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Transmission Market Design

William W. Hogan

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TRANSMISSION MARKET DESIGN

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Electricity Deregulation: Where to From Here?
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William W. Hogan

Center for Business and Government
John F. Kennedy School of Government
Harvard University
Cambridge, Massachusetts 02138

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TRANSMISSION MARKET DESIGN

William W. Hogan[i]

Coordinated electricity spot markets support open access to existing transmission grids. Associated financial transmission rights provide a key ingredient for long-term contracting and property rights for grid expansion. Design of a mixed system of merchant and regulated transmission investment presents a challenge for regulators and market participants. With the right choice, merchant transmission investment could play a significant but not exclusive role in efficient transmission expansion. With the wrong choice, the unintended consequences could undermine the whole foundation of electricity market restructuring.

> "The Commission proposes to provide new choices through a flexible transmission service, and an open and transparent spot market design that provides the right pricing signals for investment in transmission and generation facilities, as well as investment in demand reduction." [1]

INTRODUCTION

Transmission policy stands at the center of electricity market design. The special complexities of electric power transmission require nothing less than a paradigm shift in order to support a restructured competitive electricity market. The change in perspective is captured in the seeming oxymoron of "coordination for competition." Unlike for other commodities, successful electricity markets require new institutional infrastructure with a visible hand to support competition. Given a coordinated spot market with consistent pricing, most decisions can be left to market participants. Building on this spot market design, it is possible to create new forms of property rights and allow private responses to price incentives to drive most operating and investment decisions.

Reliance on market participants to make most or all investment decisions for generation and demand alternatives seems both natural and much like other normal markets. Extending this same policy to the realm of transmission investments is less obviously easy and may in some cases be problematic. The result has been a growing controversy about the relative roles of merchant and regulated transmission investment, and about the implied proper policy for the transmission investment part of the overall electricity market design.

The purpose here is to summarize the main developments that build on a coordinated spot market and point to the use of market incentives to facilitate transmission investment. The focus is on a line of argument that points to a critical choice that must be made for transmission investment policy, drawing a line between

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1 FERC SMD NOPR, July 31, 2002, p. 3.

merchant and regulated investment. The choice could reverberate throughout the rest of electricity market design. With the right choice, merchant transmission investment could play a significant but not exclusive role in efficient transmission expansion. With the wrong choice, the unintended consequences could undermine the whole foundation of electricity market restructuring.

STANDARD MARKET DESIGN

The core elements of the Federal Energy Regulatory Commission's (FERC) Standard Market Design Notice of Proposed Rulemaking (SMD NOPR)[2] target the essential requirements for a competitive electricity market.[3] The twin principles of open access and non-discrimination require fundamental change in the rules and organization of the electricity system. When coupled with the objective of achieving an economically efficient electricity system, these principles lead inexorably to the requirements for a standard market design. Standardization is important for the obvious effect of reducing "seams" issues between regions and markets. Less obviously, but even more importantly, certain critical market activities require standardization in order to support efficient operation with open access and non-discrimination in an electricity market.

The market cannot solve the problem of market design. The FERC provides an accurate description of the problems inherent in the large externalities of transmission usage and a sound solution in the application of the necessary coordination in support of a market. In each region, an Independent Transmission Provider (ITP) must administer a single tariff and operate the transmission system to support certain essential services. The critical centerpiece of the design is a coordinated spot market for energy and ancillary services. This spot market employs the framework of a bid-based, security-constrained, economic dispatch with locational marginal cost pricing (LMP). The framework includes bilateral contracts with a transmission usage charge for each transaction based on the difference of the locational prices at the points of input and withdrawal.

This centerpiece of the SMD framework builds on the analysis found in FERC's previous orders on Regional Transmission Organizations (RTOs) and supports additional features such as financial transmission rights and license plate transmission access charges. A good design for the spot market can facilitate long-term bilateral contracting or support market participants self supplying to meet their own loads, arrangements that could constitute the bulk of energy transactions. Given the incentives from locational pricing, there is a natural market stimulus to sustain generation and demand-side investments. In addition, the creation of financial transmission rights provides further opportunities and incentives for market participants to undertake transmission expansion.

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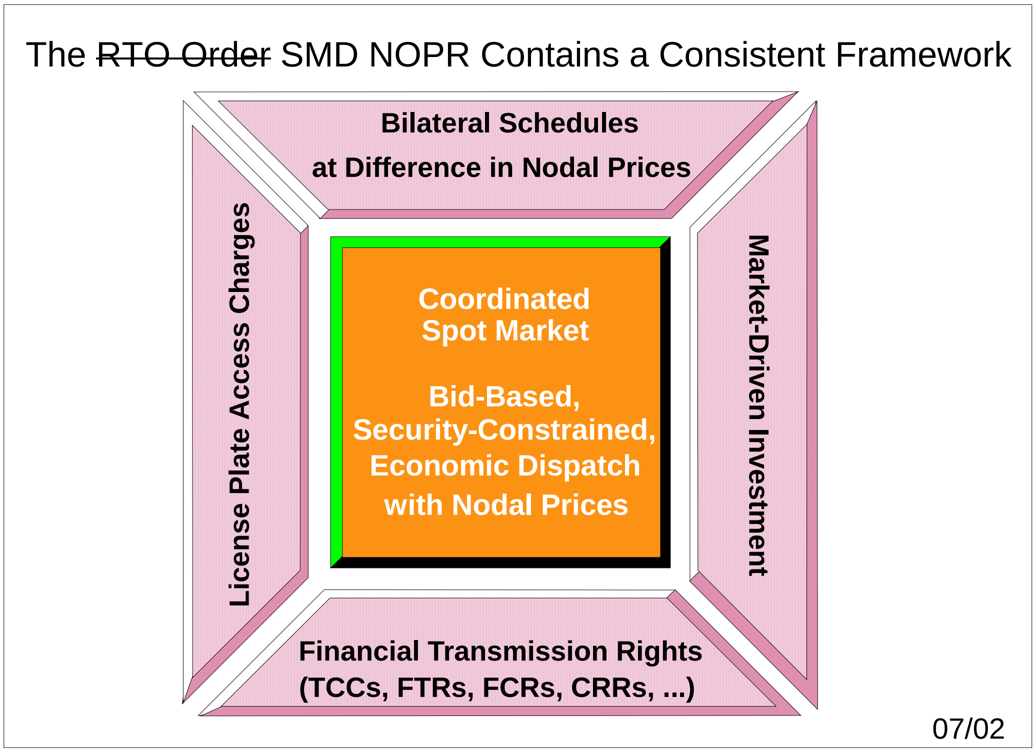
[2] Federal Energy Regulatory Commission, Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design, Notice of Proposed Rulemaking, Washington DC, July 31, 2002.

[3] For a more extended commentary on the core elements of the SMD NOPR, see John D. Chandley and William W. Hogan, "Initial Comments on the Standard Market Design NOPR," Docket No. RM01-12-000, November 11, 2002, p. 56.



At great expense, the United States has gone through an extended period of experimentation with designs for market institutions for the electricity system. There have been notable successes, as in the Eastern Independent System Operators (ISOs)[4], as well as notable failures.[5] These experiments have been punctuated by major decisions by the FERC that advanced the development of an open access regime and efficient electricity markets. However, faced with sharply conflicting views across the industry, FERC's vision had not previously been sufficiently complete or clear.

The notable failures in electricity markets brought the nation to a crossroads in electricity restructuring, with some voices urging a halt or retreat out of fear that the failures will be replicated elsewhere. Learning from these failures is essential, but turning back would be the wrong lesson, and standing still is not tenable. The FERC must move forward with the core elements of SMD. The nature of the electricity system requires an ITP's visible hand to coordinate the markets and assure reliability.

By now, the costly experiments have made plain that certain fundamentals are necessary for a successful electricity market. These are the elements at the core of the SMD framework, and the elements often absent in the failed experiments. An independent entity operating with the protocols of a coordinated real-time spot market

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[4] The ITP is the new name for the ISO, or the RTO. There are differences in meanings, but here we treat the terms as interchangeable.

