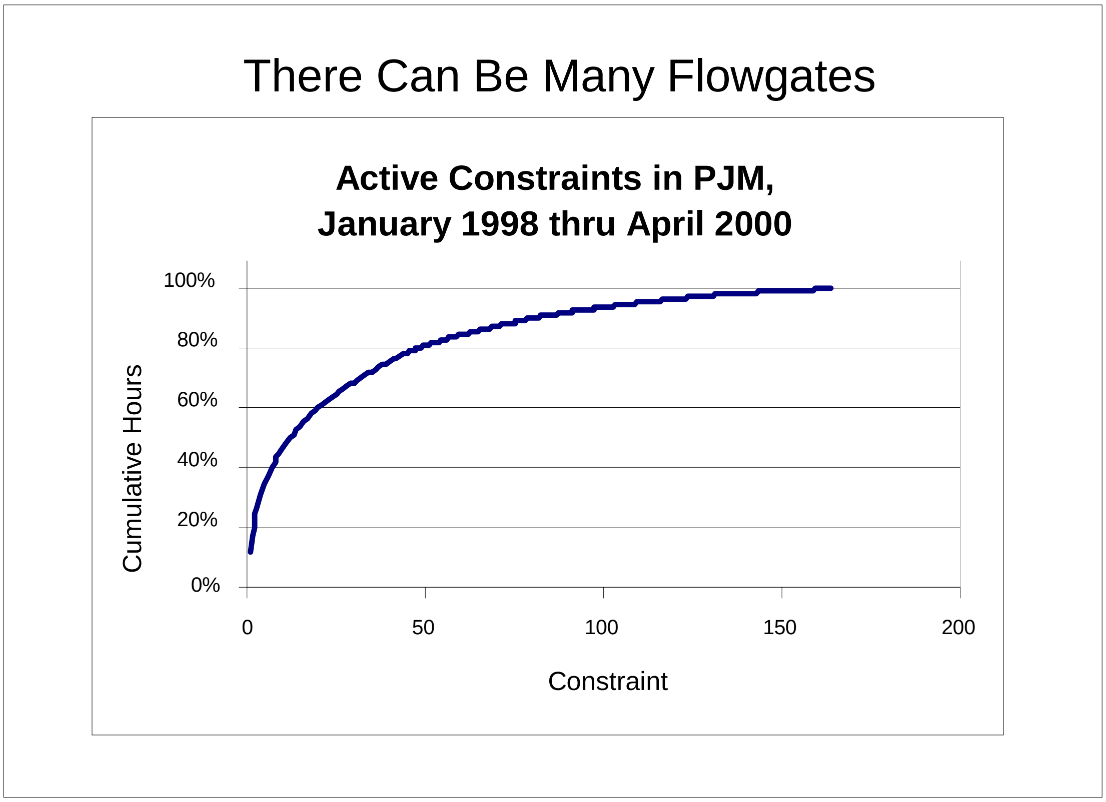
[32] Richard D. Tabors, "Transmission Pricing in PJM: Allowing the Economics of the Market to Work," Tabors Caramanis & Associates, February 24, 1999, p. 31. This is a careful study that is among the rare instances with easily available and documented assumptions. See the PJM web page for the record of actual constraints.

[33] See the PJM web page spreadsheet report on historical transmission limits, "Historical_TX_Constraints.xls." Over the period January 1998 to April 2000 there were 610 constraint-days recorded, with the same constraint appearing on more than one day. There were 4,313 constraint-hours. There was some smaller number of constrained hours, as many hours have multiple constraints. Based on the "Monitor" and "Contingency" names, corrected for typographical errors in the names, there were 161 unique constraints.

flowgates,"[34] or a " [t]he number of resulting [Commercially Significant Flowgates] CSFs is likely to be small."[35] More concretely "[a]lthough there is potentially a large number of flowgate rights, the system operation can be simplified further by using a fixed but small (say, up to 10) floating flowgate rights to set scheduling priority."[36] Here there is some evidence that is available and instructive. Although the flowgate right models have not been specific about how to define the constraints that are commercially significant, we do know something about our ability to predict which constraints will be limiting. As summarized above, the prediction record so far has been bad. When we look at the constraints that have been limiting, the number is quite a bit larger than predicted. Of course, not all constraints are equal, and some would be more important than others. How many would be enough, and how would we decide?



The figure shows the same data for the PJM case sorted to identify the cumulative number of constrained hours for each constraint.[37] It is true that there were many

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[34] Ed Cazalet and Ralph Samuelson, "The Power Market: E-Commerce for All Electricity Products," Public Utilites Fortnightly, February 1, 2000, p. 5.

[35] Tabors Caramanis & Associates, "Real Flow A Preliminary Proposal for a Flow-based Congestion Management System," Cambridge, MA, July 18, 2000, p. 9.

[36] Hung-po Chao, Stephen Peck, Shmuel Oren, and Robert Wilson, "Flow-based Transmission Rights and Congestion Management," August 18, 2000 (forthcoming Electricity Journal), p. 23.

[37] The data are not available for the measure of the value rather than just the duration of the

constraints that were binding for only a few hours. However, it is also true that in order to cover a large fraction of the hours it would be necessary to include many constraints as flowgates. An illustration in a TCA analysis suggests that 90% of the hours might be required,[38] which would mean close to 100 flowgates. Even 80% of the hours in this description of past PJM congestion would imply approximately 50 flowgates for this control area. There could be more in the future, and even more in trades among control areas.

Changing Capacity Limits

The obstacle of too many constraints to specify a complete flowgate model might be overcome if it were still possible to identify in advance how much capacity there is at each flowgate. This is an old problem with the uncomfortable reality that for many of the constraints it is not possible to specify the limiting value without also knowing the pattern of generations and loads and related transmission parameters.

This same set of difficulties troubles the LMP/FTR model, but only as a settlements matter. If the initial allocation of FTRs becomes infeasible due to changing transmission parameters, there might be a revenue adequacy problem. However, there would be no concern about achieving feasible dispatch at the efficient equilibrium. By definition, the LMP equilibrium would deal with the real constraint values and produce the corresponding locational prices. This would not be true for the pure flowgate model.

Many of the constraints in transmission systems are like the idealized thermal limits on lines envisioned in the DC-Load model, but not all. There are many other constraints that are more complicated and they arise from features other than just the real power flow that is the focus of the flowgate model.

Consider the case of reactive limits to avoid voltage collapse. The voltage level in the real electric system is closely connected with the availability of reactive power, which is significantly affected by both real and reactive power flows. It is not possible to analyze the reactive power and voltage impacts within the framework of the simplifying assumptions of the DC-Load model, which implicitly assumes that there is exactly the right amount of reactive power at every location. However, to simplify operational analysis and control, it is common to convert the constraints in the full system into effective limits on real power flow on lines or sets of lines defined as interfaces.

In essence, the procedure is to postulate a set of base case power flows and then step up the schedules in a prescribed pattern. For each schedule, the resulting analysis of the full alternating current (AC) load flow identifies the voltages at certain critical locations. The result of this series of simulations is an empirical relationship between voltage and flow on the interface, as illustrated in the figure from the VEM Study Procedures Manual.[39]

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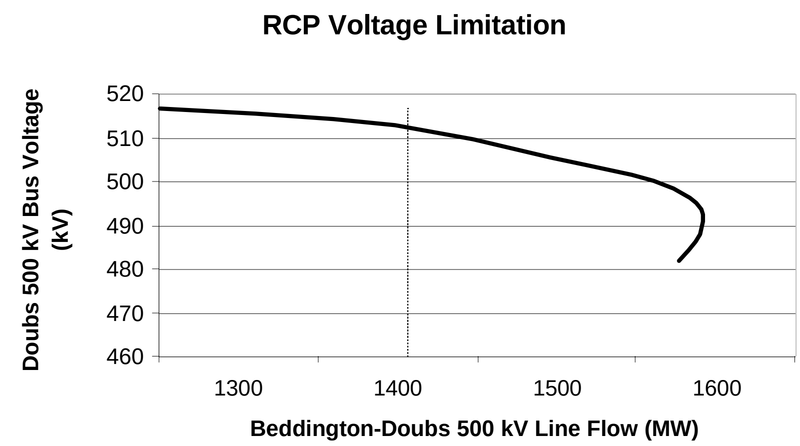
constraints.

[38] Tabors Caramanis & Associates, "Real Flow Model The Solution for Congestion Management," Cambridge, MA, Presentation for the Southwest Power Pool Congestion Management Subteam Meeting, July 31-August 1, 2000, p. 9.

[39] VEM Study Committee, "VACAR-ECAR-MAAC (VEM) Study Procedures Manual," May 3,



Source: VEM Study Procedure Manual, May 3, 1999

The typical voltage response curve displays the same shape, where the "knee" of the curve indicates imminent voltage collapse. Based on experience and judgment, the practice is to set a safe margin for the interface limit measured in the real power flow across the interface. Hence, in this case the limits might be set at 1400 MW across the Beddington-Doubs 500 kV line.

All this is acknowledged in the flowgate proposals to the effect that the limit on the flowgate would be 1400 MW, determined by the reactive constraint rather than the thermal limit on the line. Or the lesser of the two would set the flowgate capacity. Over a very short horizon this might be enough, but this argument runs against the notion that the decentralized trading is being handled in forward markets and the flowgates provide long-term transmission rights. The difficulty is that over any significant time frame, the magnitude of the reactive limit can change.

