UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Maine Public Utilities Commission, et.al.	)	Docket No. EL03-___
Complainants,	)	
	)	
v.	)	
	)	
New England Power Pool and ISO	)	
New England, Inc.,	)	
	)	
Respondents	)	

COMPLAINT OF THE MAINE PUBLIC UTILITIES COMMISSION, THE MAINE PUBLIC ADVOCATE, THE RHODE ISLAND PUBLIC UTILIES COMMISSION, PINPOINT POWER, NRG ENERGY, INC., AND GEN POWER, LLC, REQUEST FOR FAST TRACK PROCESSING AND PRAYER FOR RELIEF

Pursuant to Sections 206 and 306 of the Federal Power Act ("FPA") and Section 206 of the Regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"), the Maine Public Utilities Commission (MPUC), the Maine Public Advocate, the Rhode Island Public Utilities Commission (RIPUC) Pinpoint Power, NRG Energy, Inc. (NRG), and Gen Power, LLC (hereinafter referred to collectively as Coalition Supporting Beneficiary Funding) hereby petition the Commission for an order directing the New England Power Pool (NEPOOL) to file changes to its tariff to implement the beneficiary funding cost allocation methodology described herein and to implement Fast Track Processing Procedures. As discussed below, the current system of socializing the costs of all transmission upgrades of 69 kV or greater is unjust and unreasonable because it requires consumers to pay the costs of projects that do not benefit them. Further, socializing 100 percent of the costs of transmission upgrades is inconsistent with locational marginal pricing (LMP), which does not socialize costs. In addition, socialization of transmission costs will cause additional delays in transmission siting and provide incentives to develop uneconomic transmission projects.

Unlike the current system, the proposal outlined herein provides a method for allocating costs to load that benefits from the project while taking into account concerns that, over time, it is possible that a project may benefit areas beyond the primary beneficiaries identified in the Regional Transmission Expansion Plan (RTEP).

I. SUMMARY OF COMPLAINT

The Commission has long endorsed a policy of cost causation for allocating the costs of transmission upgrades.[1] The Commission also has long been dissatisfied with NEPOOL's proposal to continue socializing the costs of transmission upgrades once LMP is implemented. While ISO New England (ISO-NE) and the New England Power Pool (NEPOOL) recently filed the Transmission Cost Allocation Amendments (TCA Amendments) in response to the Commission's directives to file a new cost allocation methodology, their proposal essentially continues the same socialization methodology that the Commission has determined is incompatible with LMP. Because the Commission has already recognized that the current methodology is inconsistent with locational marginal pricing (in place in New England since March 2003), the Commission should now unequivocally reject the current socialization methodology (as well as the TCA amendments) and in its place adopt the following proposal:

- All PTF projects that have been approved by the RTEP/regional plan will have twenty-five percent of the project costs allocated regionally and seventy-five percent allocated to the local zone(s) that are the primary beneficiaries of the proposal for the life of the facility.

[1] This complaint does not address cost allocation for generation interconnections which is a related but distinct issue.

- Primary beneficiaries are determined with reference to the RTEP. If the RTEP identifies a project as being necessary to address local economic or reliability problems, the zone or zones which contain the local economic or reliability problem identified in the RTEP are the primary beneficiaries. For example, if the purpose of a project is primarily to reduce congestion costs or fix a reliability problem within a zone or zones or within a load pocket within a zone, the zone or zones identified in the RTEP in which congestion costs will be reduced or reliability will be improved as a result of the project are the primary beneficiaries of the project.

- The cost of a project will be rolled in regionally only if the RTEP analysis indicates that there are no identifiable primary beneficiaries.

- This cost allocation methodology would apply to upgrades not under construction as of the implementation of LMP in New England on March 1, 2003 or alternatively to projects not under construction as of the date of the filing of this Complaint.

- The incremental cost of underground lines that could otherwise be installed as overhead lines would be allocated to the zone requiring the burial. However, if population density, technical infeasibility, or sound engineering practice requires underground installation, the cost will be allocated in accordance with the percentages set forth above.

- The cost of merchant transmission will be paid for by bilateral agreement.

- The cost of a new PTF project needed for the benefit of another RTO (ISO) will be paid for by those customers requesting it or by the other RTO (ISO). The cost of a new PTF project that is needed for the benefit of more than one RTO will be paid for in accordance with the benefits received by each RTO or through mutual agreement. "Gold plated" upgrades would also be treated as elective upgrades and supported by the requester.

- Any zone that is transmission export constrained will be exempt from paying a share of any project where the purpose of the project is to eliminate the export constraint.

The proposal outlined above should be adopted because it (1) is consistent with the cost causation policy adopted by the Commission; (2) allows decisions about whether a project is necessary to be made by those who will benefit from and fund such a project, thereby eliminating incentives for approval of uneconomic projects; (3) helps to level the playing field between transmission and other solutions to improve reliability or reduce congestion; (4) will eliminate the need for parties that will not benefit from the project to become involved in the state approval process; and (5) addresses concerns that over time there may be additional beneficiaries of transmission upgrades.

II.

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III. DESCRIPTION OF CURRENT METHODOLOGY

Under the current system, transmission upgrade costs are socialized if they are classified as Pool Transmission Facilities (PTF). The NEPOOL Agreement defines PTF as:

> PTF or pool transmission facilities are the transmission facilities owned by Participants rated 69 kV or above required to allow energy from significant power sources to move freely on the New England transmission network . . .

Restated NEPOOL Agreement §15.1. PTF facilities do not include lines and associated facilities that contribute little or no parallel capability to the PTF, such as radial lines and facilities required to serve local load only. *Id***.** Upgrades classified as PTF receive socialized cost treatment. That is, these costs are rolled into the Regional Tariff and assessed to individual transmission companies based on load percentages. NOATT § 51 and Schedule 12.

IV. BACKGROUND

Current NEPOOL provisions providing for socialization of the costs of transmission upgrades were adopted at a time when the Commission found that "network congestion is not a problem." *New England Power Pool*, 79 FERC ¶ 61,374 at 62,589 (1977). However, it soon became clear that congestion in New England was a problem and the Commission ordered NEPOOL as early as 1998 to develop a congestion management methodology. *New England Power Pool*, 85 FERC ¶ 61,379 at 62,462 (1998). NEPOOL continually delayed making the required filing due to the inability of the various stakeholders to reach agreement on key points. Finally, on March 31, 2000, the ISO submitted a system proposing (1) the implementation of a system of locational marginal pricing (LMP) and (2) the implementation of a day ahead market.

On June 28, 2000, the Commission issued an Order Conditionally Accepting Congestion Management and Multi-Settlement Systems. *ISO New England, Inc.* 91 FERC ¶ 61,311 (2000) (June 28 Order). Among other things, the Commission:

- directed the ISO to explore ways to implement LMP more quickly than its projected implementation time frame which would have had LMP in place between January and June 2002.

- directed ISO to file a revised default allocation mechanism for the costs of transmission expansion that assigns costs of upgrades to those who benefit to the extent they can be identified, whether an upgrade is classified as an "economic" or a "reliability" upgrade.