[5] William W. Hogan, "Electricity Restructuring: Reforms of Reforms," Journal of Regulatory Economics, January 2002, Vol. 21, Issue 1, pp. 103-132.

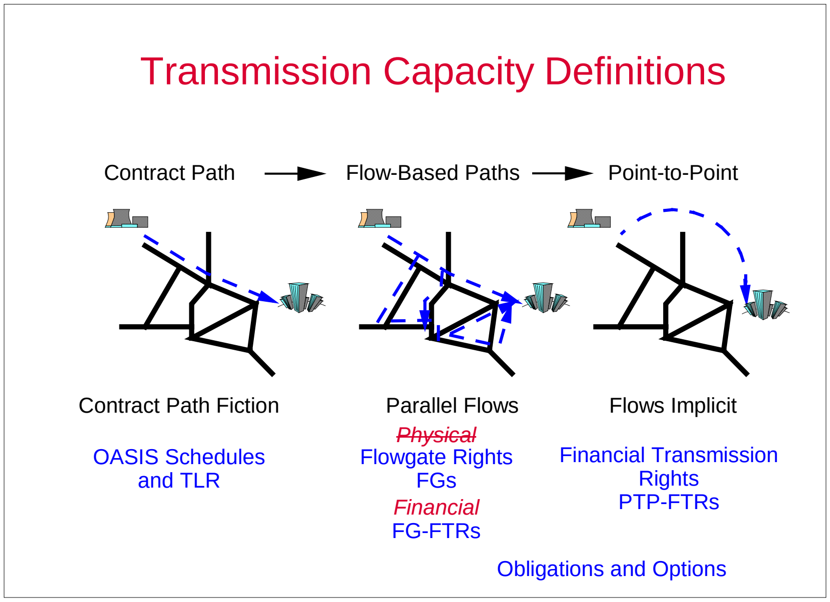
with consistent locational pricing to reflect the actual limitations of energy availability and transmission constraints is first among these necessary elements. This by itself is not sufficient for a successful energy market. But we know from both theory and experience that it is necessary.

This core market design includes financial transmission rights as a central element playing a role in protecting economic uses of the existing grid and providing a foundation for transmission investment.

FINANCIAL TRANSMISSION RIGHTS

Given the core elements of the SMD structure, the natural definition of transmission rights is financial and closely related to the net revenues collected by the system operator in the balancing and short-term transmission market. In the presence of electrical losses and congestion, the revenues collected under an LMP model would be greater than the payments to participants. This net revenue is sometimes referred to as the merchandising surplus, congestion rent or other similar terms. More precisely, under the framework of bid-based, security-constrained, economic dispatch the net revenue difference is simply the inframarginal rent on losses and transmission constraints. This source of revenue is critical in designing and understanding the nature of financial transmission rights (FTRs).[6]

There has been a great deal of debate about the nature of transmission rights, starting with the fictional contract path and ending with FTRs. It is to be hoped that the SMD NOPR marks the conclusion of that costly and sometimes confused conversation. In its most turbulent stages, there were many attempts to argue that transmission rights should be defined as "physical," meaning that somehow the actual flow of power



[6] The many FERC orders and market designs have produced a proliferation of terms for essentially the same ideas. In the case of financial transmission rights, which might include the effect of losses, we have a generic name. These are very similar to Congestion Revenue Rights (CRR) and Transmission Congestion Contracts (TCC). For most purposes here, the terms are interchangeable.

would be constrained by the rights acquired, and schedulers would have to match the schedules and rights. The hope was that these physical rights would provide the mechanism of coordination rather than the coordinated spot market of the system operator. In the real system, this would be simply unworkable. Hence, other common proposals have been to socialize some or all transmission congestion costs in order to make it possible to ignore the real network and define simple transmission rights divorced from reality. Inevitably, the socialization of costs would create perverse incentives in a market. It took a while, but at least for the moment these ideas appear to have fallen of their own weight.[7]

As the debate moved beyond these unworkable physical models, there was an extended discussion about the nature of different financial transmission rights. Here too we find more than a little confusion lingering in the conversation. Although the details can be important, particularly when dealing with losses and unbalanced rights, for the present discussion, it is possible to reduce the choices to the elements of a simple two-by-two matrix. A cursory summary of a much more extensive analysis of FTRs provides the backdrop for a discussion of the rules for transmission investment.[8]

The starting point is the bid-based, security-constrained, economic dispatch problem:

$$\begin{aligned}
&\underset{d,g,y,u\in U}{Max}\; B(d)-C(g)\\
&s.t.\\
&\quad y=d-g,\\
&\quad L(y,u)+\iota^t y=0,\\
&\quad K(y,u)\le 0.
\end{aligned}\tag{1}$$

Here the vector $y=d-g$ is the net load at each location, the difference of demand and generation. The variables in U represent various controls used by the system operator. The objective is the bid-based net benefit function as the difference in the bid-benefit for demand and the bid-cost for generation. The constraints balance actual losses L and net load $\iota^t y$. The (many) contingency limits define the security constraints in K. The constraints are a complex function of transmission flows and other factors.[9] The corresponding multipliers or shadow prices for the constraints would be (p,λ,η) for net loads, reference bus energy and transmission constraints, respectively.

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7 For a further discussion, see William W. Hogan, "Flowgate Rights and Wrongs," Center for Business and Government, Harvard University, August 2000. Larry E. Ruff, "Flowgates, Contingency-Constrained Dispatch, and Transmission Rights," Electricity Journal, Vol. 14, No. 1, January/February 2001, pp. 34-55.

8 For a further discussion, wee William W. Hogan, "Financial Transmission Right Formulations," Center for Business and Government, Harvard University, March 31, 2002.

9 For simplicity of exposition, the constraints treat only net loads. Some constraints may have separate effects for load and generation. This would lead to different prices for load and generation at t he same location, but that is not important for the present discussion.

With the optimal solution (d^*, g^*, y^*, u^*) and the associated shadow prices, we have the vector of location prices p as:

$$p^t = \nabla B\left(d^*\right) = \nabla C\left(g^*\right) = \lambda \iota^t + \lambda \nabla L_y\left(y^*, u^*\right) + \eta^t \nabla \tilde{K}_y\left(y^*, u^*\right). \tag{2}$$

Therefore, locational prices equal the marginal benefit of demand, which equals the marginal cost of generation, which in turn equals the reference price of energy plus the marginal cost of losses and congestion.

Financial Transmission Rights

	Point-to-Point	Flowgate
Obligations	$P_{Destination} - P_{Source}$ Demonstrated in PJM, New York	$\sum_k \eta_k f_{fk}^f$, $\eta_k = shadow\ price,$ $f_{fk}^f \begin{matrix} \geq 0 \\ \leq 0 \end{matrix}, the\ flowgate\ amount.$ Too complicated to use?
Options	$\max\left(0, P_{Destination} - P_{Source}\right)$ More complicated to evaluate simultaneous feasibility.	$\sum_k \eta_k f_{fk}^o$, $\eta_k = shadow\ price,$ $f_{fk}^o \geq 0, \quad the\ flowgate\ amount.$ Too complicated to use?

Using this terminology, the alternatives for financial transmission rights consist of four types as shown in the above figure. The column dimensions refer to point-to-point (PTP) and flowgate definitions. The row dimensions refer to obligations and options. Consider first the PTP obligation. Here the FTR for 1 MW applies to a source and a destination, and the holder of the right receives a payment equal to the difference in the prices in the coordinated spot market. The obligation feature refers to the possibility that the payment may be negative. Whether positive or negative, the PTP obligation is a perfect hedge when matched with an actual power flow. The flow is charged at the difference in the locational prices and the FTR pays out the same difference in the prices. If the set of PTP obligations is simultaneously feasible, then there is revenue adequacy in the sense that under mild regularity conditions the net revenues from the actual coordinated spot market would always be sufficient to cover the net payments under the FTRs.[10]

Importantly the PTP definition says nothing about the actual path of the power flow. The definition is the same whether the source and destination are connected by a single line or a complex network. As discussed below, the PTP obligation is inherently simple to implement, and it has been the initial form of FTRs in the successful markets of PJM and New York and is part of the new system in New England.[11]

For loads wishing to hedge purchase contracts with generators, the PTP obligation would be enough. However, for speculators who do not have such a hedging interest, the possibility of negative payments when price is higher at the source than at the destination creates an expressed interest in defining PTP options. In short, an option involves only a positive payment on the FTR, but if prices reverse there is no obligation to pay.