> "Consequently, some aspects of an operator's limit assessment are often necessarily subjective in nature, since a purely “textbook” or “automatic” assessment is often inadequate due to the practical nature of actual system operation and the uniqueness of real-time activities. … Briefly stated, the critical power flow assumptions include the following: bus loads are modeled as constant P and Q in both the pre- and post-contingency cases;

1999, pp. 38. (available at www.pjm.com) transformer taps that can regulate in the pre-contingency case are fixed in the contingency case; generators which regulate voltage at a remote bus in the pre-contingency case will be set to regulate their terminal bus at the pre-contingency voltage level in the contingency case; and phase angle regulators (PARs) will be set at a fixed angle in the contingency case (i.e., the PAR is allowed to act as a normal transmission line). PJM generator contingencies are modeled in the following manner: the generation amount out-aged is “picked-up” 85% at the swing bus (located on the western ECAR) and 15% at a bus in the New York Power Pool (NYPP) (located electrically “close” to the Gilboa bus). The modeling is used by the PJM Operations Planning group in their daily system."[40]

In particular, note that the assumptions used to set the reactive limit depend upon the pattern of use assumed in the base case and the pattern for incrementing the interface flows. This contradicts the assertion of the flowgate proposals that "[i]n contrast, the capacity of each link or flowgate is determined by physical factors associated with the link (e.g. thermal limit, voltage stability, and dynamic stability) and is generally insensitive to the power flow pattern."[41]

Furthermore, note that the description of the procedure refers to the daily system studies where these off-line calculations are adjusted to deal with the changing patterns of loads. Rather than being set once for an extended period of time, the limits are being revised regularly to deal with the changing patterns of use of the system. The interface constraints for voltage protection are routinely described as a range of maximum values on real power flows, with the actual value being set and changed regularly during real time operations. For example, the PJM Eastern Reactive Transfer Limit is reset at least every 15 minutes and can vary over a range of 4000 MW to 7000 MW, depending on system conditions.[42]

This is essentially the same problem as defining the available transmission capacity. As the New York Power Pool (NYPP) observed in a typical comment heard from system operators during the initial discussions on the design of transmission access rules:

> "The primary responsibility of the NYPP system operator is and must be to maintain the reliability of the bulk power system. The operator must have the flexibility to decide, for example, what level of transmission reserve capacity should be retained under various conditions and facilities' loadings to meet contingencies as they may arise. Thus, actual transmission availability, or, more correctly, available transmission transfer capability, may be less than the thermal limits of the facilities, and the difference may change as conditions

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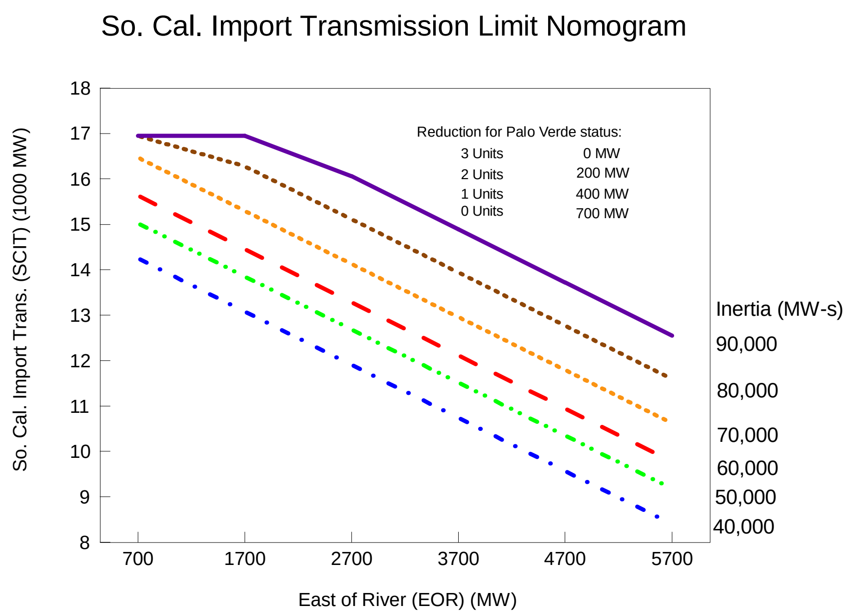
[40] VEM Study Committee, "VACAR-ECAR-MAAC (VEM) Study Procedures Manual," May 3, 1999, pp. 41-42. (available at www.pjm.com). Here P and Q refer to real and reactive power loads, respectively.

[41] Hung-po Chao, Stephen Peck, Shmuel Oren, and Robert Wilson, " Flow-based Transmission Rights and Congestion Management," August 18, 2000 (forthcoming Electricity Journal), p. 5.

[42] Andy Ott, PJM, personal communication.

change. The Commission should make certain that all participants understand and accept these factors."[43]

The same argument applies to stability studies, which again are outside the formal realm of the DC-Load model. Stability studies are conducted off-line to determine the transient interactions between power flows, frequency and voltages. Again a large dose of judgment is applied to isolate a safe region for real power flows in order to limit the actual dispatch. Typically, the limitations apply across more than one interface to represent interactions among the various power flows and the other system conditions.



Source: SDG&E. Inertia for Southern California on-line plants in MW-seconds.

The result is typically represented as a nomogram as illustrated in the figure for Southern California.[44] Again the interaction of the lines might be accommodated in the flowgate models by defining each segment of the piecewise linear nomogram limits as an

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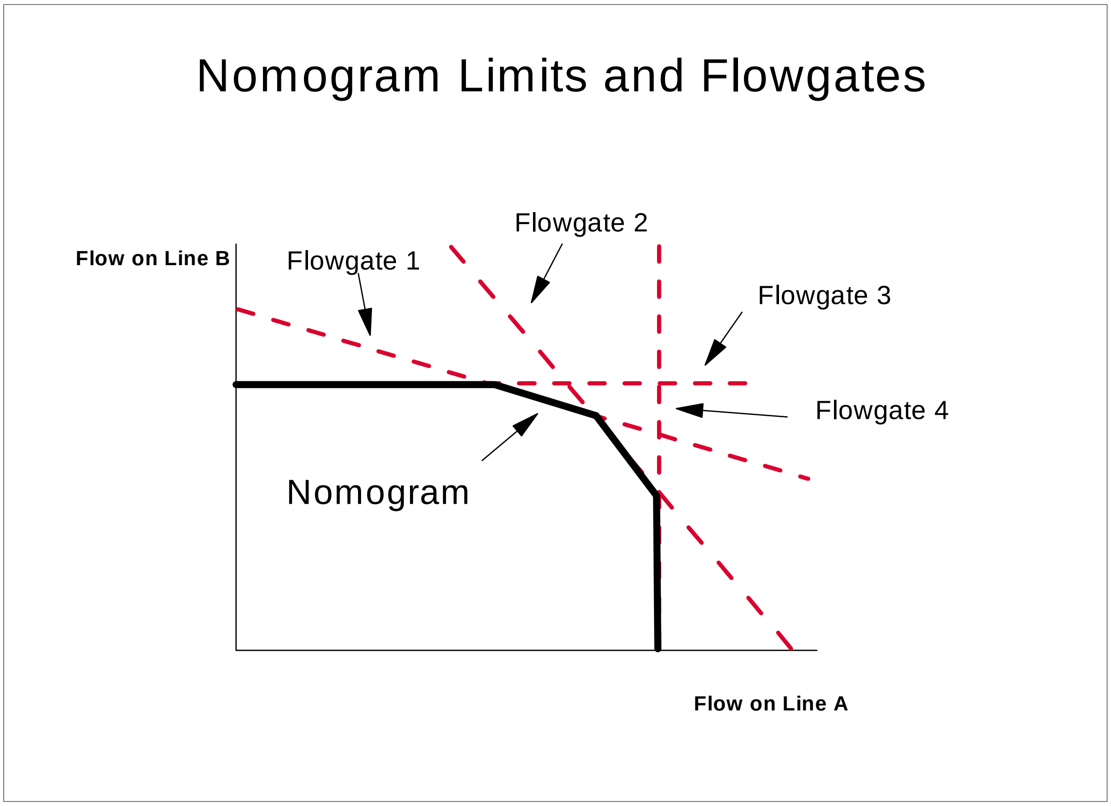
[43] Comments of Member Systems of the New York Power Pool, "Request for Comments Regarding Real-Time Docket Information Networks," No. RM95-9-000, Federal Energy Regulatory Commission, July 5, 1995, p. 9-10.

[44] Taken from Scott M. Harvey, William W. Hogan, and Susan L. Pope, "Transmission Capacity Reservations and Transmission Congestion Contracts," Center for Business and Government, Harvard University, June 6, 1996, (Revised March 8, 1997). This nomogram is from circa 1996 as provide by San Diego Gas & Electric. The current SCIT nomogram is referenced by the CAISO web page but listed as not published for security reasons. The current numbers are probably different, but the older version suffices to illustrate the point here.

additional flowgate. For example, as shown for the stylized flowgate in the following figure, the single nomogram would include four flowgates.



The reason that a nomogram is not just one flowgate is that the flowgate model defines the constraints and distribution factors in terms of the net loads in *y*. However, the typical nomogram is defined in terms of piecewise linear limits on the flows on the lines or interfaces. To translate the nomogram on the lines to linear constraints on the net loads, we would need to break the nomogram into its individual pieces. It is not enough, therefore, to say that a nomogram can be included as another constraint or flowgate. Under the linearity assumptions central to the definition of flowgate rights, the superposition of individual transactions to produce the total use of the flowgate limit requires linearity, not just piecewise linearity. A single nomogram implies many flowgates.