In a subsequent order, the Commission found that NEPOOL had failed to comply with the Commission's June 28 Order regarding transmission cost allocation. It stated:

> The June 28 Order required ISO-NE to assign expansion costs to those parties who benefit from their expenditure, to the extent those parties can be identified. For costs that cannot be directly assigned, we directed ISO-NE (or NEPOOL) to develop an objective, non-discriminatory default mechanism for allocating transmission and expansion costs similar to the mechanism now in place for PJM.
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> NEPOOL in its compliance filing, *continues to insist that any cost associated with a quick-fix project or a NEMA upgrade will automatically be regarded as a pool-wide expense that cannot be directly assigned. We reject NEPOOL's classifications as unsupported according to the principles in the June 28 Order.* NEPOOL describes quick-fix projects and NEMA upgrades as projects that typically promote reliability by reducing the likelihood of congestion on its system. *NEPOOL does not explain how the NEMA and quick-fix projects provide system-wide benefits that cannot be directly assigned to beneficiaries, nor does it explain how assigning costs for NEMA and quick fix projects to the pool corresponds to an objective, nondiscriminatory default cost allocation mechanism.*

ISO New England, 95 FERC ¶ 61,384 at P. 62,439 (2001) (emphasis added). The Commission directed NEPOOL to make a filing that is compliant with the June 28 Order. *Id.*

Despite this language, NEPOOL persisted in incorporating the socialization of transmission upgrades in its compliance filing. The Commission accepted this socialization *on an interim basis only until the implementation of LMP,* and acknowledged that socialization of the costs of all transmission projects classified as *PTF* is inconsistent with a an LMP pricing methodology:

> NEPOOL has chosen to use the distinction between PTF and non-PTF facilities as its default cost allocation mechanism. This is not identical to the mechanism used in PJM, but it is not entirely dissimilar. *Further, the Commission is mindful that whatever mechanism is selected for New England now, that mechanism will be superseded once a standard market design is applied to the future Northeastern RTO. Thus, for this interim period until that market design is put into place,* the Commission will accept NEPOOL's distinction between PTF and non-PTF facilities as a default cost allocation method for upgrades. The Commission recognizes that, as TransEnergie points out, this mechanism does not send price signals that would encourage the siting of new generation in congested areas. *For*

> *this interim period until the development of a standard market design for the Northeast, however, all congestion costs will be socialized in any case: the financial incentive to site new generation in congested areas will not become meaningful until the imposition of LMP begins to allocate the costs of congestion to the parties who cause it. Thus, LMP and an appropriate default cost allocation method go hand in hand to use market forces to relieve congestion, and since we are currently in an interim period until LMP can be fully developed for New England, it makes sense also to accept NEPOOL's proposed PTF/non-PTF distinction solely for that same interim period.*
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> As to quick fixes and NEMA upgrades, *given that the Commission is now revisiting this particular issue for the third time*, what has become apparent is that (a) NEPOOL and/or ISO NE are unwilling or unable to state any more clearly than they already have why quick-fix and NEMA upgrades benefit the entire pool, and (b) even parties such as TransEnergie, who oppose pool support for quick-fix and NEMA upgrades, do not dispute that these upgrades will benefit the entire pool. *In fact, because these quick fixes and NEMA upgrades have relieved congestion in New England and congestion costs are currently being socialized across the pool, all of the participants have benefited from the quick-fix and NEMA upgrades.*
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> The Commission also notes that in its February 23 Order, it has already ruled that the costs of quick fixes should be recovered "in the same manner as congestion costs are currently recovered," *i.e*. socialized throughout the pool. Since the February 23 Order, circumstances have not changed—LMP has not yet been implemented, and congestion costs continue to be socialized. *Under these circumstances, in order to bring closure to this contentious issue, the Commission will allow socialization of quick-fix and NEMA costs during this interim period.*

ISO New England, Inc., 98 FERC ¶ 61,173 at 61,647 (2002) (emphasis added).

Upon the motion for clarification filed by the MPUC and the Vermont Department of Public Service (VDPS) asking that the Commission clarify that it meant that the interim period would be over upon implementation of a standard market design in New England if that happened before one was implemented as part of a Northeastern RTO, the Commission stated:

> The Commission grants the request filed by MPUC/VDPS, and finds that the interim default cost allocation mechanism for transmission cost upgrades should be reviewed when *LMP in New England is proposed*, but in an appropriate Section 205 or Section 206 proceeding. *We agree that continuation of NEPOOL's socialized cost allocation methodology may be inappropriate once LMP is implemented, as LMP does not socialize costs, but allows parties to see and respond to market signals in planning and locating transmission upgrades.*

> Accordingly, we will require ISO-NE and/or NEPOOL to propose a*revised default cost allocation methodology in ISO-NE's or NEPOOL's SMD filing consistent with an LMP scheme.*

ISO New England, Inc., 100 FERC ¶ 61,029 at 61,078 (2002) (emphasis added). The Commission also rejected the request for rehearing sought by the CTDPUC in which it sought a ruling that the SWCT upgrades should be socialized. The Commission found that the proper time to consider such an issue was in a separate 205 filing by a public utility. *Id.* When neither ISO-NE nor NEPOOL filed the required *revised* cost allocation methodology for transmission upgrades as part of their SMD filing as required by the Commission's July 3, 2002 order, the MPUC protested the filing and asked the Commission to order the ISO-NE or NEPOOL to file a new cost allocation methodology consistent with an LMP scheme. The Commission granted the MPUC request:

> The Commission will grant the Maine Commission's request. Now that NEPOOL is implementing LMP, parties will be able to see more readily which areas would most benefit from transmission upgrades, and what party or parties will most benefit. It is, therefore, appropriate to require those parties to bear the costs of these new upgrades. NEPOOL has in fact stated that it anticipates eliminating the socialization of the costs of transmission upgrades to provide for a mechanism for cost allocation that is consistent with LMP. As we have previously stated in our CMS/MSS orders, we will require ISO-NE to develop a mechanism which, in situations where the parties cannot agree as to who benefits from the upgrade, provides an objective non-discriminatory default cost allocation mechanism that is consistent with cost causation.

100 FERC at 62,285-86.

In its December 20 Order, the Commission clarified that *at that time* it would not foreclose any particular cost allocation methodology because of NEPOOL and ISO's representation that they would try to resolve stakeholder differences in approaches through a stakeholder process. However, the Commission noted that where it had allowed cost socialization in certain circumstances, this was a deviation from its cost allocation principles.

New England Power Pool and ISO New England, Inc. 101 FERC ¶ 61,344 at P. 51 (2002) (December 20 Order).

At each stakeholder workshop convened by the ISO to determine the general cost allocation methodology, the Maine Commission and various other participants expressed concern with the current system of socializing 100 percent of the costs of PTF upgrades and suggested alternatives to the current socialization system. The product put forth by ISO-NE at the end of the stakeholder process, however, continued the current system of socializing the entire cost of transmission upgrades that meet a threshold voltage level.[2]

On June 6, 2003, the Commission deferred ruling on motions for clarification and requests for rehearing of the December 20 Order on issues of transmission cost allocation because the New England Conference of Public Utility Commissioners (NECPUC) had recently represented that it would try to reach agreement on this issue. *New England Power Pool*, 103 FERC at P. 56. The June 6 Order also required ISO-NE or NEPOOL to file within thirty days of the Order a stakeholder process to determine an appropriate set of transmission upgrades for SWCT to receive socialized cost treatment, and an appropriate percentage of the cost of each such project to be socialized. *Id.*, Ordering Paragraph (C). In response to the June 6 Order, the Maine and Rhode Island Commissions proposed to the other New England Commissions and NEPOOL a settlement offer to resolve the issue of the cost treatment of all upgrades not under construction as of March 2003. However, the proposal did not lead to agreement among the state commissions and there was no reason to believe that further efforts would bear fruit. NEPOOL approved the major components of the ISO-NE proposal at its June 25, 2003 meeting. On July 7,

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[2] The TCA Amendments raise the threshold voltage level slightly from 69kV to 115 kV but this is a distinction without a difference because there are few if any projects that would fall between the 69kV and 115kV ratings.