The PTP option is usually the first idea that comes to mind in defining FTRs. It would be natural to wonder why this has not been the first choice in successful markets.[12] Although workable in principle, on closer inspection there are problems with the PTP option. For example, PTP obligations easily reconfigure to support a system of trading hubs, whereas PTP options are inherently point-to-point and difficult to reconfigure. For similar reasons, it is easy to decide on a simultaneously feasible allocation of PTP obligations but much more difficult to decide if a collective allocation of PTP options would be revenue adequate. And by construction the option excludes the effects of counterflow that relieves constraints in the network, so fewer options than obligations would be feasible. Given these complications, the first choice for implementation by the PJM, New York and New England ISOs has been PTP obligations.

Motivated by the attempts to develop physical rights, the flowgate idea can be explained in terms of the pricing equation in (2). Ignoring losses, we see from the definition of locational prices that the difference in prices between locations consists of a particular aggregation of the shadow prices times the gradients of the transmission constraints. In other words,

$$\begin{aligned} p^t\delta &= p_{Destination} - p_{Source} = \eta^t \nabla K_y\left(y^*, u^*\right)\delta, \\ \delta^t &= \begin{pmatrix} 0 & \mathrm{L} & +1 & 0 & \mathrm{L} & 0 & -1 & \mathrm{L} & 0 \end{pmatrix}. \end{aligned} \tag{3}$$

Hence, we could decompose the difference in congestion prices into two parts, the amount of impact in the constraints $\nabla K_y\left(y^*, u^*\right)\delta$, sometimes known as the shift factors, and the shadow prices of the constraints in η. The idea would be to define a "flowgate" amount equal to some ex ante amount f and then to pay the holder of the right according to the shadow prices on the flowgates.

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10 There could be excess revenues, reflecting constraints not binding in the allocation of FTRs. This is not critical to the discussion here.

11 The new market design largely consistent with the SMD NOPR began operation in New England March 1, 2003.

12 A form of option has been implemented without much success, as in California.

In most discussions of flowgates, there is a tendency to think of the flowgate as a transmission line or collection of lines, and the flowgate right is the amount of power that flows over that line. However, in the more sophisticated formulations, each constraint defines a flowgate, and the flowgate right is just the amount of that constraint.[13] If the amount of the flowgate right matches the implied flow of a point-to-point transaction for 1 MW, then

$$\begin{aligned} f &= \nabla K_y\left(y^*, u^*\right)\delta, \\ p_{Destination} - p_{Source} &= \eta^t f. \end{aligned} \tag{4}$$

Under these conditions, the flowgate right would also provide an exact hedge for the point-to-point schedule. However, notice that some of the elements of the vector f may be negative. Even though the shadow prices would be non-negative, the payments could be negative just as with the PTP obligations. Hence, flowgate rights that are positive or negative for a given constraint would be essentially obligations.

The obvious alternative for flowgate obligations would be to select only the positive value for a particular constraint. Then, with the non-negative shadow prices, the flowgate would be an option in the sense that payments would never be negative. Of course, we can see that like the PTP option formulation of an FTR, the flowgate option would then not provide a perfect hedge for a point-to-point transaction.

The consistent formulation of the flowgate rights would define each constraint as a flowgate, but there would be no requirement to match to $\nabla K_y\left(y^*, u^*\right)\delta$ or select all the elements of f. The design would leave it to the market participants to decide on how much of a right to purchase and on which flowgates.

These flexible features are necessary since in all but the most trivial cases it would be virtually impossible to determine ex ante the shift factors that would apply in the actual dispatch at any time in the future. Further, the dimensionality of the shift factors can be enormous. The illustrative examples used in policy discussions always refer to a handful of flowgates, which seems manageable. However, in the complete formulation for a real system, the number of "flowgates" could easily reach hundreds of thousands, reflecting the combinatorial problem of many constraints, with every constraint different in every monitored contingency. Ex post, the actual dispatch would find relative few of these constraints actually limiting, otherwise it would be impossible to solve the dispatch problem. But ex ante we do not know which of the few constraints would be limiting, and the full dimensionality of the constraints would come into play for long-term rights.

Early optimism that the number of possible binding constraints would be small and easy to identify in advance has faded, but not disappeared. Hence, market participants might be able to choose only a few flowgate rights and provide an adequate,

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13 Richard P. O'Neill, Udi Helman, Benjamin F. Hobbs, William R. Stewart, and Michael H. Rothkopf, "A Joint Energy and Transmission Rights Auction: Proposal and Properties," Federal Energy Regulatory Commission, Working Paper, February 2002.

albeit less than perfect, hedge for transmission schedules. But in this case, the consensus has become that the unhedged portion of congestion costs would be just that—unhedged. There would be no socialization of congestion charges.[14]

An attraction of the flowgate approach is the ability to trade rights in different flowgates without having to limit transactions to the given configuration of PTP options or obligations. However, an inherent cost of this attractive flexibility would be the need to anticipate how the actual system would operate on the day and acquire a very large and changing number of flowgate rights in order to hedge a single point-to-point transaction.

There are other details that arise in defining the rights. However, it is possible to develop a common framework that is general enough to incorporate all these definitions of FTR formulations. This suggests using all four types at the same time.[15] An advantage of this approach is that the market, not the market designers, could choose whatever combination provided the best package of rights for their own transactions. Other things being equal, the do-everything design would be a dominant solution. However, other things are never equal. It would not be very expensive to set up the tariffs and systems to accommodate all four types of FTRs, but it would not be free. And it is not yet clear that it is practical to solve the associated auction or allocation problem for all four rights without imposing substantial limits on the eligible flowgates. Regulators should be cautious about creating expectations about the viability of the do-everything strategy.

Given the simplicity and success with PTP obligations, another market design strategy emerges. Start with what we know works, take no action that precludes an expanded definition up to the do-everything approach, and implement the design expansions as resources, experience and market demand dictate.

Happily, this common sense approach is exactly the policy offered by FERC in the SMD NOPR. Starting with financial congestion hedges, the design strategy is summarized as:

> "We propose that Congestion Revenue Rights be made available first in the form of receipt point-to-delivery point <u>obligation rights</u>, which we propose to mandate now, and later in the form of receipt point-to-delivery point <u>option rights</u> and <u>flowgate rights</u>."[16]

This strategy is commendable. It takes the lead on what is most urgent, but remains agnostic about how far to go. It may be that once market participants become familiar with PTP obligations, options won't be much in demand. Or both PTP obligations and options would be needed and would solve all the problems, with flowgates failing to produce sufficient market interest. Or it might be that everything would have its place, and the flowgate approach could move into a workable implementation without socialization of costs or creation of perverse incentives. Everyone can have a view on how far we might go, but that does not need to be decided

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[14] The same principle should apply to marginal losses, which the flowgate model does not address.

[15] William W. Hogan, "Financial Transmission Right Formulations," Center for Business and Government, Harvard University, March 31, 2002.

[16] FERC SMD NOPR, July 31, 2002, p. 134 (emphasis in original).

at the beginning. About all that seems clear is that the PTP obligations would be part of the package, as this FTR type provides the only workable method to provide a perfect hedge on a simple energy transaction.

These FTRs in their various forms have other important properties not widely understood. Although further details are described elsewhere, three features of PTP obligations deserve mention in that they appear frequently to be misconstrued.