Assuming there were not too many pieces, this would unpack a nomogram into many linear constraints in the form required for the flowgate model. But note also that the limit on SCIT flowgate is a function of a number of variables that depend on current operation of the system, such as the inertia of the spinning shafts of generators in Southern California or the availability of Palo Verde units. Hence, the limits on the individual piece would change with system conditions.

The determination of whether stability or voltage limits will dominate is not obvious and depends on system conditions. Consider the following table describing a nomogram limit in the New York Power Pool. There are three different variables that depend on the system use and that determine the limit of the flow on the flowgate.

Exhibit B[45]
NYPP CENTRAL EAST: ESTIMATED PRE-CONTINGENCY FLOW LIMITS BASED ON VOLTAGE COLLAPSE V. STABILITY LIMITS

Oswego Complex Utility Units in Service	Number of Sithe Units in Service	SVC Status					
		2 SVC I/S		1 SVC I/S		0 SVC I/S	
		Volt	Stab	Volt	Stab	Volt	Stab
4/5 Oswego Units	6	**2890**	3100	**2860**	3000	2840	**2450**
	3	2830	**2800**	2810	**2700**	2780	**2450**
	0	**2780**	2800	2750	**2700**	2730	**2450**
3/5 Oswego Units	6	**2840**	3100	**2810**	2950	**2790**	2800
	3	**2740**	3100	**2720**	2950	**2690**	2800
	0	**2650**	2800	**2630**	2800	**2600**	2650
2/5 Oswego Units	6	**2760**	3100	**2740**	2950	**2710**	2800
	3	**2630**	3100	**2610**	2950	**2570**	2800
	0	**2500**	2800	**2480**	2800	**2440**	2650
1/5 Oswego Units	6	**2640**	2800	**2610**	2800	**2580**	2800
	3	**2440**	2800	**2410**	2800	**2380**	2800
	0	**2200**	2500	**2170**	2500	**2130**	2500
0/5 Oswego Units	6	**2180**	2500	2150	**1900**	2100	**1550**
	3	**1940**	1900	1910	**1900**	1870	**1550**
	0	**1700**	1900	**1670**	1900	1630	**1550**

Current nomograms exhibit even more complex interdependence than shown here. In the Western system the SPPCo export and import limit nomograms appear to have at least four dimensions of interaction among Utah flow, interchange flow, PGE and the Alturas interface.[46] More troubling yet, the two-dimensional projections of the nomograms (each with its own web address) indicate that an SPPCo nomogram is not always convex or

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[45] R. Gonzales, A. Hargrave, G. Campoli, D. Tran, "NYPP Central East Voltage Analysis," NYPP Internal Report, August 1995.

[46] www.sierrapacific.com.

as well behaved as the SCIT nomogram above.

Apparently there are many constraints that have capacities that are quite dependent on the pattern of power flows and system use. For these constraints, it is not possible to define in advance the available capacity if we want to provide long-term rights for the full capacity in the forward markets. The response in the flowgate proposals suggest some more limited allocation of flowgate rights, but then this calls into question the original argument about the efficiency of the resulting solution and the ability of the market participants to really ignore the constraints not included in the flowgates.

Changing Distribution Factors

In addition to recognizing that the capacity limits are not always known in advance, another reality is the changing value of the PTDF tables. In the true AC electricity system, the flows over the lines and voltages at the buses will depend on all the other receipts and deliveries on the grid. Thus, the flow over a particular flowgate that can be attributed to a particular transaction could be different than anticipated at the time of the allocation of the flowgate rights.

There are many causes of this ex ante ambiguity in the distribution factors. First, the PTDFs are a function of the entire configuration of the grid. With any line out of service, there are different PTDFs, and the configuration of the grid is changing all the time. This change in the topology of the grid would not matter in the bid-based economic dispatch that produces the locational prices. By definition, the LMP model takes the current grid configuration into account and the LMP prices capture the real interactions in the system. However, this change in the topology of the grid would affect application of both the point-to-point FTRs and the flowgate FGRs. In the case of the FTRs, changes in the topology of the grid may leave the FTRs as no longer simultaneously feasible. This is a necessary but not a sufficient condition for the expected compensation under the FTRs to exceed the collection of congestion rents. Hence, the actual dispatch would still be an equilibrium solution, but changes in the topology of the network may lead to a revenue deficit for the FTRs.

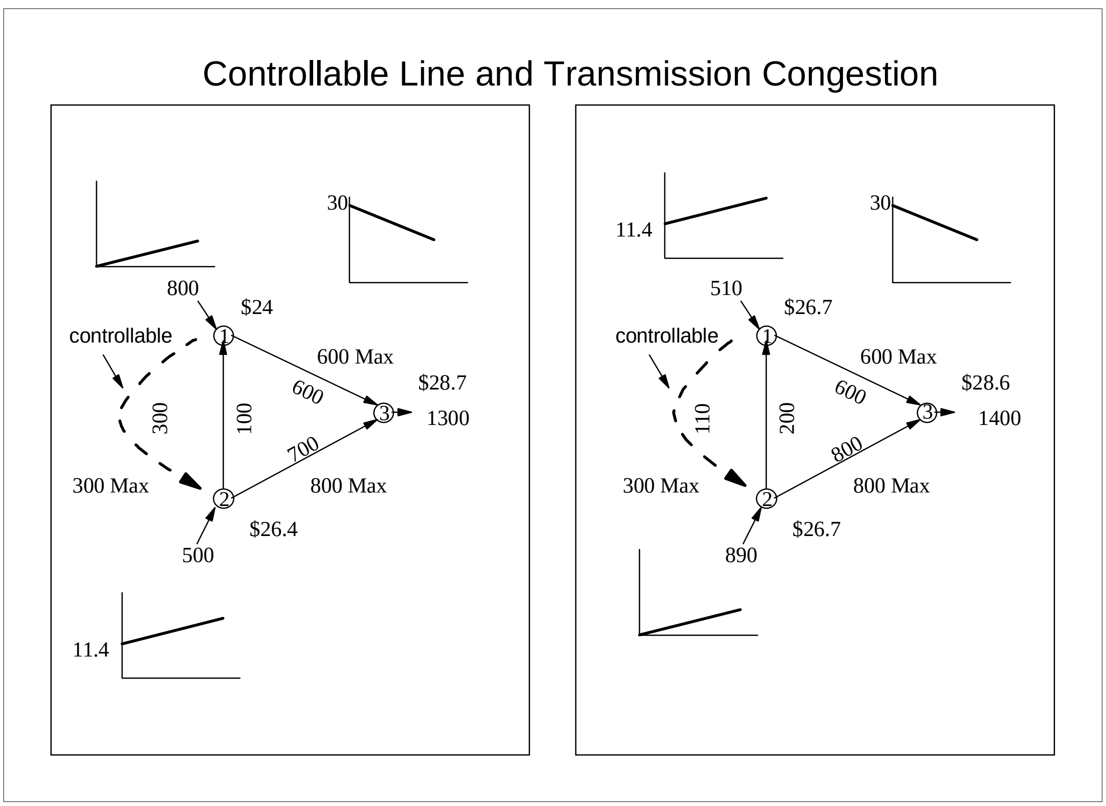
In the case of the flowgate rights, changes in the topology of the network would change the distribution factors. Hence, the actual use of the system would not conform to the flowgate assumptions. Schedules that would be feasible and produce the equilibrium solution under the flowgate model would no longer match the actual constraints on the system. The resulting schedules might be over or under the flowgate capacities. The equivalence between the equilibrium of the LMP model and the equilibrium of the flowgate model, as outlined above, would no longer apply. Hence, even with schedules that matched the flowgate rights at the assumed distribution factors, there could be a need to redispatch with resulting congestion costs for the flowgates.

Even without changes in the topology of the network, there are many electrical devices, such as phase angle regulators or direct current lines, whose very purpose is to change the apparent impedance of lines as a function of changing loads and, therefore, to change the PTDFs throughout the system. For example, if PARs did not significantly affect the distribution factors there would be no reason to incur the cost of installing the devices.

These controllable lines violate the assumptions of the free flowing network that is at the root of the constant distribution factors of the flowgate model. In reality, controllable lines are intended to add to the capability and flexibility of the grid, and a fully controllable network would eliminate many of the complications in creating and guaranteeing transmission rights. But in a network that has a mix of controllable and free flowing lines, the mixture complicates the assumptions of the flowgate model.

To illustrate the effect of controllable lines, consider the hypothetical network in the two panels of the accompanying figure. Here the network consists of three lines and three buses that follow the assumptions of the DC Load model. The lines are identical except for different flowgate limits as shown in the figure. Hence the distribution factors for this part of the network must be 1/3 and 2/3. For the three line network, 2/3 of the power moving from bus 1 to bus 3 would flow over the line between them, and 1/3 would flow over the other path through bus 2. Symmetrically, 2/3 of the power moving from bus 2 to bus 3 would flow over the line between them, and the remaining 1/3 would flow over the other path through bus 1.

In addition, there is a controllable line between bus 1 and bus 2, as indicated by the dashed line in the two panels.



For purposes of this example, we assume that the controllable line is able to move up to 300 MW in either direction. The two panels show two different sets of supply curves and the corresponding optimal solutions that each yield a market equilibrium with the corresponding locational prices.