2003, NEPOOL and ISO (hereinafter referred to as “NEPOOL”) jointly filed a report of compliance in response to the Commission’s June 6 Order. On July 31, NEPOOL filed the TCA Amendments. NEPOOL requests an effective date of October 1, 2003 for the TCA amendments. The Coalition has filed a protest to the TCA amendments contemporaneously with this Complaint.

V. THE PROPOSAL

The proposal described below is consistent with locational marginal pricing and also takes into account concerns that beyond the easily identifiable beneficiaries other areas may benefit to some degree over time from a given project.

- All PTF projects that have been approved by the RTEP/regional plan will have twenty-five percent of the project costs allocated regionally and seventy-five percent allocated to the local zone(s) that are the primary beneficiaries of the proposal for the life of the facility.[3]

- Primary beneficiaries are determined with reference to the RTEP. If the RTEP identifies a project as being necessary to address local economic or reliability problems, the zone or zones which contain the local economic or reliability problem identified in the RTEP are the primary beneficiaries. For example, if the purpose of a project is primarily to reduce congestion costs or fix a reliability problem within a zone or zones or within a load pocket within a zone, the zone or zones identified in the RTEP in which congestion costs will be reduced or reliability will be improved as a result of the project are the primary beneficiaries of the project.

- The cost of a project will be rolled in regionally only if the RTEP analysis indicates that there are no identifiable beneficiaries.

- The incremental cost of underground lines that could otherwise be installed as overhead lines would be allocated to the zone requiring the burial. However, if population density, technical infeasibility, or sound engineering practice requires underground installation, the cost will be allocated in accordance with the percentages set forth in paragraph 1, above.

- The cost of merchant transmission will be paid for by bilateral agreement.

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2 Zones are defined as reliability zones in the tariff. If they change, the previous allocation will not change.

- The cost of a new PTF project needed for the benefit of another RTO (ISO) will be paid for by those customers requesting it or by the other RTO (ISO). The cost of a new PTF project that is needed for the benefit of more than one RTO will be paid for in accordance with the benefits received by each RTO or through mutual agreement. "Gold plated" upgrades would also be treated as elective upgrades and supported by the requester.

- Any zone that is transmission export constrained will be exempt from paying a share of any project, the purpose of which is to eliminate the export constraint.

While the Proposal's socialization of 25 percent of the upgrade cost addresses the concern that there may be additional beneficiaries over time of any given project, there are additional ways that the Commission could address this concern. For example, the Commission could allow a graduated roll-in of undepreciated amounts over time. Under this methodology, after a period of time (10 to 15 years) an additional percentage of the undepreciated cost of a project could be socialized. Alternatively, there could be an opportunity for a reopener at set intervals of time, for example, every five to seven years, at which time the ISO could demonstrate that a significant change of beneficiaries had occurred. If there has been a significant change of primary beneficiary, the cost allocation could be modified prospectively to address this change in primary beneficiaries.

We propose that the cost allocation methodology apply to all projects not yet under construction as of the March 1, 2003 date of LMP implementation in New England. We believe that a March 1, 2003 implementation date is fair because the Commission provided more than sufficient notice that it expected NEPOOL to implement a new methodology upon LMP implementation. NEPOOL's refusal to comply with Commission directives for over three years should not now be used by NEPOOL as an excuse to continue to apply its flawed methodology to projects only in the planning stages. NEPOOL Participants who may have had a financial stake in delaying compliance with Commission directives should not now be able to claim that they had no notice of the impending change in cost allocation methodology.

A possible alternative, however, is to have this cost allocation methodology apply to all projects not under construction as of the date of the filing of this Complaint. A project that is not yet under construction cannot be "disrupted" by applying this cost allocation methodology to it prospectively.

VI. ARGUMENT

A. The Current Socialization Methodology is Not Consistent with Locational Marginal Pricing

The Commission has made clear that the current distinction between PTF and non-PTF was a justifiable default cost allocation methodology only *as an interim measure until the implementation of LMP:*

> *Further, the Commission is mindful that whatever mechanism is selected for New England now, that mechanism will be superseded once a standard market design is applied to the future Northeastern RTO. Thus, for this interim period until that market design is put into place,* the Commission will accept NEPOOL's distinction between PTF and non-PTF facilities as a default cost allocation method for upgrades. The Commission recognizes that, as TransEnergie points out, this mechanism does not send price signals that would encourage the siting of new generation in congested areas.
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> . . . .
>
> *Thus, LMP and an appropriate default cost allocation method go hand in hand to use market forces to relieve congestion, and since we are currently in an interim period until LMP can be fully developed for New England, it makes sense also to accept NEPOOL's proposed PTF/non-PTF distinction solely for that same interim period.*

ISO New England, Inc., 98 FERC at 61,647. (emphasis added.). The Commission clearly understands that the current PTF/non-PTF methodology simply is inappropriate under the new market design because, as discussed in detail below, it blunts the price signals that are essential components of an LMP congestion management system. *See also,* Comment of Dr. William Hogan at 1, appended hereto as Attachment 1. In fact, the current methodology was designed and promoted for a NEPOOL that lacked congestion, an assumption that was woefully off mark.

The Commission clearly understands that socializing the cost of transmission upgrades that primarily benefit identifiable local areas is inconsistent with locational marginal pricing. We agree. Socialization, as a cost allocation methodology, is fundamentally inconsistent with an LMP congestion management system. In bid-based competitive markets, LMP conveys price signals that are intended to elicit market responses – either through changed consumption behavior, new generation, or transmission system upgrades (merchant or regulated). Consumers should be spurred to action by the prices, and should have the freedom to choose from a number of competing alternatives that remedy the problem.

Region-wide transmission planning, if combined with socialization of the cost of transmission found to be "needed," will distort risk analyses for both generators and consumers and significantly deter investment in any non-transmission solution *because it will provide incentives for the construction of transmission upgrades that are economically unjustified*. For example, under a cost-causation cost allocation methodology, if a transmission upgrade, additional generation, or load response could relieve congestion in a high-cost congested area, the consumers (or their representatives) in that area might reject a transmission upgrade if its costs were higher than the cost of the congestion or the cost of either additional generation or of load response programs. In that circumstance, the project would likely not proceed and there would be an incentive for investment in generation and load response programs within the load pocket.

If, on the other hand, the costs of an upgrade are spread over a much larger group, even an uneconomic transmission project may be attractive to those who can get the benefit of the project while only having to pay a portion of the cost. Accordingly, investment in demand response or generation that would occur absent subsidies for uneconomic transmission solutions will be deterred. A recent example of this phenomenon is the attached excerpt from a report performed for VELCO. In this report, the consultants examined the cost of the transmission alternative *not in terms of the cost of the entire project but in terms of the amount that would be allocated to VELCO ratepayers if the cost of the project were spread across the pool. See, Alternative to VELCO's Northwest Vermont Reliability Project* (May 2003). Following this logic, Vermont regulators would not consider the true cost of the project in determining whether transmission is the best alternative. They would only consider the small portion that VELCO ratepayers would pay for the project, which is what rational consumers should do in such a situation. This type of comparison does not place transmission on an equal cost footing with generation because the costs of generation are not socialized across the pool, and consequently suppresses price signals that are needed to lead to economic solutions.

The Connecticut Siting Board's analysis is similarly skewed by the prospect of having others pay the majority of the costs of the proposed Phase One upgrade in SWCT. In recently approving an upgrade for SWCT which has a total cost of approximately $200 million,[3] the siting council considered that Connecticut ratepayers would have to pay only 25 percent under a socialization scheme. *See* Findings of Fact. No. 53. Moreover, because Connecticut ratepayers would have to pay only a small share of the total cost of the project, the siting council was willing to approve a plan for using underground transmission lines to address local concerns even though this plan increased the cost of the project by $75 million dollars. These are the types of responses the Commission can

[3] RTEP-03 Executive Summary Draft at p. 2.

expect from a transmission cost allocation methodology that socializes costs regardless of beneficiaries.