First, configuring PTP obligations is relatively simple. It has been asserted that such an allocation would require:

> "… a process in which a set of all feasible (i.e., consistent with the transmission network) *physical* combinations of bilateral contracts between injection and receipt points is first calculated. The process of defining the feasible set must be conducted by the SO by performing a large set of simulations of the use of the network under various supply and demand conditions and contingencies (e.g. line outages) using load flow models. The process envisioned for defining the feasible set appears to be purely physical in the sense that the SO does not rely on prices or other valuation procedures to define the set of feasible rights."[17]

This would be an onerous task were it required. However, it is not. The misconception may flow from the long history of utilities attempting to assign physical rights that were to apply for long periods of time. In order to guarantee the physical rights, it was necessary to do just as described, and the simulation wars were endless because it was always possible to find some pattern of possible future demand and a contingency where the new rights would be infeasible.[18] By contrast, a great simplification of the PTP obligation as a financial right is that in order to check feasibility of any particular set of awards, the simulation is reduced to a check of a contingency constrained load flow, for which software is readily available. Furthermore, the PTP awards are made regularly through an auction process that uses a characterization of the constraints, not an enumeration of the feasible set. Hence, allocating PTP obligations through an auction does not require anything much more than the same calculations as in a regular economic dispatch, a familiar and well understood problem. This auction software is in regular use for just this purpose in PJM and New York.

Second, revenue adequacy does not depend strictly on maintaining feasibility of the FTRs for every short-term configuration of the grid and load pattern. For example, shift factors can change under different operating conditions. One analysis described this feature of PTP FTRs in accommodating changes in shift factors as "[shift factor] insurance." There was 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."[19] This conjecture may

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[17] Paul Joskow and Jean Tirole, "Merchant Transmission Investment," MIT Center for Energy and Environmental Policy Research, February 10, 2003, p. 40 (emphasis in original).

[18] The first development of PTP obligations arose in an attempt to solve this problem.

[19] Hung-po Chao, Stephen Peck, Shmuel Oren, and Robert Wilson, "Flow-based Transmission Rights and Congestion Management," Electricity Journal, October 2000, p. 40.

flow from an assumption that changes in shift factors would necessarily make the FTRs infeasible, thereby exposing the system operator to some inappropriate financial risk. To be sure, investment in the grid as well as changed operating conditions could have a significant effect on shift factors. But this need not affect revenue adequacy.

The explanation for grid investment appears below. As for grid operations with any given topology of the grid, changing the control settings for phase angle regulators or switching lines in or out need not create any financial exposure despite the resulting change in shift factors. In particular, to ensure revenue adequacy under market equilibrium it is sufficient that the FTRs be feasible for some value of the transmission parameters that are under the control of the system operator, $\hat{u} \in U$. It is not necessary that the FTRs would be feasible at the current optimal setting of the transmission parameters, u^*. Hence, the FTRs might not be feasible at the current settings required in the economic dispatch solution, but as long as they would still be feasible with some possible control settings, there would be revenue adequacy. In addition, 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 control parameter setting that would make the FTRs feasible and that the FTRs would provide a preferred schedule at the current prices. This is possible but unlikely without the unexpected loss of a major facility. Revenue adequacy is not always guaranteed, but the conditions for revenue adequacy are not as brittle as often assumed.

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 or even the most important conditions that result in changed distribution factors. The actual practice of who bears the risk in the case of such revenue inadequacy is different in different implementations, and could be connected to the discussion of incentives for the transmission owner responsible for line maintenance.[20]

A third misconception is related to the effect of contingency constraints.[21] In a representative instance, a discussion of an example illustrating the effects of transmission line outages in a network asserts:

> "Whether it is an efficient investment will depend on the benefit of the link during contingencies like these (and others when it is valuable), the costs of the link during conditions when it is not 'needed' and leads to an inefficient dispatch, and the cost of the investment. It is clear that non-contingent transmission rights cannot be defined properly to capture the varying valuations of a transmission investment under the many contingencies that characterize real electric power networks and provide

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

[21] A contingency refers to the possible loss of a major line or other facility in the system.

> the right incentives to support efficient investments. Only contingent rights provide the proper incentives."[22]

This comment and its accompanying examples appear to imply that a constraint induced by a lost transmission line applies only when the line is actually lost. However, this is not the way security-constrained dispatch operates. A principal reason that networks contain highly meshed system is to preserve reliability in the case of contingent events. The events themselves do not happen very often. However, when the contingencies do occur the power flow redistributes automatically as long as there are loops or parallel paths. The adjustment is so quick that it is generally not possible to redispatch the system. Hence, to keep the lights on, before the contingency occurs the dispatch must be set so that if the contingency would occur the resulting power flows would still be feasible. This is the essence of "n-1" contingency-constrained dispatch. If one out of the "n" facilities is lost, the constraints would still be met. Therefore, the contingency of a line out always applies as a constraint in the dispatch, even though the line may seldom be out.

The definition of FTRs already accounts for this contingency effect, as does the security constrained economic dispatch. This is the main reason that there are hundreds of thousands of constraints in K. The FTR simultaneous feasibility test means precisely that the FTRs would still be feasible in the event of any of the possible contingencies. Of course, in the relative small percentage of time that the contingency actually occurs, the dispatch either reduces to ignoring other contingencies for a brief period until the line can be restored or the FTRs might then be infeasible. Dealing with these occasions is an important issue, but it is second order compared to the problems of the normal contingency constrained dispatch. Most of the time is spent and most of the congestion cost appears during normal operation of the security-constrained dispatch and the many contingency constraints. And for these purposes the FTRs already recognize and accommodate the effects of the monitored contingencies.[23]

The effect and intent of the FTRs is to create a property right that makes electricity more like other markets. It is not possible to craft physical rights that achieve this objective. But with the essential coordinated spot market in place, the FTRs provide the economic instrument that would be equivalent to a perfectly tradable physical right. These FTRs could play a prominent role in the market design for transmission investment.

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[22] Paul Joskow and Jean Tirole, "Merchant Transmission Investment," MIT Center for Energy and Environmental Policy Research, February 10, 2003, p. 49.

[23] Besides actual outages, other factors ranging from temperature to magnetic disturbances from the sun can influence transmission capacity. Again, these are real effects but not as significant as outage contingency constraints.

TRANSMISSION INVESTMENT

The motivation for developing FTRs addressed the need for long-term rights that would be compatible with the short-term electricity market.[24] In addition to providing hedges for the users of the existing network, these FTRs can play a role in the design of transmission markets to include market-driven investment in the transmission system.

Citing the work of the Department of Energy,[25] the FERC has been concerned with a need for more transmission investment and pursuing the design of a market for transmission investments in conjunction with the SMD.

> "The recent DOE National Grid Study documented the problems resulting from recent under-investment in transmission infrastructure and identified a number of causes. Among the causes were the lack of regional planning and coordination of transmission needs and siting issues."[26]

The subject of transmission expansion is important and recognized as a complex problem in electricity restructuring throughout the world.[27] In some special cases, such as for England and Wales, there is a single transmission monopoly over the whole grid, and this special feature allows market designs that are interesting but may not travel well.[28] In the United States, multiple transmission owners, independent transmission providers, and strong interactions among these entities in the same grid limit any application of a simple monopoly approach.

With publication of the SMD NOPR, FERC launched a vigorous discussion of alternative models for transmission investment. To (over)simplify for the moment, it is useful to think of this discussion centering on the optimal mix of two approaches. At one end of the spectrum we have merchant transmission investment, which might be defined in the minimalist sense as market participants making transmission investments in response to market incentives. The merchant transmission investment would be voluntary. The investment cost would not be included in rate base or other mandatory charges. The benefits for the merchant investor would include an award of incremental FTRs created by the investment.[29] At the other end of the spectrum would be regulated investment. This would be much like traditional transmission investment, with cost

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[24] William W. Hogan, "Contract Networks for Electric Power Transmission," Journal of Regulatory Economics, Vol. 4, 1992, pp. 211-242.

[25] U.S. Department of Energy, National Transmission Grid Study, Washington DC, May 2002.

[26] FERC SMD NOPR, July 31, 2002, p. 187.