Here we treat the controllable line as part of the economic dispatch optimization problem or market equilibrium. This produces locational prices in the natural way with the marginal distribution factors. We would obtain the same prices if we set the impedance of the controllable line to produce the right flow and then calculated distribution factors for that impedance.

The flowgate model assumes that we can identify constant distribution factors, and that these distribution factors times the inputs will determine the flows over the constrained lines. This is the adding up property that is necessary for flowgate trading to reproduce the same market equilibrium that would be obtained from the LMP bid-based economic dispatch.

However, to see the impact of the controllable line on the implied distribution factors, consider the inputs going from bus 1 to bus 3. One logical definition of the distribution factors would be different for the left panel and the right panel.

Distribution Factors for Bus 1

	Left	Right
Controllable	0.37	0.22
Flowgate Line 1->3	0.54	0.59
Flowgate Line 2->3	0.46	0.41

This treats all the flow on the controllable line as from bus 1, leaving the distribution factors for bus 2 the usual 1/3, 2/3 values for the three-bus example. Using these distribution factors will reproduce the flows. Hence, for example, in the flowgate model we would have available 600 MW of capacity on line 1->3 and the participants would purchase these rights in the market. However, they would have to use the distribution factors for the relevant solution. For example, in the right panel the total requirement for line 1->3 would be 0.59*510 + 0.33*890=600.

However, if we applied the distribution factors of the left panel to these same inputs, the apparent requirements for the line 1->3 would be 0.54*510 + 0.33*890=573, and the market price that would be obtained for these rights would presumably drop to zero. Similar calculations would find the rights to line 2->3 oversubscribed. Unlike the flowgate assumption, the real marginal and average distribution factors are not the same. But the efficiency proof for decentralized trading in the flowgate model requires that the average and marginal distribution factors be the same so that the individual uses of the flowgate add up to the correct total use. Apparently the flowgate model and its trading rule with constant distribution factors cannot reproduce the efficient market equilibrium.

By contrast, this description of the impact of controllable lines would not affect the viability of the LMP/FTR approach. For example, suppose that the inputs and outputs of the left panel were to define the set of simultaneously feasible FTRs. Then at the prices in the right panel, the congestion rents collected from the actual congestion would be larger than the payments under the FTRs. Or we could reverse the assignment and take the pattern of inputs and outputs in the right panel as defining the set of simultaneously feasible FTRs. Then at the prices in the left panel the congestion rents collected would exceed the payments under the FTRs. The FTRs would require total payments no greater than the total congestion rents (revenue adequacy). In this case, the changing distribution factors do not affect the revenue adequacy of the LMP/FTR model.[47]

One flowgate analysis describes the feature of the FTR point-to-point rights in accommodating changes in distribution factors as "PTDF insurance." There is an assertion that "…the cost to other market participants or to the ISO of fulfilling the obligations inherent in this insurance could be very large, and might have a substantial impact on the ISO's uplift charge in later years."[48] This conjecture may flow from an assumption that changes in distribution factors would necessarily make the FTRs infeasible, thereby exposing the system operator to some inappropriate financial risk. And investment in the grid as well as changed operating conditions could have a significant effect on distribution factors. As for investment to change the topology of the grid, the LMP/FTR model includes a feasibility rule that would preserve the existing FTRs or repurchases them to sell something that has a higher value.[49] Hence for the deliberate reconfiguration of the capacity of the grid, there is no exposure under the LMP/FTR model.

As for operations with any given topology of the grid, the example with the controllable line indicates that there is not necessarily any financial exposure despite changing distribution factors. The explanation for operations with a given grid has two elements. First, for revenue adequacy under market equilibrium it is sufficient that the

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47 The congestion rents and FTR payments would include:

Controllable Line Example

Left Panel			Right Panel		
Spot Market Charges			Spot Market Charges		
Q (MW)	Price	Payment	Q (MW)	Price	Payment
800	24	-19,200	510	26.7	-13,617
500	26.4	-13,200	890	26.7	-23,763
-1300	28.7	37,310	-1400	28.6	40,040
	Total	4,910		Total	2,660
	FTR Payments			FTR Payments	
Q (MW)	Price	Payment	Q (MW)	Price	Payment
510	24	-12,240	800	26.7	-21,360
890	26.4	-23,496	500	26.7	-13,350
-1400	28.7	40,180	-1300	28.6	37,180
	Total	4,444		Total	2,470
	Net	466		Net	190

48 Hung-po Chao, Stephen Peck, Shmuel Oren, and Robert Wilson, " Flow-based Transmission Rights and Congestion Management," August 18, 2000 (forthcoming Electricity Journal), p. 10.

49 For a discussion of this rule, see James B. Bushnell and Steven E. Stoft, "Electric Grid Investment Under a Contract Network Regime," Journal of Regulatory Economics, Vol. 10, 1996, pp. 61-79.

FTRs be feasible for some value of the transmission parameters that are under the control of the system operator, x. It is not necessary that the FTRs would be feasible at the current optimal setting of the transmission parameters, x^*. Second, infeasibility of the FTRs is a necessary but not sufficient condition for violation of revenue adequacy. In other words, almost by definition, revenue inadequacy of the FTRs requires both that there is no available transmission parameter setting that would make the FTRs feasible and that the FTRs would provide a preferred schedule at the current prices.

Hence, changes in grid conditions that could lead to the revenue inadequacy of FTRs must be limited to those conditions that are outside the control of the system operator (such as lines falling down) which the system operator otherwise would reverse in order to accommodate the preferred FTR schedule. Such events do occur, but these do not describe all the conditions that result in changed distribution factors. The actual practice of who bears the risk in the case of revenue inadequacy is different in different implementations, and could be connected to the discussion of incentives for the transmission owner responsible for line maintenance.[50]

The average distribution factor definition for the case of controllable lines is not unique, but there is an internal consistency requirement. If we know the optimal set of constraint multipliers, and apply these prices to either set of distribution factors, we get the right congestion prices. However, the distribution factors times the inputs will not add up to the flows on the lines, as required for the flowgate model.

A more elaborate version of a decentralized market in the flowgate spirit but with controllable lines might be the following. The operator of the controllable line could sell flows on the controllable line. From the generation source to the entry of the controllable line there would be one set of distribution factors, and from the exit of the controllable line there would be another set of distribution factors to the ultimate load destination. Hence, everyone who purchased service on a controllable line would have two sets of distribution factors that would be applied for every flowgate of the free flowing system. Assuming linearity of everything else, if there were more than one controllable line the required number of sets of distribution factors should be the number of controllable lines plus one. However, this hardly seems like it would be making the transactions simpler.

These types of nonlinearities and changing distribution factors are known to system operators. However, the system operators still talk about distribution factors and regularly use something like the DC Load model in actual operations. There is no contradiction here if we recognize that the DC Load model is not the only approach to a reasonable linearization of the transmission constraints. There are inherent nonlinearities in the flows and constraints, especially the ubiquitous nomogram constraints that attempt to approximate even more complex interactions in the system. These nonlinearities are complicated and it is much easier to work with linear approximations. However, there is no requirement that the linearization be constructed relative to zero load and flow as is done in the DC Load model. Rather, it is just as possible to obtain a solved load flow for all the parameters and loads (x_0,y_0) for the full AC system and then build the linear approximation relative to this

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[50] William W. Hogan, "Market-Based Transmission Investments and Competitive Electricity Markets," Center for Business and Government, Harvard University, August 1999, pp. 24-25.

load flow. In the terminology of the description of the transmission market model above, this would amount to representing the constraints as:

$$K(x,y) \approx K(x_0,y_0) + \nabla K_y(x_0,y_0)(y-y_0) \leq 0. \tag{9}$$

This could be written in the DC Load model form as:

$$\nabla K_y(x_0,y_0)y \leq \nabla K_y(x_0,y_0)y_0 - K(x_0,y_0). \tag{10}$$

But this makes explicit the dependence of both the distribution factors in $\nabla K_y(x_0,y_0)$ and the constraints limits in $\nabla K_y(x_0,y_0)y_0-K(x_0,y_0)$ on the assumed load flow and transmission parameters. At any moment, this model would look like a DC Load flow model in its form and be solved accordingly. But changes in the load flow or other transmission parameters could affect both the distribution factors and the constraint limits. The solved load flow (x_0,y_0) might be obtained by actually solving an AC load flow model, as in planning studies, or through direct measurement coupled with state estimation. In real time, for example, we have available a continuous update on the solution of the AC network produced by the real network itself. It is for these reasons that PJM updates both the load flow estimate and calculation of its equivalent of distribution tables every five minutes.[51] In reality, the PTDFs needed for a complete flowgate model would be anything but known in advance.

Balancing Market Requirements

The growing recognition of the reality that there could be a large number of constraints, that capacities might not really be known in advance, and that distribution factors might not be fixed, has changed the emphasis of the pure flowgate proposals from one of exact equivalence to the LMP/FTR market to one of handling some transmission congestion constraints in the forward market but relying on a balancing market to deal with the transmission congestion that is not addressed by the explicit flowgates. Hence, the "RTO will run a single real-time balancing market within the hour once the forward markets have closed." [52] Or that "[u]nderlying these issues is the fundamental reality that with the present technology, electricity markets are inherently incomplete, and the real-time dispatch of generation and transmission resources is most effectively managed by a central system operator. This suggests the necessity of a hybrid market architecture with multiple settlements of a sequence of decentralized forward markets and a centralized spot or real-time market."[53]

This is important progress, but it raises a number of questions of its own. Presumably this necessary balancing market would be designed as suggested based on a "centralized spot or real-time market." But this sounds like LMP without the FTRs, and

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[51] Andy Ott, PJM, personal communication.