The following are additional examples of the likely consequences of improperly socializing transmission upgrade costs:

- Inefficient generators operating in a load pocket will not perform economically preferred plant upgrades [i.e., the conversation of peakers to combined cycle units] because subsidized transmission projects will bring in lower cost generation from outside the load pocket. Older generators will receive an inadequate return on their investment in plant improvements. This is not a hypothetical problem. It is being demonstrated in SWCT. In addition, new generators will be reluctant to develop projects in the region because prices can soon be expected to fall.[4]
- Consumers and private investors will not make significant commitments to alternative technologies with long-term paybacks because of the possibility that the return on their investment will be undercut by a socialized transmission project.
- Load servers will not initiate any innovative pricing programs or invest in real-time metering technologies if they perceive that a socialized solution will reduce prices.

In a market that mixes competition with regulatory intervention, centrally planned transmission projects must be accompanied by mechanisms that allocate the project costs according to the benefits in a way that approximates as closely as possible the economic consequences that would follow from a competitive response. The ISO, ITP, or RTO should develop procedures to facilitate voluntary project financing and allow those who will bear high costs due to congestion or

[4] This problem too has been demonstrated in SWCT. At the RTEP02 Stakeholder review session held in Boston in the summer of 2002, a representative of the Connecticut Municipal Electric Energy Cooperative represented that CMEEC had looked at the costs of developing their own combustion turbine, but that the specter of congestion relief provided by the SWCT projects, funded by socialized cost recovery, made it impossible to secure project financing.

reduced reliability to decide whether the planning results are sufficient to warrant investment in the proposed solution. Such an allocation will provide appropriate price signals for load to make consumption decisions and for state regulators to determine whether the benefits of such projects exceed their costs. By contrast, subsidizing transmission will harm the competitive process and unfairly and arbitrarily enrich some at the expense of others.

B. <u>Primary Beneficiaries Are Easily Identified Through the RTEP and State Siting Process</u>

The RTEP identifies primary beneficiaries with reasonable specificity *and is required to do so by the NEPOOL Tariff.* Further, state siting processes, by definition, identify beneficiaries by determining whether there is a need for the project.

A cursory examination of RTEP-02 makes clear that the RTEP's identification of need is linked to an identification of the project's beneficiaries. The first two projects listed demonstrate this point:

- **NW Vermont Reliability Project** "[T]his Upgrade is required to reliably serve the forecasted loads in the northwest region of Vermont (Burlington area)." RTEP-02 at 178.
- **SWCT 345kV Project** "[T]his reliability Upgrade is required to provide an adequate transmission infrastructure in the southwestern region of Connecticut. . . Although Phase I and Phase II result in little NEPOOL wide LOLE improvement and little reduction in forecasted congestion costs, those reliability and congestion modeling analyses do not reflect the myriad problems internal to SWCT that this project is designed to solve." *Id.*

In all the projects listed in section 11 of the RTEP (with the possible exception of the Norwalk Harbor to Northport line), the beneficiaries are specifically identified. This beneficiary determination can be and is updated along with the need determination in each RTEP until the project is underway. Further, Section 51.4 of the NEPOOL Tariff requires the RTEP to include a description of the reasons for any new Upgrades proposed in the Plan, the anticipated benefits, and if the purpose of the upgrade is to reduce congestion costs, the distribution of the benefits. NOATT § 51.4.

While some may claim that because New England has an integrated transmission system, 100 percent socialization of upgrades is required, this argument proves too much. At its core, this argument simply describes the nature of electricity transmission. The recent blackout underscores the fact that integration of the transmission system extends beyond control areas. If the integrated transmission system is a basis for socialization, then, logically, the costs of upgrades should be socialized across the nation and perhaps the continent.[5] Of course, as discussed above, despite the fact that NEPOOL has an integrated bulk power system, there *are* identifiable beneficiaries for each project and these beneficiaries are described in the process of justifying the need for the project. Further, NEPOOL fails to explain that neither PJM nor the New York control areas socialize costs of transmission upgrades across the control area. Both control areas have license plate rates, which have been approved by the Commission, and are consistent with LMP and the development of competitive power markets.

C. Allocating the Majority of the Costs to the Primary Beneficiaries Is More Rational and Equitable than Simply Assuming that all Upgrades Benefit Everyone Equally Over Time

NEPOOL asserts in its TCA filing that transmission upgrades rated 115 kV or above *by definition* provide system wide benefits, presumably of a magnitude to justify spreading these costs across the region. However, the only support it provides for this assertion is the further assumption that over time beneficiaries of the upgrade are likely to change. That transmission upgrades in one area may, at some point in time, provide some level of benefits to another area

[5] Indeed, the blackout reveals the flaw in the argument that we should socialize costs because of the integrated nature of the grid. This line of reasoning would lead to the conclusion that consumers in SWCT (where the power went out) should pay for upgrades in Northern Ohio.

(perhaps outside of the control area where the upgrade is constructed) is irrelevant to the question the Commission required NEPOOL to address. The Commission told NEPOOL to develop a methodology to allocate the costs of an upgrade that is built to benefit one group of consumers or one or more sub-areas rather than the entire pool. NEPOOL's assertion that over time transmission of a certain size benefits everyone would render the Commission's direction meaningless.

The recent blackout does not change this analysis. While the reason for the cascading effect of the line outage has not yet been determined, there will be those who claim that the far reaching effects of the blackout support the view that upgrades within a control area equally benefit all parts of the control area over time. In fact, at this time, the only conclusion that can be drawn from the blackout is that it is possible for an outage in one control area to have a cascading effect on one or more additional control areas. If, after the ongoing investigations are complete, it is proven that a transmission upgrade would have significantly reduced the risk of blackouts to areas outside of the control area where the outage began, this would prove only that a transmission upgrade may in some circumstances provide a benefit to areas outside of the control area where the upgrade is built. Stretching further, if it is argued that by analogy the cascading effect may in some circumstances take place within a control area and that therefore an upgrade that improves local reliability may, in some limited circumstances, provide a benefit to the entire control area, this argument is addressed by apportioning a percentage of the costs to the entire control area. Thus, at most, the blackout may prove that there is a possibility that the upgrade may in some circumstances provide a benefit to the entire pool[6] but this does not negate

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[6] Interestingly, the blackout spread only to local areas that had been identified by the ISO as local areas that had significant reliability concerns.

the fact that there are certain, identifiable areas that will immediately receive the benefit of the upgrade.

The Coalition Proposal, by allocating a portion of costs of the upgrade to the entire pool, addresses the possibility that an event such as the recent blackout can occur and thus there is a possibility that an upgrade may eventually provide a benefit beyond the area that will immediately and primarily benefit from the upgrade. On the other hand, it maintains the Commission's cost causation principles by allocating most of the upgrade costs to the identifiable and certain beneficiaries of the project.