[27] For an exceptionally rich discussion, see Fiona Woolf, Global Transmission Expansion: Recipes for Success, Penn Well, Tulsa, OK, 2003.

[28] Thomas-Olivier Léautier, "Regulation of an Electric Power Transmission Company," The Energy Journal, Vol. 21, No. 4, pp. 61-92. Ingo Vogelsang, "Price Regulation for Independent Transmission Companies," Journal of Regulatory Economics, Vol. 20, No. 2, 2001, pp. 141-165.

[29] Other rights might accompany transmission expansions. This is particularly the case for designs that include Installed Capacity (ICAP) markets or their equivalent. Here we exclude consideration of these ICAP markets. Either the ICAP markets will persist, and would have to be integrated with the analysis here, or ICAP markets will wither and the present analysis of an energy only market would suffice.

recovery through mandatory charges subject to regulatory approval. Under the FERC plan, this would include an evaluation to identify the beneficiaries for cost assignment. This latter type of "participant funding" is important, but not the main concern of the present discussion. [30]

Hybrid Model

The SMD NOPR began the conversation, and the immediate reaction was all over the map. At one end of the spectrum, there was an assertion that the FERC's "… approach seems to be based on the assumption that we can rely primarily on 'private initiative' to bring forth needed transmission capacity and views 'market driven' decisions as the 'fundamental mechanism' to provide efficient levels of transmission investment. Thus it appears that the Commission has in mind a regime in which the bulk of future transmission investment will be realized by 'merchant transmission projects' that would be supported financially through congestion revenues."[31] At the other end, was the reaction of potential merchant transmission investors that the evolving FERC rules would in fact foreclose any significant merchant transmission investment.[32]

An alternative reading would be that FERC was more agnostic about an investment model that was still a work in progress. Clearly FERC intended to include merchant transmission investment that would be motivated by LMP prices and the opportunity to acquire incremental FTRs. [33] But this is far from a commitment to rely solely or primarily on merchant investments. For example, from the SMD NOPR:

> "The Commission proposes a pricing policy and process for recovering the costs of new transmission investment so as to develop the infrastructure needed to support competitive markets. The policy builds on the price signals provided by the proposed spot market design. However, there are cases where LMP price signals alone will not encourage all beneficial transmission investments. Therefore, we propose to require market participants to participate in a regional process to identify the most efficient and effective means to maintain reliability and eliminate critical transmission constraints." [34]

This could be read as a policy with a "fundamental mechanism" that is "market driven" in responding to price signals made transparent by the core features of the SMD, but neither dependent on merchant investment to provide all transmission investment, nor

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[30] FERC SMD NOPR, July 31, 2002, p. 110.

[31] Paul Joskow, "Comments: Remedying Undue Discrimination through Open Access Transmission Service And Standard Electricity Market Design," Docket No. RM01-12-000, January 10, 2003, p. 6.

[32] TransÉnergieUS, "Market-Based Transmission and Open Access under SMD," Presentation to FERC Staff, Washington, DC, January 22, 2003, p. 2.

[33] FERC SMD NOPR, July 31, 2002, p. 194.

[34] FERC SMD NOPR, July 31, 2002, p. 8.

seeking to have most investments handled as regulated cost of service projects. The distinction is between (i) using the price and FTR information to identify transmission investment opportunities, and (ii) relying solely on market initiatives to make the investment. This interpretation is further reinforced by many other parts of the SMD NOPR. For instance:

> "After Standard Market Design is fully implemented, … [t]here will still remain a significant need for a regional planning process to supplement private "ground up" investment decisions. The regional planning process is intended to supplement these private investment decisions, not supplant them. The regional planning process must provide a review of all proposed projects to assess whether the project would create loop flow issues that must be resolved on a regional basis. In addition, because of the externalities involved, there may be no private investment sponsor for some projects that would benefit the region."[35]

Hence, one reading of the SMD NOPR is that locational prices provide the signals, but the benefits of reduced congestion and FTRs may not be sufficient to support investment in all cases.[36] The goal is to define a workable hybrid model that could accommodate both merchant and regulated transmission investment.

This is an important but difficult strategy. As is generally acknowledged, "[m]ixing regulated and unregulated activities that are (effectively) in competition with one another is always a very challenging problem."[37] If there is to be a hybrid model, a principal task would be to draw a line that would mark the boundary between merchant and regulated investment. Perhaps the most urgent expression of this challenge can be found in a paper by National Grid raising a series of questions that it sees as "weighty and complex issues."[38] The complex issues require careful and explicit attention, and are not likely to be addressed well in a series of piecemeal decisions. A quite real danger is that seemingly innocuous early decisions might have implications that reach further than FERC intended in the narrow context.

Merchant Transmission Challenges

There are many challenges in designing a market to include merchant transmission investment. "Complete reliance on market incentives for transmission investment would be unlikely as a practical matter and is subject to a number of

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35 FERC SMD NOPR, July 31, 2002, p. 191-192.

36 Transmission investment would produce other benefits than FTRs, so support through the exp post value of FTRs is not strictly necessary.

37 Paul Joskow and Jean Tirole, "Merchant Transmission Investment," MIT Center for Energy and Environmental Policy Research, February 10, 2003, p. 13.

38 See the appendix below for details of National Grid's questions.

theoretical challenges."[39] The intent here is not to discuss or dispose of all the difficulties, many of which have been discussed elsewhere.[40] Rather the intention is to highlight the most important problems and consider what these imply about any line to be drawn between merchant and regulated transmission investment.

An initial task is to put the problem in context in terms of the criteria for evaluating market design components. An operating assumption here is that there is a tradeoff between imperfect markets and imperfect regulation. At present, there is no first-best solution available at either extreme to guarantee perfect economic efficiency in transmission investments. This should affect the form of argument. It should not be sufficient to reject a design feature simply because under some conditions this design element alone would not produce the most efficient solution. Uniformly applied, this one-handed comparison would reject all proposals, including the status quo. Rather, the hybrid approach looks to a portfolio of methods that can work concurrently with tolerable friction in addressing most investment opportunities.

Typically expansive lists of the challenges to merchant transmission investment include distinct classes of problems.[41] Problems that have been solved. Problems that apply in any market, or at least any regulated market. Problems that pertain especially to transmission, but are of second order importance. Problems that are significant and possibly insurmountable for merchant investment alone.

As discussed above, examples of (substantially) solved problems include characterizing auctions for FTRs, dealing with changing shift factors, and accommodating contingency conditions that appear in security-constrained dispatch. Another example is the preservation of the feasibility of existing FTRs in the presence of transmission investment that changes the configuration of the grid. In practice and in theory, an elegant and simple set of expansion rules merely defines the incremental FTRs, including counterflow, to guarantee feasibility by construction.[42] Existing rights would be unaffected, perhaps through the device of having expansion FTRs include an FTR obligation in the reverse direction that nets out with an existing FTR.

Examples of problems that apply to any market would include the distortions from efficiency that arise through information asymmetries and agency problems. The SMD with its reliance on independent transmission providers, separate independent transmission companies, and decentralized market participants, all operating in a highly interconnected and interdependent grid, is rife with these conditions. For example, it remains to be seen how in the long-run to maintain incentives for good performance by the system operator. As important as these problems may be, it is not clear how they

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39 William W. Hogan, "Market-Based Transmission Investments and Competitive Electricity Markets," Center for Business and Government, Harvard University, August 1999, pp. 21.

40 Fiona Woolf, Global Transmission Expansion: Recipes for Success, Penn Well, Tulsa, OK, 2003. Sally Hunt, Making Competition Work in Electricity, Wiley, New York, 2002.

41 For example, see Paul Joskow and Jean Tirole, "Merchant Transmission Investment," MIT Center for Energy and Environmental Policy Research, February 10, 2003.

42 William W. Hogan, "Market-Based Transmission Investments and Competitive Electricity Markets," Center for Business and Government, Harvard University, August 1999, pp. 28.

would alter the line between merchant and regulated transmission investment. They are not the focus of discussion here. Rather, a goal in thinking about design of transmission markets is that transmission could become more like these other markets, where we have only imperfect solutions even absent the special complications of electricity transmission. It would be real progress if these were the problems of major concern.