[52] Tabors Caramanis & Associates, "Real Flow A Preliminary Proposal for a Flow-based Congestion Management System," Cambridge, MA, July 18, 2000, p. 10.

[53] Hung-po Chao, Stephen Peck, Shmuel Oren, and Robert Wilson, " Flow-based Transmission Rights and Congestion Management," August 18, 2000 (forthcoming Electricity Journal), p. 2.

not much of a huge saving in the cost of structuring the market. Furthermore, as emphasized by Ruff, this integration of the flowgate rights and the balancing market is easier said than done. The proposal of Chao et al. explicitly calls for efficient pricing where congestion is charged for all constraints and compensation is paid for the flowgate rights at the efficient flowgate prices. [54] The full details have not been specified, such as how to treat changed distribution factors. However, the spirit is to pay or charge the actual shadow prices for the constraints. This is a good rule in terms of its incentives but it implies that the resulting portfolio of flowgates between two locations provides only a partial hedge compared to the corresponding FTR.

By contrast, the proposal in the TCA description of the so-called "REAL Flow" model is for the costs of congestion other than the designated flowgates to be socialized: "The RTO will alleviate any real-time constraints through redispatch and meet imbalances simultaneously across the RTO. Redispatch to alleviate any constraints on the system other than on CSFs will be added to the cost of operating the system." [55] Other proposals envision that either socialization of the costs or efficient pricing could be married to a flowgate model.

The problems here could be significant. Note that the proposals for socialization of congestion costs amount to accepting from the forward market a set of schedules that are feasible in the hypothetical flowgate model but known to be infeasible in the real system. We have experience with such a system, as this design is at the core of the California market model that distinguishes between inter-zonal congestion that is priced and intra-zonal congestion that is socialized. The experience has been that the difference between the two sets of schedules creates substantial gaming opportunities where the hypothetical schedules produced congestion that the scheduler would then be paid to relieve. The Federal Energy Regulatory Commission found this system "fundamentally flawed," and it is now the subject of substantial reform efforts. [56]

If marriage between the flowgate rights and the real time dispatch is required to support efficient markets, the details of this connection are critical. Since the real time balancing market defines what really happens in the end, everyone involved in forward trading would need to anticipate the impact of the rules. Different rules would create different incentives. The reality is that the rules for the balancing market dictate the incentives that will be pursued in the forward market, not the reverse.

See Ruff for a further discussion of the problems of pricing in the balancing market. Assuming there are reasonable answers to Ruff's questions about the further

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[54] Hung-po Chao, Stephen Peck, Shmuel Oren, and Robert Wilson, " Flow-based Transmission Rights and Congestion Management," August 18, 2000 (forthcoming Electricity Journal), p. 21.

[55] Tabors Caramanis & Associates, "Real Flow A Preliminary Proposal for a Flow-based Congestion Management System," Cambridge, MA, July 18, 2000, p. 10.

[56] Federal Energy Regulatory Commission, "Order Accepting for Filing in Part and Rejecting in Part Proposed Tariff Amendment and Directing Reevaluation of Approach to Addressing Intrazonal Congestion," Docket ER00-555-000, 90 FERC 61, 000, Washington DC, January 7, 2000, p. 9. See also Federal Energy Regulatory Commission, "Order Denying Requests for Clarifications and Rehearing," 91 FERC 61, 026, Docket ER00-555-001, Washington DC, April 12, 2000, p. 4.

details, suffice it to say here that the flowgate proposal of Chao et al. does not appear to suffer from the perverse effects that would be expected from any system designed to socialize transmission congestion costs.

Options and Obligations

The several proposals for flowgates emphasize that a principal motivation is to provide transmission rights that are one-sided options and not two-side obligations. The implication is that FGRs are inherently options and FTRs are inherently obligations. Hence, the putative advantage of the flowgate model is that it provides options and the point-to-point FTRs cannot.

> "Underwriting point-to-point rights that have negative value poses commercial complications, yet is essential for full utilization of the network capacity since the number of rights that can be issued between different pairs of nodes are interdependent. In other words the transfer capability between two points may be greatly diminished unless a point-to-point right with negative value is underwritten. On the other hand, the available number of flowgate rights on a link is determined only by the contingency-adjusted flow constraints on that link independently of the rest of the network."[57]

This analysis confuses an implementation choice with a design requirement. In principle it is possible to implement the LMP/FTR model with point-to-point options, obligations or both. The difficulty is that there are tradeoffs in the capacity that can be allocated and the technical complications of the feasibility studies. The choice in PJM and New York has been to use FTR obligations initially, reserving the opportunity to expand the model to include FTR options at a later date. The proposal for Ontario is to have FTR options. The recent FERC ruling for New England would require both FTR obligations and options.[58] Likewise, it is possible to implement the flowgate model with options, obligations or both.

When it moves further to specifying the details, any flowgate proposal will face similar tradeoffs as were observed in the development of LMP/FTR implementations. To see the tradeoffs it is helpful to keep in mind whether or not the context is establishing transmission rights to provide hedges for power deals that require transmission, versus providing transmission rights for speculative trading separate from power transactions. In the idealized hedging application, the transmission right is combined with a long-term power contract between two locations. In speculative trading, the transmission right is an economic instrument traded without immediate corresponding trades of any power contract. Both uses have their value, but the risks are different.

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[57] Hung-po Chao, Stephen Peck, Shmuel Oren, and Robert Wilson, " Flow-based Transmission Rights and Congestion Management," August 18, 2000 (forthcoming Electricity Journal), p. 7.

[58] Federal Energy Regulatory Commission, "Order Conditionally Accepting Congestion Management and Multi-Settlement Systems," Docket Nos. EL00-62-000 and ER00-2052-00, Washington, DC, June 28, 2000, p. 33.

For the hedging function, the FTR obligation between the two points provides an exact hedge for the transmission charges associated with a power transaction from the source to the destination. If the price difference between source and destination is positive, the transmission charge is exactly balanced by the payment under the FTR. If the price difference is negative, so is the transmission charge and there is no risk exposure merely from the change in prices. Hence, the downside risk for an FTR obligation applies only to a speculative holding not matched with a power transaction.

In the flowgate model, the rights are also directional. There are two possible interpretations of the character of the flowgate right as an option. One interpretation might be that the hedger purchases rights to match the directional flows that it induces but takes on no obligation for the implicit expansion of capacity in the counterflow direction. Hence, if the right is from bus 1 to 3, the hedger collects on the rights if there is congestion in the direction from bus 1 to bus 3 but does not pay if the congestion reverses. In this interpretation, the maximum quantity of rights available is the physical capacity of the flowgate. For the moment, call this the pure option interpretation of FGRs, which may be what is intended in some flowgate proposals. It also seems that this interpretation may be read into all the flowgate proposals even if it is not intended.

An alternative interpretation would be that the hedger obtains flowgate rights to match the directional flows that it induces but also is credited with flowgate rights for the counterflow that it creates. These counterflow rights would be obligations that would require a payment by the holder whenever the congestion was reversed on the particular flowgate. However, for the speculator who holds rights on lines not sold for a hedging transaction and not ultimately converted to schedules, there is no obligation or responsibility for counterflow payments. This is not the same as the pure option model. However, this alternative interpretation is consistent with what is described in the theory of Chao and Peck. Although this feature of their flowgate model theory is not emphasized in the examples, it is clear in the theory and made explicit in at least one illustration.[59] For the moment, call this the mixed option and obligation interpretation of FGRs, which may be what is intended in some flowgate proposals.

In order to provide an exact hedge for a power transaction in the flowgate market, it would be necessary to obtain flowgate rights on all the flowgates. However, in the case of counterflow on a particular line, the pure flowgate option model would not include credit for the counterflow impact. Hence, the pure option version of the flowgate model could not provide a complete hedge and could not support the equilibrium market solution.