D. The Coalition Proposal Presents a Workable and Equitable Default Cost Allocation Methodology

NEPOOL has consistently rejected any type of beneficiary funding because of its perception that allocating transmission costs to beneficiaries is overly complicated and will lead to prolonged litigation. There is simply no basis for this concern. There is nothing complicated about allocating 75 percent of the cost of the upgrade to the beneficiaries of the project which are so clearly identified in the RTEPs. Underlying NEPOOL's concern appears to be an assumption that every beneficiary will contest the beneficiary designation made through the RTEP.[7] Even if true -- and it may not be, in light of the moderation of the effect of assigning costs to the beneficiaries accomplished by the 25% socialization proposed by the Coalition -- the fact that parties who ought to pay costs might seek to avoid those costs is no reason to abandon important market principles. If litigation is the fear, it is surely just as likely that, if the NEPOOL socialization approach is adopted, consumers in

[7] Under NEPOOL's hypothetical scenario, designated local beneficiaries or their representatives would presumably be arguing at NEPOOL or ISO that the project does not primarily benefit them while arguing before the local siting board or regulatory commission that the project is needed to address local economic or reliability concerns. While the MPUC does not discount the possibility of such a scenario, it does question whether this absurd hypothetical provides a convincing basis for rejecting a beneficiary pays methodology.

zones who are little benefited by a project but who would be asked to pay for it would litigate against the project as a whole. As one expert has opined:

> Surely, if costs are allocated among those who benefit, those who are charged may challenge the calculation of their benefit. But, if costs are socialized, those that do not benefit also may litigate –not on the basis that they do not benefit, but on the basis that the analysis that determined the need for the project was flawed. At the least, under a cost benefit allocation those that are charged have less incentive to litigate because they have allegedly received some benefit from the project to which they contribute.

José Rotger and Frank Felder: Promoting Efficient Transmission Investment: The Role of the Market in Expanding Transmission Infrastructure, November 2001 at 34.[8]

Further, while we understand that administratively it is simple to just roll all the costs of transmission upgrades into the regional rate as is currently done, there is no reason why our default assignment would be unworkable or overly complicated. In fact, as discussed below, the Commission has recently approved just such a mechanism for PJM.

On July 24, 2003, the Commission approved a PJM proposal for cost allocation of transmission upgrades that is very similar to the approach we have been advocating. The PJM methodology has the following key features:

- The RTO may order transmission upgrades to relieve congestion only if congestion cannot be hedged.
- The RTO's cost benefit analyses will compare potential transmission solutions against wholesale customers' annualized out-of pocket costs of unhedgeable congestion, based on the observed and expected level and frequency of such congestion, with the annualized cost of the transmission upgrade that would be required to mitigate the congestion. The RTO will not order an upgrade if the cost of the upgrade is greater than the cost of the unhedgeable congestion.
- For expansions or upgrades required by the plan, the RTEP will designate the market participants in one or more zones in the PJM region from which the costs of the facilities will be recovered through charges to be developed and filed with FERC by transmission owners.

[8] The web site link for this article is: http://www.ksg.harvard.edu/hepg/Merchant_transmission.htm.

PJM Interconnection, LLC, 104 FERC ¶ 61,124 (2003). This PJM methodology recognizes (as NEPOOL fails to do) that the RTEP process and beneficiary designation involve the same analysis and that requiring the RTEP to designate the entities to which costs will be allocated is simply the logical next step from the RTEP identification of beneficiaries of an upgrade.

While NEPOOL raises the specter of decreased transmission investment resulting from a system that allocates the majority of the upgrade costs to the primary beneficiaries, this concern is entirely unsupported and is inconsistent with the Commission's analysis. The Commission has recognized that a "rolled-in" approach will prevent rather than help projects to get built:

> What we see, however, is that economic expansions that would remove congestion and allow customers to reach more distant power supplies are the most difficult to get sited. This is at least in part because state siting authorities have no interest in siting a line that benefits a particular generator or a distant load in another state because to do would require the load on the constructing public utility's system to pay for the new facilities. The state authorities, at a minimum, need assurance that the costs of that expansion will be paid for by those who benefit from the expansion in order to have sufficient incentive to site the new facilities.

Remedying Undue Discrimination Through Open Access Transmission Service and Standard Market Design, Notice of Proposed Rulemaking 67 FR 55,541 (August 29, 2002) FERC Stats. & Regs. ¶ 32,563 at P.195 (2002).

E. The Coalition Proposal Replaces the Current Unfair System With A More Equitable and Balanced Approach

The current approach is inequitable because it requires areas that are less robust economically to subsidize the costs of projects that primarily benefit wealthier areas of New England. For example, the higher locational prices in Southwest Connecticut, as well as the need for the transmission upgrade, result from greater economic development in that area. Simply put, as we do not socialize the fruits of that development, we fail to see any reason to socialize its costs. To do so is to create a needs-based subsidy for which only the affluent qualify.

NEPOOL has suggested in their TCA filing that because there is the *possibility* that some sub-areas may sometime in the future get a "free ride" from the transmission upgrade, it is unreasonable to ever assess the costs to those areas for whose benefit the project is built. This argument turns traditional notions of rate design upside down. NEPOOL suggests that it is more equitable and rational to *allow the known beneficiaries a free ride* because there is the *possibility* that over time other entities, zones, or sub-zones may benefit in some way from the upgrade.[9] Not only is this exactly contrary to the Commission's cost causation rate design principles, but it cynically proposes that one group of consumers should subsidize the costs of projects that benefit another set of consumers under the guise of *avoiding free riders.*

Further, NEPOOL's rationale imposes a standard that requires 100 percent accuracy in predicting conditions as a prerequisite to requiring identified beneficiaries to pay for the costs of projects but does not impose this standard in recommending that the project be constructed. That conditions change, however, is one of the variables in determining the <u>need</u> for any transmission project. For example, if a project is recommended to address congestion in a local area, the need for the project is based on the same information as the identification of beneficiaries of the project. ISO will project levels of congestion over a set period of time and compare the costs of the upgrade to those experiencing congestion to the costs of not relieving the congestion. While the conditions affecting the congestion projections may change over time, the potential for changing conditions affects not only the beneficiaries but also the need for the project. There is no more justification for saying that beneficiaries should not pay for the cost of a project because in hindsight there may be other potential beneficiaries than there is to say that a project should

[9] When the concern about free riders is put to the test by looking at the reasons for projects such as the Southwest Connecticut Phase I and Phase II upgrades, NEPOOL must make the case that conditions will change dramatically in Connecticut so that reliability would not be at issue in a few years if the projects are not built. This raises the question of whether the projects can be justified.

not be built because in hindsight, projections made about the need for the upgrade may turn out to be incorrect.

Moreover, there is no reason to hold transmission to a different standard from other resources in determining cost allocation simply because transmission is regulated. Just as investors in a generation facility will decide whether, based on the information available, a generation project is a good investment, local beneficiaries can weigh load and cost projections of transmission projects and other alternatives to decide which is the best approach.

Finally, the Coalition Proposal, by recognizing (in its 25% allocation to the region as a whole) the likelihood that everyone will benefit to *some* extent from a major transmission project, avoids the extreme view encompassed in NEPOOL's 100 percent socialization scheme. NEPOOL refuses to consider scenarios other than the two extremes of socializing all or none of the costs of transmission upgrades. In fact, allowing a percentage of the costs of projects to be rolled in while the majority of the costs are allocated to the primary beneficiaries identified in the RTEP is a more reasonable and equitable way to address concerns that at some time in the future there may be free riders.[10] Allowing a percentage of the costs to be rolled in preserves the primary benefits of a cost causation methodology while recognizing the possibility that, over time, the region will share in the benefits of the expenditure to some extent. The current methodology does not even attempt to match cost with cause and thus cannot be found compatible with even rudimentary pricing principles.