Problems that apply to transmission, but are of second order importance, would include the contingent nature of transmission capacity as a function of temperature, wind speed, thunderstorms, solar magnetic disturbances, and so on. These random conditions can affect transmission capacity, but the impact is typically small and transitory compared to the potential of contingency constraints and changing load patterns. Further, it is not clear how or if these facts could provide much guidance on how to draw a line between merchant and regulated transmission investment.

The most prominent examples of problems that are significant and possibly insurmountable for merchant investment arise from economies of scale and scope. In the presence of such effects, investment in transmission expansion might both expand transmission capacity and have a material effect on market prices. The investment might be economic because the savings in total operating costs could be more than the investment cost, but the resulting value of the FTRs at the new locational prices would not be greater than the investment cost.[43] By contrast, if the transmission investments could be made in small increments relative to the size of the market as a whole, they should have a minimal effect on market prices. In this case of no or small returns-to-scale, acquisition of the financial transmission rights could provide the right market incentive. Prices after the modular expansion would not be materially different than before, even though there would an increase in capacity and throughput. The FTRs would provide the hedge against transmission prices, and for the investor the arbitrage opportunity in the spot market would be sufficient to justify the investment. But with significant returns to scale, prices might change substantially and for everyone, and everyone would wait for somebody else to make the investment. With everyone waiting for the free ride, the investment would never come. This could be important, and it could be the central issue in drawing a line between merchant and regulated transmission investment.

Slippery Slopes

The need to draw a line between merchant and regulated transmission investment is fundamental, and its importance goes well beyond the matter of transmission. Failure could strike at the core of the SMD and electricity restructuring policy. More than is usual, here everything is connected to everything else.

The commonsense problem is that transmission investment does not occur in a vacuum. The choice is not between transmission or nothing. Typically investment in

[43] Paul Joskow and Jean Tirole, "Merchant Transmission Investment," MIT Center for Energy and Environmental Policy Research, February 10, 2003, pp. 21-23.

transmission is one alternative among many. In addition to transmission coupled with distant generation, there is local generation or demand-side investment. Both of the latter investments could reconfigure, reduce or eliminate the supposed need for a transmission investment. In the case of a merchant investment, investors would make the investment choices and take the business risk that alternatives might later alter the value of the investment.

In the case of regulated investment, it is regulators that would make the choice and typically the customer that would take the bulk of the risk flowing from the regulators' choice. It follows, therefore, that the regulator will be under pressure to be explicit about these tradeoffs and investment risks.

This will present the regulator with a slippery slope problem.[44] By definition, regulated investment shifts the risks and provides cost recovery mechanisms not available to the merchant investor. Absent a bright line between merchant and regulated transmission investment, there will be enormous and justifiable pressure on the regulator to consider the alternatives and to put them on the same playing field of reduced risk and mandatory collection through rate base or similar regulated mechanisms. Soon the intended modest domain of planning for and funding regulated transmission expansion would expand to include integrated resource planning and funding for competing generation and demand-side investments.

Absent a demarcation between merchant and regulated investments, there is no logical or principled stopping point down this slippery slope. The end point would be with all investment in transmission, generation and demand defaulting to regulated investment with mandatory charges levied outside the market mechanism in order to provide subsidies or guarantee revenue collection. Therefore, a poor design for transmission investment is a threat to the entire premise of the SMD. The end state could be a recreation of the central regulatory decision problems that motivated electricity restructuring in the first place. But now the central regulator would be FERC and its handmaidens at the ITPs, replacing the old utilities and their state regulators.

This concern for bad market design leading down the slippery slope cannot be easily dismissed. The logic is compelling, and it has already happened in the context of California.[45] Although the California proposals were swept away first by FERC's revulsion at "fundamental flaws" in the original California market design and then the implosion of the California crisis, California was well along in developing just such a central procurement process that would provide ratepayer funded cost recovery for generation and demand investments that were alternatives to transmission investment.[46] Further, the SMD NOPR appears to propose exactly this type of integrated resource

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[44] William W. Hogan, "The Slippery Slope of Socialization," Public Utilities Fortnightly, December 1, 2001, pp. 10-11. Roy Shanker, "Drawing the Line for Transmission Investment," Harvard Electricity Policy Group Presentation, April 7, 2003.

[45] William W. Hogan, "Electricity Restructuring: Reforms of Reforms," Journal of Regulatory Economics, January 2002, Vol. 21, Issue 1, pp. 103-132.

[46] CAISO tariff proposed Amendment 24 Docket No. ER00-866-000 (Revised Long Term Grid Planning), December 21, 1999.

procurement process.[47] The terse discussion in the NOPR does not play out the implications of a single sentence (in paragraph 348), but such a mandate would have far-reaching implications. Once we socialize costs for some erstwhile market decisions, more follow, and market choices are replaced as formalized integrated resource development soon appears again on the agenda of the regulator.[48]

A Portfolio of Merchant and Regulated Projects

The FERC's principal tool for coordinating the portfolio of transmission investments is through the planning protocol required of every RTO. However, as this plan moves from guidance to prescription, more than good engineering analysis would be required. To avoid the problem of the slippery slope, any electricity market design needs an economic rule to distinguish merchant from regulated investment. The conversation took several new turns with the release of the SMD NOPR.

Before the SMD NOPR, virtually all the action on this front was in the design of the New York market and the rules of the New York Independent System Operator (NYISO). The New York system for merchant transmission investment was launched at the beginning in 1999 much in keeping with the eventual outline of the SMD NOPR. The core features of the coordinated spot market and FTRs provide the market setting. Transmission expansion by merchant investors would result in the award of long-term FTRs, but without any guarantee of transmission investment cost recovery.[49] There was a process for deciding on reliability, as opposed to economic, transmission expansion.[50]

The subsequent work at the NYISO has gone much further in dealing with the practical steps for supporting merchant investment and awarding incremental FTRs.[51] This itself is a difficult problem in the context of long-term awards for expansions without a complete set of long-term FTRs for the existing grid. Similar problems arise in trying to use the FTRs to create incentives for better maintenance as envisioned in the SMD NOPR.[52] However, the transmission market design model is well advanced in New York.

Notably, driven in part by history and by its unique status as a single state entity, the NYISO tariff deferred to the state regulator the bulk of the process for deciding on

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47 FERC SMD NOPR, July 31, 2002, p. 193.

48 The reader will notice that the same logic applies to any intervention that socializes costs while competing with market forces.

49 New York Independent System Operator, "FERC Electric Tariff," especially para. 19.4-19.5, March 13, 2003 (available at www.nyiso.com).

50 This distinction between reliability and economics presents another problematic topic separate from the focus of the present discussion.

51 Susan L. Pope, "TCC Awards for Transmission Expansions," LECG, March 20, 2002, (available at www.nyiso.com).

52 William W. Hogan, "Financial Transmission Right Incentives: Applications Beyond Hedging," Presentation at Harvard Electricity Policy Group, May 31, 2002 (www.whogan.com).

traditional regulated transmission investments. The role of the NYISO is primarily as the information producer conducting studies and evaluations of proposed expansions. But, most importantly, the NYISO does not have the authority to mandate regulated investment for reasons of economics alone.

The NYISO tariff supports of merchant transmission investment and allows for regulated transmission investment on the initiative of the transmission owners and with the approval of the New York Public Service Commission. However, the NYISO tariff does not envision a process for requiring transmission owners to make regulated investments for economic purposes. Nor does the NYISO tariff consider mandating regulated investments in demand or generation alternatives to transmission. In its comments on the SMD NOPR, the NYISO expressed reservations about imposing such mandates and recreating "integrated resource planning" in the guise of a transmission expansion protocol.[53]

Development of rules for merchant transmission investment has taken longer in PJM, and the process has gone further in the direction of pushing the ISO to play a central decision role in mandating regulated transmission investment. The basic outlines of these developments flow from a few key directions from FERC and responses by PJM. These have produced substantial debate among PJM stakeholders and would have profound effects on the "complex issues" that could affect all markets under the SMD.