To see this, consider again the seven bus example discussed earlier. The flows add up, but not the flowgate capacities of the pure option model. For example, suppose there were a constraint of 50 MW in either direction on the line between bus 1 and bus 3. The market equilibrium diagram (repeated below) shows the net flows for the combined inputs, and this set of flows would be feasible with respect to this constraint. However, under the pure option flowgate model market participants would not be able to acquire

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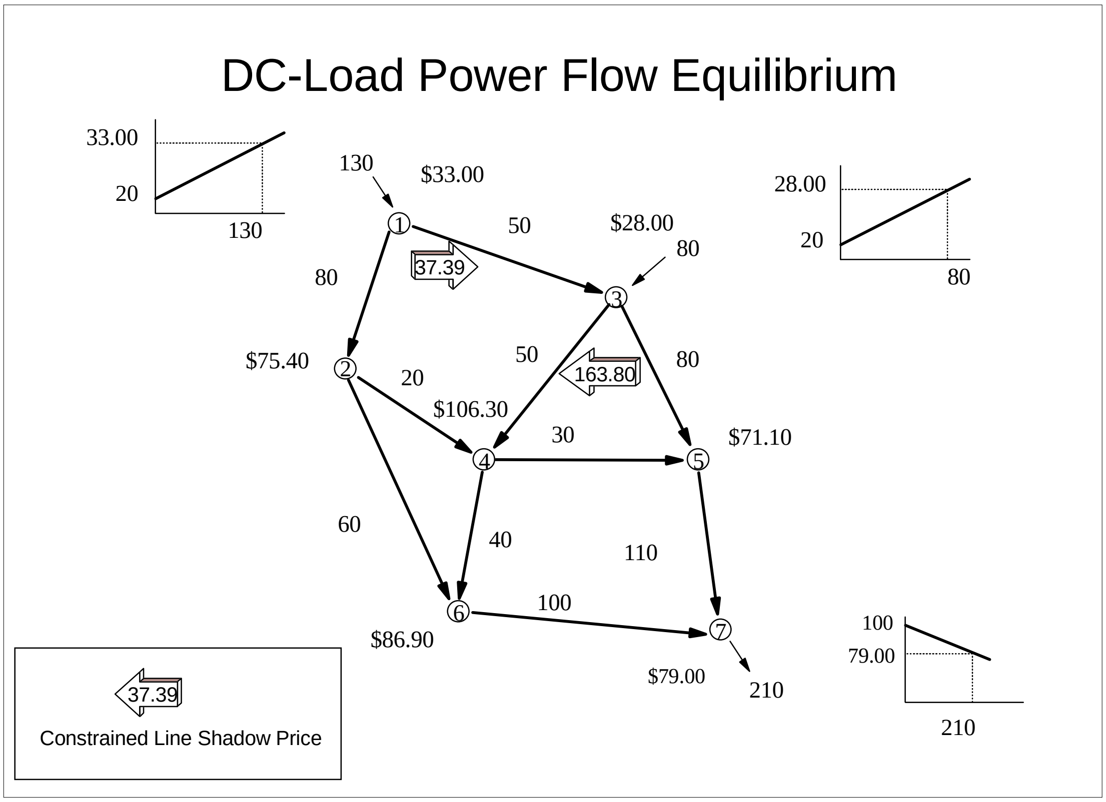
[59] Hung-po Chao and Stephen Peck, "An Institutional design for an Electricity Contract Market with Central Dispatch," The Energy Journal, Vol. 18, No. 1, 1997, p. 96.

flowgate rights matching all the schedules in the example. The injections of power at bus 3 to meet load at bus 7 would provide a counterflow in the example of 15 MW from bus 3 to bus 1. In the example, this counterflow allows the scheduling of injections of 130 MW at bus 1 to meet load at bus 7, without violating the transmission limit on the line from bus 1 to bus 3. This schedule would not be feasible, however, under a system of pure option flowgate rights. This is because the holding of 15 MW of flowgate rights from bus 3 to bus 1 would not provide 15 MW of counterflow rights from bus 1 to bus 3. Not only would the flowgate rights from bus 3 to bus 1 only be options, not obligations, but in the flowgate model the flowgate from 3 to 1 would be distinct from the flowgate from 1 to 3. Hence, the most that could be scheduled and hedged would be 100MW from bus 1 to 7, even if the same entity submitted a schedule for 80MW from bus 3 to bus 7.



The obvious resolution would be to allow for simultaneous credit for the counterflow created by the input of 80 MW at bus 3 which induces 15 MW to flow on the flowgate from bus 3 to bus 1. This would increase the effective capacity, but it would also take us into the realm of making the counterflow an obligation as in the mixed option and obligation approach. The available capacity under the pure option model of flowgates is less than the available capacity under the mixed option and obligation approach. The mixed option and obligation approach with its associated trading rule requires acquisition of the counterflow obligations on all the flowgates induced by a point-to-point schedule. And real schedules are point-to-point, not independent flows on flowgates.

Similarly, the price exposure is different for the hedger. If there is a price reversal from that expected between two locations, then there should be a general reversal of pattern of flows and necessarily on the constrained flowgates. In the actual dispatch, the payments will be for all of the congestion on all of the flowgates. But in the pure option model the reversal of flows would mean that a different set of flowgate rights would apply and the original set of option rights in the opposite direction would not be relevant. In other words, the ability to construct an exact hedge in a transaction under the pure option flowgate model depends on the prices all being positive on the flowgates that match the flow. If the prices reverse, so must some of the flows on the flowgate lines, and the payments for congestion of the point-to-point schedule no longer match the compensation payments under the flowgates rights that match the schedule.

Under the pure option model the imperfect hedge would always be such that the net congestion payments are zero or negative. In the example, the congestion charge between bus 3 and bus 7, would be $51, but the FGR payments under the pure option model would be would be $58. Hence, the option value. However, this anticipated option value would presumably be incorporated in the ex ante market price of the option. As a result, an exposure to the positive or negative risk relative to the expected value of the pure option right would remain. The hedger under the obligation FTR could obtain ex ante price certainty under the LMP/FTR model. The hedger under the pure option flowgate model would have a transmission right with total price determined by a known ex ante payment for the option and an uncertain revenue that would be determined ex post. Hence, contrary to the claims of the flowgate proposals, the pure option version of the flowgate model would not provide price certainty for transmission hedges.

By contrast, the mixed option and obligation model for the FGRs would provide the exact hedge through the matching portfolio of flowgate rights. However, the mixed option and obligation flowgate model analyzed by Chao and Peck provides the hedging transaction with this certainty precisely because for the hedger the FGRs are obligations, required on all flowgates, to and fro, with payments back and forth depending on the direction of congestion on the flowgates: "The trading rule specifies the transmission capacity rights that traders must acquire in order to complete an electricity transaction. … Specifically, a contract to transfer q_{kl} units of power from node k to node l requires a bundle of transmission capacity rights $\{\beta_{ij}^{kl} q_{kl} \mid 1 \le i, j \le n\}$. The transmission congestion rent equals $\sum_{i=1}^{n} \sum_{j=1}^{n} \pi_{ij} \beta_{ij}^{kl} q_{kl}$, which may be either positive or negative, depending on the magnitudes of β_{ij}^{kl} and the prices of transmission capacity rights, π_{ij}."[60]

Hence, the interpretation of the FGR as an option is more complicated in the theory of the mixed option and obligation flowgate model that is always cited as the theoretical template for the flowgate proposals. From the perspective of the speculator, you could obtain an FGR in one direction on a flowgate and not the other. If you did nothing, there would be no further payments, and in this sense it is an option. However,

[60] Hung-po Chao and Stephen Peck, "A Market Mechanism for Electric Power Transmission," Journal of Regulatory Economics, Vol. 10, No. 1, 1996, pp. 36, 39. Here the β_{ij}^{kl} are the distribution factors.

at some stage a transaction in the market would make these FGRs obligations. For example, if a speculator wanted to sell more rights on a flowgate in one direction by offering counterflow on the flowgate in the other direction, the counterflow would become an obligation. Some such counterflow offers would be necessary to achieve full utilization of the grid and the equilibrium solution. Furthermore, for the hedger who ultimately takes the FGR to delivery, the right is inherently an obligation as required by the trading rule. Hence, at some stage all FGRs that have value in the final efficient equilibrium solution appear to be obligations.

In the efficient equilibrium solution, therefore, the only FGRs that are formally options would also have no value and no exposure. The rights that have been traded and ultimately matched with schedules would be obligations.

By comparison, the FTR obligation between two locations would be like a portfolio of FGR obligations with the full commitment to the counterflow effects. The FTR option would be like a portfolio of individual flowgate rights as obligations that could be optional as a portfolio, but not as individual flowgate options. Because of the interactions of this portfolio with others, the feasible combinations would require coordinated evaluation and auction. All the FTR obligations and options could be exercised. By contrast, under the flowgate assumptions, the FGRs do not require coordinated evaluation for feasibility. But not all the FGRs could be exercised.

For both FGRs and FTRs, creation of options and obligations would give the market greater flexibility, as long as both options and obligations could be accommodated without sacrificing efficiency or creating new externalities. Likewise, selling shares in the excess congestion rental collections could provide another vehicle to help address the impacts of unanticipated changes in patterns of use and prices. The point is not that options or obligations are good or bad. The point is that in the flowgate proposals, the details are more complicated than asserted and in the flowgate analysis of the efficiency of decentralized trading the flowgate rights are really obligations, not options.

The risks for speculative holdings of flowgate rights would be different than those holdings for the flowgate hedges. However, if the policy problem is to develop a market design to reduce the risks of speculators it would be helpful to analyze the policy issues in these terms. The primary goal of the LMP/FTR framework has been to provide the equivalent of capacity reservations in a context where the actual physical delivery might be foreclosed by complex network interactions. The FTRs provide just such point-to-point capacity reservations, albeit in financial terms.

Apparently the obligation version of the flowgate right would be necessary to construct the same hedge for the flowgate model as in the FTR model. Furthermore, the obligation version of the flowgate model would be necessary to achieve full utilization of the capacity of the network.

COMMERCIAL FLOWGATE MODEL

This critique of the flowgate model suggests that it would not be an appropriate model for operating the power system. And we have not even considered here the interactions with market power or the incentives for transmission expansion. The flowgate assumptions are not true, at least not to the degree that we can rely completely on the flowgate model. In other words, the literal equivalence between the result of flowgate trading and the result of the LMP/FTR market is upset by the approximations in the flowgate model.