[10] Alternatively, there could be a reopener for cost allocation if a significant change in beneficiaries is determined. This does not add uncertainty for investors as suggested by NEPOOL. There is no question that costs will be recovered. The question is who pays these costs. Further, NEPOOL fails to explain its concern with customer certainty. Is it arguing that customers that now receive no benefit from a project would rather subsidize the cost of the project because they will be assured that they will continue to subsidize the cost rather than only being required to pay if they get some benefit from the project? Most consumers in Maine and Rhode Island would embrace this type of "uncertainty."

F. <u>The Coalition Proposal Should Apply to all Projects Not Under Construction as of March 1, 2003 or Alternatively, the Date of this Complaint</u>.

The Commission should apply this proposal to all projects not under construction as of March 1, 2003 because that is the date upon which the Commission told NEPOOL that it should implement a new cost allocation methodology consistent with LMP. Alternatively, the Commission should apply the Coalition Proposal to all projects not under construction as of the date of this Complaint. Parties were on notice as of July 2002 (if not earlier) that a new cost allocation methodology was expected to be in place when New England implemented locational marginal pricing. *See,* 100 FERC at 61,078. There is no reason to believe, and no evidence to suggest, that projects that are not yet under construction would be “disrupted” if the beneficiaries of the project (if it is ever built) are required to pay their fair share of the cost. Indeed, as indicated above, the likelihood of a cost-effective project coming to fruition is likely to be increased, not diminished, by insisting upon cost allocation consistent with LMP and cost-causation principles.

The implementation date is critically important if the Commission adopts, as it should, the Coalition Proposal. Allowing socialization of more than a billion dollars of projects that were not even under construction as of March 1, 2003 would arbitrarily continue a flawed cost allocation methodology.

A look at RTEP-02 makes clear that, of the projects listed in Section 11 of the RTEP, only eight were scheduled to be in service in 2002 at a total cost of approximately $21 million dollars while projects scheduled to be in service in 2003 amounted to approximately an additional $50 million. *See,* RTEP-02, Table 11.1. We would agree that these projects, to the extent they were under construction as of March 1, 2003, would be socialized under the proposed implementation date. The Commission should reject NEPOOL's unsupportable proposal that over a billion dollars in projects should be "grandfathered" simply because they are included in a list in the RTEP.

VII. ADDITIONAL REQUIREMENTS OF RULE 206

In addition to the foregoing, and in accord with Rule 206, MPUC states as follows: (1) no purpose would be served by pursuing alternate dispute resolution procedures because the MPUC and the RIPUC have already tried to reach a compromise but ISO-NE and NEPOOL have shown an unwillingness to move from the extreme position represented by the current rules and the TCA amendments; (2) a form of notice has been included with this filing; and (3) copies of the complaint have been served on the other New England state commissions, the respondent, and on NEPOOL.

VIII. FAST TRACK PROCESSING OF THE COMPLAINT IS WARRANTED

Time is of the essence in resolving this dispute. The filing by ISO-New England and NEPOOL, unless rejected, will take effect as early as October 1, 2003 and no later than five months thereafter if suspended for the maximum statutory period. The Commission has laid down clear, easily-understood rules regarding the allocation of transmission upgrade costs to identifiable beneficiaries in the prior cases cited herein. Absent prompt relief, a transmission cost allocation methodology inconsistent with these cases will go into effect, with potentially significant and immediate adverse consequences for economic efficiency. Fast track processing of the instant complaint is therefore warranted in order to resolve this dispute promptly.

IX. REQUEST FOR RELIEF

The MPUC respectfully requests that the Commission find the current transmission upgrade cost allocation methodology unjust and unreasonable and adopt the cost allocation methodology described herein. This cost allocation methodology should be applicable to all projects not under construction as of March 1, 2003. Alternatively, this cost allocation methodology should be applied to all projects not under construction or completed as of the date of this Complaint.

X. CONCLUSION

What is at stake in this case is the economic efficiency and fundamental fairness of an interstate market for which the Commission bears oversight responsibility. To its credit, the Commission's orders dealing with cost allocation in New England have clearly and repeatedly articulated its commitment to these basic principles. Perhaps because it has been reluctant to insert itself into what it may view as regional political issues, the Commission has shown less willingness to implement these principles than to endorse them. Delay is no longer possible; this filing is the Commission's moment of truth on cost allocation. If it accepts socialization as New England's cost allocation methodology, or if it rejects socialization but yields to the pressure for extensive grandfathering, effectively rendering its rejection meaningless and possibly burdening a later Commission with the task of honoring its rhetoric, its credibility will suffer and market participants and regulators alike will lose confidence in the regulatory consistency and predictability that is the *sine qua non* of healthy markets.[11]

For the reasons stated above, the Coalition Supporting Beneficiary Funding et al respectfully requests that the Commission find NEPOOL's current transmission cost socialization methodology to be unjust and unreasonable and in its place require NEPOOL and ISO to adopt the cost allocation methodology set forth in this Complaint.

[11] In addition, fully grandfathering the SWCT upgrades, and possibly other identified projects as well, will only enhance the unfairness to the beneficiaries of the first project to which beneficiary funding is applied.

August 21, 2003

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C., this 21th day of August, 2003.

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ATTACHMENT 1

Statement of William Hogan

Comment Submitted to the
Federal Energy Regulatory Commission
on
Transmission Cost Allocation Proposal
New England Power Pool and ISO New England Inc.
Docket No. ER03-1141
July 31, 2003

William W. Hogan[i]

August 21, 2003

Introduction

This comment addresses the recently proposed rules for transmission investment and transmission cost allocation (TCA) as offered for the restructured electricity market in New England.[1] The basic theme is that the TCA proposal is both inconsistent with the new market design in New England and not supported by the TCA proposal's own analysis. Rather, the TCA proposal reflects an earlier market design not consistent with open access or market-driven incentives. The principles and policies embodied in the TCA proposal would have far-reaching effects that would compromise the Federal Energy Regulatory Commission's efforts to improve electricity market design. The result would place growing pressure on regulators to manage markets in an effort to counteract the unintended consequences.

Electricity restructuring requires new institutions and new market designs. New transmission access, operation and investment rules are fundamental to the new structure. As the Commission has illustrated in its own analyses of the requirements of good market design, consistency among the major elements is a key requirement for success.[2] Seemingly innocuous decisions affecting one part of the design may have major impacts on other aspects of the system. In the previous world with regulated, vertically integrated monopolies, central control could and did overcome inconsistencies in the incentives in different parts. Hence, an analysis of the interaction of the incentives was less essential. But in the restructured electricity markets, a key purpose is to allow for greater decentralization of production, consumption and, most importantly, investment decisions. Much of good market design isolates the minimum required central coordination (e.g., system operation) and defines how to provide incentives (e.g., prices) to sustain decentralized individual decisions. A challenge for regulators is to design these rules and incentives to support open access and non-discrimination while allowing for efficient market-based choices.

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[1] New England Power Pool and ISO New England Inc, "One Hundredth Agreement Amending New England Power Pool Agreement (Transmission Cost Allocation for New England)," July 31, 2003.

[2] Federal Energy regulatory Commission, "White Paper: Wholesale Power Market Platform," Washington, D.C., April 28, 2003. See also FERC, "Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design," Notice of Proposed Rulemaking, 67 Fed. Reg. 55, 452 (August 29, 2002), FERC Stats. & Regs. 422 (SMD NOPR).

The TCA proposal fails to meet this challenge for three main reasons as discussed below. First, the proposal implicitly embraces a principle of cost allocation that is inconsistent with efficient markets. Second, the proposal does not adequately address the interaction among demand, generation and transmission investments. Third, the proposal does not offer a principled means to demarcate market-based investment and regulatory investment under conditions of market failure. Remedying these defects would point to a different set of investment rules and cost allocations consistent with the Commission's own analysis supporting its Whole Power Market Platform.