Initially, PJM was inclined towards an approach similar to the New York model. However, FERC directed that "… the planning process should also focus on identifying projects that expand trading opportunities, better integrate the grid, and alleviate congestion that may enhance generator market power. The PJM ISO planning process appears to be driven more by the particular needs of TOs in serving their traditional retail customers than in fostering competitive markets. Consequently, we will require PJM … to specify an RTO planning process that gives full consideration to all market perspectives and identifies expansions that are critically needed to support competition as well as reliability needs."[54]

There may have been some ambiguity about the degree to which FERC's charge "to support competition" implied also mandating regulated investments for economic purposes. This ambiguity was resolved in a subsequent FERC order that clearly indicates "to support competition" means investment for economic purposes.[55] In the concern for showing progress on transmission investment, therefore, these FERC directives have pushed PJM from the role of information provider towards the precipice of the slippery slope of mandating regulated transmission investments for economic purposes, with no

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53 New York Independent System Operator, "Additional Comments: Remedying Undue Discrimination through Open Access Transmission Service And Standard Electricity Market Design," Docket No. RM01-12-000, January 10, 2003, p. 8.

54 Federal Energy Regulatory Commission, "PJM: Order Provisionally Granting RTO Status", Docket No. RT01-2-000, July 10, 2002, p. 29.

55 Federal Energy Regulatory Commission, "Order Granting PJM RTO Status, Granting In Part And Denying In Part Requests For Rehearing, Accepting And Directing Compliance Filing, And Denying Motion For Stay," Docket Nos. RT01-2-001 and RT01-2-002, December 20, 2002, p. 9.

demarcation as yet to prevent slipping into the role of full blown integrated resource planning and procurement.

The unintended consequence is a system of rules that if implemented could virtually eliminate merchant transmission investment incentives and require central procurement of generation and demand alternatives. As envisioned in its filing with FERC in response to these directives, PJM proposed a procedure with an initial screen that would identify "unhedgeable" congestion.[56] Although the term was not formally defined, the expectation and intent was that this category would cover all electricity demand that did not have direct access to inexpensive generation either locally or at a distance coupled with existing FTRs.[57] In effect, therefore, this category would include virtually every transmission expansion that could possibly be of interest to anybody. This would be a screen but it would only screen out that load that already had FTRs or low cost local generation sources.

For this "unhedgeable at a low price" congestion, the second step would be to perform a cost-benefit study to see if a transmission investment would be economic in the sense that the reduced congestion cost would be greater than the cost of the investment. For the unhedgeable congestion that passes the economic benefit test, the proposal envisions a one year period during which competitive merchant transmission or other investments could be made to remove the unhedgeable congestion. If at the end of the year, no market solutions have been forthcoming, PJM would require the transmission upgrade as a regulated investment by one or more of the existing transmission owners.[58]

The PJM proposal includes language expressing its intent that "PJM's planning process thus will allow for competition among all possible alternative solutions for transmission congestion, including generation, merchant transmission and demand response measures."[59] However, it is hard to see how this could be true once implemented. In essence, the proposal would confront all the potential beneficiaries of the transmission investment with the following choice: Invest now and pay all the cost yourself, or wait a year and have much the same benefits with the costs rolled in with transmission access charges for everyone in the region. Unless there is a very good match in identifying the beneficiaries and assigning the costs under the principle of participant funding, it is difficult to see how the choice would be other than to wait.[60] At best, if the investment had no impact on prices, but only expanded transmission capacity, the value of transmission rights would be unaffected at the margin and most customers would be just indifferent. This could produce a narrow or vanishing field for merchant transmission investment.

The PJM proposal does not mention the possibility that the ISO might also have to mandate generation or demand investments as an alternative to transmission

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56 PJM LLC, "Transmittal Letter," Docket No. RT01-2-00-, March 20, 2003, pp. 5-6.

57 Andy Ott, PJM, Personal communication, March 28, 2003.

58 PJM LLC, "Transmittal Letter," Docket No. RT01-2-00-, March 20, 2003, pp. 6-9.

59 PJM LLC, "Transmittal Letter," Docket No. RT01-2-00-, March 20, 2003, p. 6.

60 This observation comes from Roy Shanker.

expansion, and socialize the cost of these investments accordingly. But under the circumstances, it is not hard to see this as the next step down the slippery slope. In addition, the PJM plan and the SMD NOPR avoid the question of what should happen when the market has a different view of the value of transmission expansion. The default proposed is the same central planning default as under the old model of utility regulation. The central planner will be forced to proceed while spending other people's money (the customers'). We would not have the advantage intended for electricity restructuring that investments would be dominated by choices made when participants were spending their own money.

Apparently the unintended consequence of the pressure from FERC would be to drive the investment process away from market solutions. There might be better and more open information in prices and the values of FTRs flowing from the core of the SMD design, but the investment process would be progressively driven to central control and funding through a new broad regulatory process evolving under the rubric of transmission expansion. Like New York, PJM and everyone else should be asking FERC to reconsider before they slide much further down this particularly slippery slope.

A Line Between Merchant and Regulated Investment

The logic driving FERC is understandable. But the resulting direction of policy on merchant transmission could undermine most of what FERC is trying to accomplish in the SMD. Something else is needed.

A critical task it seems would be to modify the rule for drawing the line between merchant and regulated investment. A modest proposal is to leverage the principal problem for merchant transmission investment into a solution. In particular, as discussed above, transmission investments that would produce large and pervasive changes in market prices present particularly severe problems for merchant investment. Pervasive change in prices would apply to many beneficiaries, so it would be hard for the market to prevent free-riding. And large changes in prices would make the ex post value of incremental FTRs much lower at the margin, so low that the FTRs alone would not be sufficient to support the investment. In these cases, only large coalitions would be able to justify a merchant transmission investment, and these coalitions would be difficult to assemble. The alternative then would be to turn to a regulated investment that, in effect, compels participation in the coalition.

A necessary, but not sufficient, condition for this large and pervasive impact on market prices is that the investment is inherently large and lumpy. Not all lumpy investments are big enough to make a big impact on the market, but anything that is lumpy and makes a big impact on the market would be difficult to organize as a merchant investment. This argument then suggests a decision rule that would draw a line between merchant and regulated transmission investment.[61] Regulated transmission investment

[61] John D. Chandley and William W. Hogan, "Initial Comments on the Standard Market Design NOPR," Docket No. RM01-12-000, November 11, 2002, p. 56.

would be limited to those cases where the investment is inherently large relative to the size of the relevant market and inherently lumpy in the sense that the only reasonable implementation would be as a single project like a tunnel under a river. Further, "large" would be defined as large enough to have such an impact on market prices that the ex post value of incremental FTRs and other explicit transmission products could not justify the investment. Everything else would be left to the market.

In evaluating regulated transmission investments, this rule would still be subject to the inevitable pressure to consider generation and demand alternatives that would compete with the regulated investment. However, the same rule would apply to these investments as well. The only generation and demand alternatives that would be included as a mandate and funded through regulated collection mechanisms would be those that were also both inherently large and inherently lumpy. Since relatively few such generation and demand investments would have this characteristic, the line would demarcate the difference between merchant and regulated investments and prevent a slide back into centralized integrated resource procurement. This rule would also recognize that the large network externalities that apply to transmission and frustrate market-driven transmission investments do not generally apply to generation and demand-side investments.

Even though many individually small investments in generation and demand could aggregate to compete with a large lumpy transmission investment, there would be no need to include these in the regulated system. For if it were true that small generation and demand investments would be economic, then there would be no market failure and no need to mandate the investment. The benefits would be easy to capture and prices would provide the needed incentive. The same would apply for small scale transmission investments that would not have a major effect on market prices. In the event that the small investments were not being made, the presumption would be that they were simply not economic, with the market coming to a different conclusion than the cost-benefit analysis of the ISO. In that case, the ISO rules would respect the market's judgment.