The real flowgate proposals recognize these disconnects and approximations in several ways. First, as mentioned above, the flowgate rights are slowly migrating from a purely physical model where rights are necessary to schedule and deliver power to a financial model where schedules and dispatch are not constrained by the rights, with the FGRs determining some form of compensation. Second, the more detailed flowgate proposals confront the need for a real-time balancing market coordinated by the system operator based on the voluntary bids of the market participants. Third, the flowgate proposals recognize that the full capacity even of the flowgates would not be known in advance, and the idea is to issue initially only conservative amounts of rights to reserve the capacity of the system that varies with the load conditions. Further, the RTO should enter the business as an active trader to take short and long positions to continuously rearrange the outstanding FGRs to make them closer to reality.

These details are not universal in the flowgate proposals, but it is the trend and there are good reasons for each of these accommodations. However, these modifications of the pure flowgate design raise many other questions, some mentioned above and others more fully developed by Ruff. [61] The leading answer to many of these criticisms is to minimize their importance. For example, as to the problem of flowgates that are not identified as commercially significant in advance, but cause congestion in the real dispatch, the response is to dismiss the importance of the problem by arguing that the non-flowgate congestion will be "low." Or if the cost is not low, then it will be easy to add to the list of commercially significant flowgates. [62] Those who have participated in the agony of changing zonal pricing models, where the same arguments were made, might be less sanguine about this ability to fix what is broken, rather than trying to avoid the design problems from the start. [63]

In effect, the arguments in favor of the flowgate proposals no longer stand on the assertion that the flowgate model produces the same market equilibrium, but rather that the differences in the flowgate schedules and the efficient real use of the system will be negligible. In effect, *I* think the risks are small, so *you* should bear them. However, if one differs in the view about the magnitude of the risks, the view of the difficulty of fixing what is broken, or the view of the problems down the road for a fully specified flowgate model, one might also differ in a judgment about which entity should bear the risks and about the best policy for rules to be set down by the monopoly RTO and the associated system operator.

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[61] Larry E. Ruff, "Flow-Based Transmission Rights and Congestion Management: A Comment," San Francisco, CA, July 22, 2000.

[62] Tabors Caramanis & Associates, "Real Flow A Preliminary Proposal for a Flow-based Congestion Management System," Cambridge, MA, July 18, 2000, p. 8.

[63] William W. Hogan, "GETTING THE PRICES RIGHT IN PJM. Analysis and Summary: April 1998 through March 1999, The First Anniversary of Full Locational Pricing," April 2, 1999, available through the author's web page.

The critique would be less applicable to a commercial model that would serve as an entrepreneurial business. Suppose that the criticisms of the flowgate assumptions are correct as a literal matter and we could not use the flowgate model to operate the system. However, suppose the commercial significance of the cleanup is small. Inherent in this argument is that there would be no market failure of any commercial significance. Hence, there would be no need for the RTO to do anything further to address any market failure. The RTO could operate the coordinated dispatch and define financial transmission rights as outlined above for the real system rather than the flowgate approximation. Although it is not possible to identify all the capacities and distribution factors of the flowgate model in advance and without knowing the flows, it is possible to determine in advance if a particular load flow would be feasible for a given configuration of the grid. Hence, despite the complexity of the grid, a set of simultaneously feasible point-to-point financial transmission rights could be defined. For a given configuration of the grid, the RTO could guarantee the payments under the point-to-point FTRs without using its powers to tax the participants and socialize the costs.

Under the simplifying assumptions of the flowgate model, it would be possible to decompose these point-to-point financial transmission rights into their component commercially significant flowgates, implied flow capacities on flowgates, and the associated distribution factors. If the approximation errors of the flowgate model were not large, then it would be possible for a private commercial business to provide the service of organizing trading of flowgate rights that could be reconfigured to create new FTRs. The differences in flows and capacities might be small, most of the time, and the occasional excursions would not be commercially significant. Or, to be more precise, under these assumptions the occasional excursions would not be significant as long as the system operator did not socialize the costs.

Under these circumstances, there is a clear business opportunity. The RTO need not and should not do anything different than outlined above as part of the essential market design.[64] Appealing to the very argument advanced often in flowgate proposals, the RTO should not take on any additional responsibility:

> "…we recall a well-known folk theorem in economics suggesting that in the absence of market failures (i.e., externalities in the present case), whatever a central agency can do, a market can do better. Thus a corollary is that once the main cause of market failure is fixed, market forces could be relied upon for efficient self-organization." [65]

This counsel was applied to a recommendation to use flowgate rights to define the constraints and allow self-organization to construct the point-to-point FTRs. However, as we see, this depends on the assumptions of the flowgate model and the externalities it

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[64] For hedges on the flowgate capacities that were not fully required in the point-to-point financial rights, the RTO could auction off rights to excess congestion revenues from reconfiguration of the FTRs. As needed, there could be additional coordinated reconfiguration auctions. For example, PJM provides month-ahead and day ahead coordinated auctions.

[65] Hung-po Chao and Stephen Peck, "An Institutional design for an Electricity Contract Market with Central Dispatch," The Energy Journal, Vol. 18, No. 1, 1997, p. 99.

would create. If the assumptions are wrong, the FTRs are better at internalizing the externalities. And if the flowgate assumptions are right, efficient self-organization could construct the commercially significant flowgates.

Within this framework, an entrepreneur would be free and able to set up a business that provided the flowgate service, charging participants for the claimed benefits and providing a revenue stream to compensate for the small risks involved. In effect, the business could take the financial risk that the reconfigured FTRs might not be feasible in the real network, but if the flowgate assumptions were valid this risk would be small. But then if *I* the entrepreneur think the risks are small, *I* not *you* would bear them, who might disagree.

The appendix outlines further details of such a commercial flowgate model where the risks of the flowgate approximations would be accepted by those who endorse and use these approximations. This is one way to have it both ways, to include both the LMP/FTR model and the flowgate model. Ideally it would be desirable to find a way that would allow the RTO to do both without creating any risks as a result of the approximations. However, if the assumptions in the flowgate model are seriously wrong, and the risks are significant, there may be no risk free way to have both FTRs and FGRs. The easy argument that the flowgate rights can be combined to produce the same effect as the LMP/FTR model is based on the foundation of the flowgate assumptions. If the foundation is flawed, so is the argument. The commercial flowgate model may be the best approach to avoid the perverse effects of subsidizing the mistakes.

When viewed from this perspective, the arguments in favor of the flowgate approach should not be seen as applying to the RTO. When the RTO follows this path, trouble is likely to appear because the real system is more complicated. Rather, the arguments for the flowgate approximation should be seen as either wrong or right. If wrong, they should be ignored. If right, they should lead to a successful business. But the flowgate model is likely to be a problematic market design for an RTO.

CONCLUSION

The complex interactions in electric networks present special problems for the operation of competitive markets. When market participants have choices, simplified models of the real system can create externalities and perverse incentives that could be and have been relentlessly exploited by profit seeking entities seeking the very profits that are at the core of the theory of the competitive model. Hence, it is more important to get the get the prices right than it is to make everything simple. The flowgate model includes a number of simplifying assumptions. By now it is clear that the simplifying assumptions are not literally true. The argument is that the costs of deviation are small and the benefits are large. A striking feature of this argument is that if it were true then there would be a commercial opportunity to create flowgate trading without upsetting efficient pricing in the more complex reality managed by the system operator. The apparent contradiction of the flowgate proposal for a centralized monopoly to get deeply into this business of a supposedly simple and low risk forward trading market raises serious questions about the creation of yet another set of subsidies and perverse incentives. The echoes of the arguments for zonal pricing are heard in the same arguments applied to flowgate proposals. Centrally mandated zonal pricing models have failed as predicted. If the flowgate model would work so well, why isn't voluntary commercial implementation the innovation of choice?

APPENDIX

Conducting Decentralized Commercial Forward Markets for Flowgate Rights in Concert with LMP-Based Real-Time Markets for Balancing and Congestion Management

August 3, 2000[66]

Development of effective commercial forward markets for electricity should yield a number of benefits. While supporting the commercial activities of electricity market participants, these markets could also facilitate advance scheduling, which would simplify the task of operating coordinated real-time markets for balancing and congestion management. However, it will still be necessary to operate these real-time markets, and if these markets are not conducted properly, they could undermine the ability of forward markets to operate efficiently, as they could give market participants incentives to evade the forward markets and transact in real time instead. A real-time market for residual balancing and congestion management that is based on locational marginal pricing (LMP), in which market participants submit voluntary bids to provide balancing services and prices for balancing are calculated that are consistent with those bids, provides the support necessary for forward markets to function efficiently. With such real-time markets in place, forward markets can operate as commercial ventures that permit reliability to be maintained and that do not require socialization of costs.

Overview

- Initially, MISO could choose not to operate forward markets, but it would provide forward (day-ahead) procedures for scheduling transactions.

- Private commercial entities could offer forward flowgate rights (FGRs) and provide scheduling services for those who wished to trade through these commercial entities. Each such entity would define the terms for the FGRs it issues.

- Any entity would be permitted to schedule transactions with the MISO.

- The MISO would provide technical information as requested about network configuration and system conditions (e.g., flowgate distribution factors) to facilitate commercial forward markets.

[66] This version of a commercial flowgate model was developed by Michael Cadwalader and John Chandley as a submission for the discussions organized in support of the Midwest Independent System Operator.

- The MISO would balance the system and manage congestion in real time using LMP, using bids voluntarily submitted by market participants.