Principles of Cost Allocation

The TCA proposal applies many principles that are easily accepted, but there are two implicit principles that need attention by the Commission. In particular, the TCA proposal emphasizes the difficulty of matching the cost allocation with benefits when the ex post benefits and beneficiaries are not know with certainty. In contrast to the ideas underlying the Commission's proposal for participant funding, the TCA proposal builds its main case for a socialized or rolled-in cost allocation rule by arguing that in most instances the beneficiaries are likely to change in unexpected ways and, therefore, it is appropriate to spread the costs equally across everyone in the expectation that in the end everything will even out.[3]

Note that this argument is not the same as saying that a particular investment was expected to have multiple beneficiaries and, therefore, the allocation of costs should be shared across the beneficiaries according to the expected (in the sense of average) benefits. Under participant funding, it would be quite reasonable for the cost-benefit analysis that would accompany a decision to go forward with a transmission investment to identify different beneficiaries with varying expected benefits. The associated cost allocation, made in principle at the time of the investment decision, would assign costs according to some rule that matched costs to expected benefits. By contrast, the TCA proposal argues to socialize the costs beyond the expected beneficiaries.

To illustrate, suppose we applied the TCA logic to time-shared condominiums on Cape Cod. As everyone knows, Cape Cod in the summer is highly congested, and in the winter the Cape is essentially deserted. In large part this depends on the weather, and even the off-season during winter weeks can be wonderful. Following the TCA logic, since the weather can change, time slots in the summer and winter should be charged the same. This would be hard to enforce in the condominium market, but if we had a condominium regulator it might make the regulator's life easier if she could compel investment in condominiums under this cost allocation rule. It certainly would appeal to the parties snagging time during the summer weeks.

It is true that the weather could change from season to season and year to year, but it is not hard to argue that the condominium investment cost allocation could be different for a summer or winter week. Similarly, under participant funding for

[3] New England Power Pool and ISO New England Inc, "One Hundredth Agreement Amending New England Power Pool Agreement (Transmission Cost Allocation for New England)," Transmittal Letter, July 31, 2003, see p.14 and p. 20 .

transmission investments the beneficiaries might be different at different times, and it would be possible to assign the costs according to the expected benefits. In other words, uncertainty about benefits does not mean ignorance about benefits.

Another implication of the TCA analysis goes even further. The TCA proposal's argument is that anything other than equal sharing of costs would require that after conditions had unexpectedly changed "costs would either have to be reallocated, causing uncertainty and instability for investors and customers, or the costs would continue for a group that may no longer receive any special benefit while others get a 'free ride.' Either of these consequences is undesirable."[4] In other words, if investors in the prospective condominium development pay more for a summer than a winter week, a rainy summer and a balmy winter would require either a reallocation of the costs or there would be winners and losers, and 'either of these consequences is undesirable.' The bad effect is simply asserted, but the assertion needs examination.

In the real condominium market, of course, prices before the fact would be different for investors in summer and winter weeks. Depending on later conditions, investors would be more or less content with their choices, but would not expect to revisit the investment decision. Similarly, investments in electricity generation or demand-side efficiency improvements would reflect the expected benefits. Changing conditions could make for high or low returns on the electricity investments, but there would be no expectation that generators or consumers could request a later cost reallocation to protect their investment returns. And this consequence is neither undesirable nor unanticipated.[5] To the contrary, a principal motivation for electricity restructuring is to move investment decisions away from central control and towards market choices where the risks balance with the rewards. The existence of winners and losers is part of the fabric of the discipline of the market, and removing that discipline would seem on its face to be counterproductive in the case of either condominiums or generating plants.

There is an important difference between transmission investments under the TCA proposal and generation or efficiency investments. Payment for the included regulated transmission investments would be mandatory under the coercive power of regulation. By contrast, generation and efficiency investments are voluntary under the market design. However, this difference in kind does not dictate that costs should be shared equally for transmission. The primary significance of the difference is that equal cost sharing could not be sustained in a voluntary market. Hence, equal cost sharing requires regulation. But a goal of regulation should be a transmission cost allocation rule consistent with the rest of the market design. An efficient cost allocation would even have as a goal an approximation of a market outcome were the investment made without the market failure that leads to the need for regulation. Hence, regulation need not require equal cost sharing.

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[4] New England Power Pool and ISO New England Inc, "One Hundredth Agreement Amending New England Power Pool Agreement (Transmission Cost Allocation for New England)," Transmittal Letter, July 31, 2003, see p.14.

[5] The TCA proposal examples illustrate that uncertainty about benefits and beneficiaries is not restricted to transmission, but applies as well to generation and efficiency investments. For instance, see the analysis of the effects of changing oil and gas prices in March 2003, p. 14.

The Commission's own argument for the principle of participant funding rejected the notion that regulation requires socialization of costs beyond the expected beneficiaries. The TCA proposal carries with it an argument strongly at odds with the Commission's stated view of participant funding. It is one thing to claim that there is uncertainty in benefits and difficulty in making cost allocations. It is quite another to go the extra steps to suggest that regulated investment cannot give rise to winners and losers, and that for all regulated investments the expected benefits and beneficiaries are so amorphous as to make any reasonable cost allocation impossible.

Transmission investments do have some unique features, and probably are more prone to the effects of market failures. However, analysis of these conditions leads to a different result than socialization of all regulated transmission investment costs.

Interaction Among Investments

Transmission investments cannot be analyzed in isolation from generation and efficiency investment rules and incentives. A goal of electricity restructuring is to leave most if not all investments in generation and efficiency to market forces. Under an efficient market design, of the type recently put in place in New England, locational marginal prices (LMP) and the associated settlements system provide market signals about when and where to generate and consume electricity. Further, expectations about the future course of these prices should provide the major signal and incentives to guide market participants in deciding on when and where to make generation and efficiency investments.

The new market design in New England is being refined to improve price determination to provide a more faithful representation of opportunity costs and scarcity in energy and operating reserves. There is market power monitoring and mitigation for the energy and reserves market. And there is a generation capacity requirement that is not quite consistent with this market design. But for the present discussion, these are second order issues. To a first approximation, the market design presupposes that the when and where of generation and efficiency investments will be driven by market signals, and investors will both reap the rewards and bear the risks of these investments.

There is a strong interaction among transmission, generation and efficiency investments. But the relationship is not so simple as straight competition for investment dollars. There is a mixture of substitutes and complements. When considering delivery to a load center, distant generation and efficiency investments require transmission to move from the source of available energy to the consumption destination. Therefore, such generation and efficiency investments are complements of transmission. The distant generation or efficiency combined with transmission then substitute for generation or efficiency investments at the load center. The mix of complements and substitutes can be complicated by many network interactions under the general topic of loop flow or the requirements of voltage support. But it is too simple to say that transmission is either only a substitute or a complement. Transmission complements some electricity investments and substitutes for others.

It follows that transmission investment rules and cost allocations can have a significant effect on the incentives for investment in generation and efficiency. If we socialize the cost of transmission investments, the result would tip incentives towards more of those generation and efficiency investments that were transmission complements. At the same time, socializing the cost of transmission investments would blunt the incentives for load center efficiency or distributed generation investments that would be transmission substitutes. The problem then is not merely selecting the efficient level of transmission investment. Even with the right level and investments, socialization of costs could alter, perhaps substantially, the mix and location of generation and efficiency investments that we seek to leave to the market. As evidence of the importance of this effect, recall that socialization of transmission congestion costs and the resulting impact on the locational distribution of generation investment (too much generation investment at locations distant from loads) was at the heart of the earlier problems in New England that precipitated the reforms in market design recently implemented.[6]

This fact of strong interaction among the investments, but not in a simple way, supports the argument above that a goal of regulated transmission cost allocation should be to approximate a market-like outcome. To the extent this could be achieved, the more justified would be the related goal of leaving generation and efficiency investments to decentralized decisions made in response to market incentives.