This decision rule would be similar in spirit to the PJM proposal to limit attention to "unhedgeable" congestion, but would draw a line that would not require the ISO to make judgments about the price that would define the difference between hedgeable and unhedgeable congestion. It would also be in keeping with the spirit of the NYISO and others to avoid as much as possible any requirement to mandate economic investments in generation and demand. The only exceptions that would require a regulatory mandate would be those cases that have an inherent logic of the same type as large, lumpy transmission expansions.

Applying this rule would require someone to define the criteria and execute the evaluations to determine the effects on market prices and make a judgment about when these are large and the investments lumpy. Although not trivial, this would seem a smaller task than the requirement to do a cost-benefit analysis of the investment.[62] The

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[62] The developing experience in Australia provides important information about the issues and problems that arise in such cost-benefit analyses to evaluate regulated investments. Importantly, Australia's market design does not include critical elements of the FERC standard market design such as nodal pricing and a full system of PTP-FTRs. Hence, the Australian model would not be necessarily transferable to the

information required would be a subset of the cost-benefit study already envisioned. The details would matter, but making this judgment call seems an easier task for the ISO than taking on the much harder problem of selecting virtually all investments in a central planning function.

Drawing this line between merchant and regulated investment would be about as clean and clear as could be expected for any principled approach based on the broader market design. Merchant investment could proceed as PJM intends with "competition among all possible alternative solutions." Regulated investment would be mandated under the special conditions that appear most important in creating market failures that would foreclose a market solution. To be sure, there would be a middle ground where "it would be difficult to distinguish between a project that was simply uneconomic and which the market had rightly rejected and a project that was needed, but the market had failed to profit from the opportunity to build it."[63] By construction, this circumstance would imply that no market failure had been identified, only that the market and the ISO disagreed about the market evaluation. Then the burden of proof would lean against these investments as part of the tradeoff needed to maintain a market at all.

Other Challenges

Drawing a line to demarcate a workable boundary between merchant and regulated transmission investment is the most important challenge. However, there are others that should occupy the continuing debate. How best to provide incentives for good maintenance? How should we handle investments for reliability, voltage support, or other services not explicitly priced in the market? What limitations, if any, should apply to affiliates of regulated transmission companies that want to make merchant investments? What expansion obligations should accompany merchant investments? Who should have access to acquire the rights for "embedded" upgrades of the existing network, and at what cost? What should be done with merchant projects that later apply for regulatory treatment? What performance based incentives should be crafted for operation of the existing grid?

These topics and more could be considered with some deliberation, because they do not strike at the core of the SMD. However, the problem of the slippery slope is more urgent.

U.S. under SMD. The Australian regulatory test does not include an explicit test of market failure and in effect relies on timing and sequencing rules for regulated investments to avoid preempting or distorting unregulated investments. Australian Competition and Consumer Commission, "Discussion Paper: Review of the Regulatory Test," (www.accc.gov.au), February 5, 2003. Bruce Mountain and Geoff Swier, "Entrepreneurial Interconnectors and Transmission Planning in Australia," The Electricity Journal, March 2003, pp. 66-76.

[63] Fiona Woolf, Global Transmission Expansion: Recipes for Success, Penn Well, Tulsa, OK, 2003, p. 251.

CONCLUSION

It should come as no surprise that regulation of a mixed system is harder than being fully in charge of everything. The challenge for regulators is to design rules that set the right incentives and that mesh well within a coherent design. The SMD NOPR achieves a great deal in this regard. However, vigilance is required to guard against seemingly good ideas that would produce bad outcomes. The argument here is that FERC's early guidance on transmission expansion policy presents such a case. The proposed solution outlined in the present paper draws a line between merchant and regulated investment that would support FERC's goals and reinforce rather than undermine the SMD.

APPENDIX

National Grid USA Questions on Merchant and Regulated Transmission

In the context of an application by Conjunction for a proposed merchant transmission investment in New York, National Grid USA raised a series of questions that arise in considering the relative roles of merchant and regulated transmission investment:

"Below is a partial listing of the myriad complex issues raised in those proceedings by National Grid, other parties and the Commission itself and also likely to be raised by Conjunction's proposed merchant transmission line:

- What role, if any, should merchant transmission have in meeting Commission's overarching goal of satisfying the critical needs for investments to expand the integrated transmission system to ensure a robust transmission grid to support competitive wholesale electricity markets? How does the Commission plan to resolve the real-world issues raised by TransGrid based on the Australian experience with merchant transmission regarding (a) the amount of investment merchant transmission can be expected to attract; (b) the impact that it will have on investment in regulated transmission; and (c) other operational and planning concerns about the coexistence of merchant transmission and regulated transmission within the same transmission grid?
- Should the regional planning process encompass both reliability and economic upgrades to the transmission grid, since the two are largely indistinguishable, and if so, how should merchant transmission projects be folded into that process and/or the generator interconnection queue?
- What type of "transmission rights" (physical or financial) does Conjunction intend to sell at negotiated rates? If they are physical rights over the proposed controllable HVDC line, which they appear to be, can they be integrated with minimal disruption into a financially based market design such as the one employed by NYISO and contemplated under SMD?
- What regulatory precautions are needed to ensure that merchant transmission providers such as Conjunction follow through on their commitment to assume all market risks for their projects and do not later attempt (a) to shift such risks onto customers of regulated transmission; (b) to exchange their merchant status for a regulated utility status; (c) to block needed transmission upgrade projects that may tend to undermine the value of the transmission rights sold by the merchant provider; or (d) assert market power?
- What responsibility should Conjunction bear for the cost of upgrades to the existing transmission grid that are necessary to ensure the safe and reliable interconnection of Conjunction's proposed merchant transmission line?

These weighty and complex issues are only tangentially related to Conjunction's request for authority to sell transmission rights at negotiated rates, and National Grid certainly does not expect that the Commission would resolve these issues in the present case. To the contrary, the Commission should resolve these issues in the pending rulemaking proceedings where they first arose and where the national debate has produced an extensive record on which to base such a decision."[64]

Endnote:

[i] Lucius N. Littauer Professor of Public Policy and Administration, John F. Kennedy School of Government, Harvard University and Director of LECG, LLC. This paper draws on work for the Harvard Electricity Policy Group and the Harvard-Japan Project on Energy and the Environment. Joseph Bowring, John Chandley, Art Desell, Scott Harvey, Pete Landrieu, Laura Manz, Andrew Ott, Susan Pope, Jose Rotger, and Roy Shanker provided helpful comments. The author is or has been a consultant on electric market reform and transmission issues for Allegheny Electric Global Market, American Electric Power, American National Power, Avista Energy, Brazil Power Exchange Administrator (ASMAE), British National Grid Company, California Independent Energy Producers Association, Calpine Corporation, Comision Reguladora De Energia (CRE, Mexico), Commonwealth Edison Company, Conectiv, Detroit Edison Company, Duquesne Light Company, Dynegy, Edison Electric Institute, Electricity Corporation of New Zealand, Electric Power Supply Association, El Paso Electric, GPU Inc. (and the Supporting Companies of PJM), GPU PowerNet Pty Ltd., ISO New England, Mirant Corporation, Morgan Stanley Capital Group, National Independent Energy Producers, New England Power Company, New York Independent System Operator, New York Power Pool, New York Utilities Collaborative, Niagara Mohawk Corporation, Pepco, PJM Office of Interconnection, Public Service Electric & Gas Company, Reliant Energy, San Diego Gas & Electric Corporation, Sempra Energy, TransÉnergie, Transpower of New Zealand, Westbrook Power, Williams Energy Group, and Wisconsin Electric Power Company. The views presented here are not necessarily attributable to any of those mentioned, and any remaining errors are solely the responsibility of the author. (Related papers can be found on the web at http://www.ksg.harvard.edu/whogan).

[64] National Grid USA, "Motion To Intervene And Comments Of National Grid USA," Conjunction, L.L.C., Docket No. ER03-452-000, Federal Energy Regulatory Commission, Washington DC, February 18, 2003, pp. 4-5.