- The MISO would offer financial transmission rights (FTRs) between locations, which hedge against locational differences in real-time LMPs, providing one mechanism through which market participants could obtain advance price certainty.

- The entities offering scheduling services to holders of the FGRs they have issued could acquire FTRs in order to hedge the real-time LMP costs associated with the transactions they schedule.

How FGR Systems Could Function within MISO

The outline below of the details of the commercial forward market for flowgate rights (FGRs) and the MISO-coordinated real-time market for balancing and congestion management highlights the main features of each, what each is responsible for, and how the operation of each affects the other. For the most part, private commercial entities that wish to offer FGRs would define the rules under which they operated, subject to the overall scheduling and settlement rules defined by the RTO. The details here illustrating the options available to FGR holders are meant to be illustrative, not prescriptive.

- Private commercial entities could offer FGRs.

  - ♦ If a market participant acquired the "correct" portfolio of FGRs, as defined by the entity issuing the FGRs (the "FGR Issuer"), the FGR Issuer would assume responsibility for ensuring that the transaction is scheduled, and for paying all congestion costs associated with transactions it schedules with the MISO.

  - ♦ Each FGR Issuer would make the following determinations for the FGRs it issues:

    - ▪ Which transmission facilities it designates as flowgates (i.e., which it or its customers deem to be commercially significant).

    - ▪ What procedure will be used to determine the portfolio of FGRs required to schedule each transaction.

    - ▪ The number of FGRs it will issue across each flowgate.

    - ▪ The areas in which entities can schedule transactions with the FGR Issuer.

    - ▪ Whether entities scheduling transactions with the FGR Issuer are required to obtain FGRs across all flowgates that are affected by their transactions.

    - ▪ How the FGR Issuer will settle with those entities, in case the FGR Issuer does not require entities scheduling transactions to have FGRs across all flowgates that are affected by a transaction.

    - Whether the FGRs it issues will be options or obligations. (It could also issue both.)

    - Whether the FGR Issuer will issue FGRs to entities that schedule counterflow transactions across flowgates.

  - Each FGR Issuer would also:

    - Be responsible for determining how the FGRs it issues would be priced, as well as any other charges for the services it provides.

    - Determine whether buyers of its FGRs could trade them bilaterally, or in FGR Exchanges that are operated by, or independently of, the FGR Issuer.

    - Set up its own FGR Exchange, if it wishes to do so.

    - Determine whether and when to repurchase flowgate rights in order to ensure the feasibility of the FGRs it issued, and determine the amount it would pay for any repurchased rights and how it would recoup those costs.

  - There could be multiple FGR Issuers. Each FGR Issuer would make the above determinations for itself.

  - The MISO would not be an FGR Issuer.

    - This avoids needless competition with private FGR Issuers, and ensures that the MISO does not incur costs for congestion management (on transmission constraints that have not been designated as flowgates, for example) that it then socializes over all market participants.

    - In contrast, private entities that are FGR Issuers would be free to recover their costs however they like. They may average congestion costs over their customers as they see fit, since their customers would be free to leave if they do not like it.

- FGR Issuers and other entities schedule transactions with the MISO.

  - Each FGR Issuer would submit schedules to the MISO reflecting all transactions that have been scheduled with that FGR Issuer.

  - Other entities that are not FGR Issuers would also be permitted to submit schedules to the MISO. There would be no requirement for an entity to hold FGRs issued by any FGR Issuer in order to schedule a transaction with the MISO.

  - Schedules submitted by any entity need not be balanced (i.e., there will be no requirement that total injections submitted by an entity equal total withdrawals scheduled by that entity). Therefore, each FGR Issuer would be free to submit balanced schedules to the MISO, but would not be required to do so.

- Any entity submitting a schedule could also submit bids indicating the LMP below which the MISO may direct their generation to decrease output (or loads to increase consumption), or the LMP above which the MISO may direct their generation to increase output (or loads to decrease consumption). These bids may cover some or all of the capacity of some or all of the generators or loads being scheduled by that entity.

- Alternatively, each entity submitting a schedule could elect to submit a fixed schedule (without bids) for part or all of the generators and loads it is scheduling**.**

What the MISO RTO Would Do

- The MISO would accept schedules for all transactions within, into, through or out of the MISO-controlled grid.

- The MISO would balance the system and manage congestion in real time using LMP.

  - The MISO would accept voluntary bids from generators and loads and would use those bids to coordinate a real-time security-constrained economic dispatch, subject to the coordination abilities between the MISO system operators and those of participating control areas. This regionally-coordinated dispatch would balance the system while honoring all constraints managed by the MISO system operators, and do so at the least as-bid cost given the available bids.

    - The degree of coordination between the MISO and existing control area operators would be determined based on the operational abilities of the MISO, economics, and other practical considerations.

  - Within this coordinated framework, MISO would balance the system using only the generators and loads that have submitted bids, including those entities with schedules that indicated through adjustment bids that they are willing to deviate from their schedules, and the prices at which they are willing to deviate. All other schedules would be fixed.

  - Its objective when balancing the system would be to do so at the least bid cost possible while maintaining system reliability.

  - When balancing the system, the MISO would only take into account those constraints that have been turned over to the MISO for management by individual control area operators.

  - The LMPs that MISO calculates would be based on the marginal bid cost of dispatching generation (and load) to meet an increment of load at each location on the system, while ensuring that the transmission constraints being managed by the MISO are not violated in any monitored contingency.

- All schedules and deviations from schedules would be settled at real-time LMPs.

    - ♦ Each entity that submitted a schedule to transmit energy from one location to another would be charged a congestion (or usage) charge to reflect the MISO's marginal cost of redispatching the system to accommodate the schedule. This congestion charge would be calculated by subtracting the real-time LMP at each location where power was scheduled to be injected from the real-time LMP at each location where power was scheduled to be withdrawn for each MW of power included in that schedule.

        - ▪ Consequently, FGR Issuers would be responsible for paying any congestion charges (marginal redispatch costs), based on the difference between the real-time LMPs at the injection and withdrawal locations for each transaction they schedule.

    - ♦ Each entity that submitted a schedule whose actual generation deviated from these schedules would be paid the real-time LMP at the location of that generation (if they generated more power than scheduled) or would pay the real-time LMP at the location of that generation (if they generated less power than scheduled).

    - ♦ Entities whose actual load deviated from these schedules would be paid the real-time LMP at the location of that load (if they consumed less power than scheduled) or would pay the real-time LMP at the location of that load (if they consumed more power than scheduled).

        - ▪ If an FGR Issuer elected to submit bids for transactions that have been scheduled through them, and the MISO re-dispatched generation or load whose bids were submitted by that FGR Issuer, settlements between that FGR Issuer and the re-dispatched generator or load would be contractual issues between those parties.

    - ♦ LMPs would be determined at each node. Generators would be settled at their respective nodal LMPs. Whether LMPs for loads are calculated on a nodal or a zonal basis would depend upon metering and software. Settlements for loads without appropriate metering would be based on zonal prices, defined as the load-weighted average of the nodal prices within the region defined as the zone. Initially, such zones could reflect existing utility control or franchise areas.

- MISO would offer FTRs well in advance to allow participants to hedge congestion costs and obtain advance price certainty.

    - ♦ Each FTR would specify an injection location and a withdrawal location.

    - ♦ The holder of an FTR would be paid an amount equal to the LMP for 1 MW at the FTR's withdrawal location, minus the LMP for 1 MW at the FTR's injection location, in each hour in which the FTR is valid, regardless of whether they undertake physical transactions matching those FTRs.

- Contingent upon investigation of certain technical issues, FTRs would be offered both as obligations (which would require the FTR holder to make a payment when the LMP at the FTR's injection location is greater than the LMP at the FTR's withdrawal location) and as options (which would not require a payment from the FTR holder in such circumstances).

- Certain FTRs would be allocated to certain entities in order to settle pre-existing obligations of the TOs to transmit power at a price certain. The remaining FTRs would be allocated through periodic auctions. The MISO would ensure that the total set of FTRs is simultaneously feasible (i.e., that transactions corresponding to the complete set of FTRs did not cause overloads of any transmission facilities in any contingencies monitored by the MISO).

- FGR Issuers could acquire FTRs in order to hedge the congestion costs they incur in order to schedule transactions. For example:

  - If an FGR Issuer determines that an injection of 1 MW at location X and a withdrawal of 1 MW at location Y causes 0.5 MW to flow over flowgate A and 0.2 MW to flow over flowgate B (and there are no transmission constraints other than these two flowgates), then an FTR from X to Y corresponds to a portfolio of 0.5 MW of FGRs over flowgate A plus 0.2 MW of FGRs over flowgate B (given a particular network topology).

  - Thus, if an FGR Issuer were to purchase an FTR from X to Y, it would be hedged against the cost associated with offering 0.5 MW of FGRs over flowgate A and 0.2 MW of FGRs over flowgate B, as long as the relevant network topology does not change.

  - A perfect match between FTRs and FGRs would limit the number of FGRs offered across a flowgate to that flowgate's physical capacity, because the number of FTRs that can be defined is limited by the system's transfer capability (via the simultaneous feasibility test); hence the number of FTRs that FGR Issuers can acquire to hedge their position will also be limited by the system's transfer capability. However, if FGR Issuers wanted to issue FGRs across a flowgate that are not backed through FTRs, they would be free to do so.

- Entities that are scheduling transactions but are not FGR Issuers could also acquire FTRs, in order to hedge the congestion costs associated with the transactions they schedule.