Market Failure, Investment and Cost Allocation

Market failure complicates the interaction among investments and is complicated by cost allocation rules. A summary of the issues sets the stage for considering the requirements for regulated investment and cost recovery.[7] The attraction of markets with voluntary investment in generation and efficiency may apply as well to transmission investment. The LMPs provide pricing for transmission congestion that creates market incentives. Accompanying these incentives are property rights that reflect the opportunity cost of congestion when using the grid. The locational marginal pricing and financial transmission rights (FTR) recently put in place in New England provide just such a market incentive package. Merchant transmission investments could be made based on these market incentives and rights alone.

However, as the both the Commission and the TCA proposal recognize, transmission has characteristics of that may cause markets to fail.[8] The principal argument is that large scale transmission investments would necessarily exhibit economies of scale and scope, making it difficult to capture the benefits. The economies of scale would mean that investment would produce such large changes in market prices

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6 New England Power Pool, 85 FERC Para 61,141 (1998). Federal Energy Regulatory Commission, New England Power Pool Ruling, Docket No. ER98-3853-000, October 29, 1998. 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. Federal Energy Regulatory Commission, “Order Conditionally Approving Congestion Management and Multi-Settlement Systems,” Docket No. EL00-62-000, June 28, 2000.

7 For a more extended discussion, see William W. Hogan, “Transmission Market Design,” Center for Business and Government, Harvard University, Texas A&M Conference Paper, April 4, 2003.

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

that the resulting FTR property rights would not be valuable enough to justify the investment. And the economies of scope mean that the benefits not captured by the investment would be so broadly dispersed that there would be too many free riders and the investment could not go forward.

The argument for centrally directed transmission investment and its associated regulated cost allocation is to overcome these market failures. Immediately this raises questions about the proper mix of regulated and market investments, and how to draw the line.

In evaluating the possible answers, it is important to remember the context of electricity restructuring. A major premise of restructuring away from central command and control is that markets would make superior investment decisions. Other things being equal, market participants spending there own money would be better overall in balancing risks and rewards than would central planners spending other people's money. Were this not the case, there would be less need to restructure at all. We could simply let the central planners gather the facts and dictate the investment.

This market versus regulatory divide is narrow when the planner and the market agree on the worthy investments. The interesting case is when the planner and the market disagree. In essence electricity restructuring embodies a default rule. The planner might be right, but experience suggests that the market may have a better ability to innovate with alternatives or a better balance of risk and reward. When the planner and the market disagree, defer to the market.

When other things are not equal, because of market failure, the issue becomes more complicated. Here the different investment choices may flow from the market failure, and not just from better information about alternatives or a preferred balancing of risks and rewards. This suggests that part of the task of drawing the line must be in identifying first if there is a substantial market failure.

The TCA proposal draws the line with an implicit definition of market failure. In effect, the TCA proposal defines market failure as a failure of the market to make the investments preferred by the central planner! Any investment that the central planner deems worthy would be mandated and virtually all would be socialized if the market investors did not step forward. "Only when the market fails to respond to identified needs do regulated transmission solutions go forward. Only those regulated transmission solutions that provide a regional benefit will receive regional cost support."[9]

This turns the presumption of electricity restructuring on its head. And it points down the slippery slope towards more and more decisions migrating from markets to planners. Other than an assertion that we need not look behind that curtain,[10] there is no

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[9] New England Power Pool and ISO New England Inc, "One Hundredth Agreement Amending New England Power Pool Agreement (Transmission Cost Allocation for New England)," Transmittal Letter, July 31, 2003, p. 17. The cost socialization exception would be the narrow cases of "Local Benefit" illustrated by the example of a radial connection.

[10] New England Power Pool and ISO New England Inc, "One Hundredth Agreement Amending New England Power Pool Agreement (Transmission Cost Allocation for New England)," Transmittal Letter, July 31, 2003, p. 22.

analysis or principle in the TCA proposal that would preclude the same policy for generation or efficiency investments. Quite the opposite, given the TCA presumption and proposal it would be logical to extend the rule to all forms of investment in generation and efficiency. If the TCA proposal is correct in its analysis, a fundamental premise of electricity restructuring itself is a mistake.

Short of this conclusion, there must be some principle that could demarcate the boundary between merchant and regulated investments. The Commission faces two tasks here. First, recognize that the demarcation for transmission will inevitably spread to other investments. Second, draw the line and allocate the costs consistent with the underlying problem and market design.

There is an alternative available that meets these tests and is only a modest extension of the policy the Commission proposed for participant funding. In essence, the transmission market design should explicitly apply the market failure argument to provide a consistent market failure test.

Transmission Market Design

Transmission market design should be consistent with the overall electricity market design.[11] Under the market design of the Commission's Whole Power Market Platform, transmission investments that expand capacity would create incremental FTRs that could be awarded along with the investment. The investment should reduce total congestion costs but may not have a major impact on prices. The outcome depends on many factors such as the net response of supply and demand throughout the grid. Added to contracts for long term power, the net effect could be that the benefits could be captured my merchant investments.

Even in the case where a large cumulative transmission investment might have a material effect on prices, merchant transmission investments might suffice if the investments could be made cost effectively in small increments. The investment criterion should be to balance marginal benefits with marginal costs, which could be done with merchant investments even if total benefits might be much greater than total costs.

There may be some transmission projects that might not be appropriate for merchant investment. The conditions required would include some form of market failure. Broadly there are two categories of market failures discussed. First, there might be benefits that would not be priced in the market. For example, some local voltage support contributions might be difficult to include in LMPs or the LMPs might be constrained by price caps. The benefits might be sufficient to justify the transmission investment even if market value of the incremental FTRs would not. These are the kinds of investments often described as 'reliability' investments needed to meet certain grid standards even though they do relatively little to reduce normal congestion or improve economics for services priced in the market. The typical alternative to the investment

[11] William W. Hogan, "Transmission Market Design," Center for Business and Government, Harvard University, Texas A&M Conference Paper, April 4, 2003 (attached).

would be local load shedding, so the beneficiaries could be identified even though the benefits might not be priced in the market.[12]

The more common source of market failure would be for large scale projects that are inherently lumpy, so that the investment comes only in the large size. The big, lumpy project would have normal economic benefits and a material impact on market prices. The ex post value of FTRs might not be sufficient to justify the transmission investment even the total benefits might be greater than the total cost.

This then suggests principles that would distinguish merchant and regulated transmission investments. For reliability investments, there must be plausible conditions where there would be no possible redispatch at any cost that would preclude local load shedding. The incremental FTRs created, if any, would not be sufficient to support the return on investment. These reliability investments would be rather limited and focused on grid standards that cannot be modeled explicitly in a normal economic dispatch or where prices could not reflect the value of the reliability. Similarly, for investments driven by economics that could be priced in the market, the transmission investments should be large and lumpy enough that the incremental FTRs could not capture enough of the benefits to justify the investment costs.

The same logic would apply to generation and efficiency investments. However, there would not be the same problem of slipping back to central-planning-for-everything simply because few if any generation investments, and virtually no imaginable efficiency investments, would ever have such large economies of scale that they would suffer from these problems of market failure.

The test should be workable because part of the requirement for regulated transmission investments would be precisely to do a cost-benefit analysis. As a by product, the analysis would almost necessarily estimate the expected LMPs and the resulting value of any incremental FTRs. The TCA proposal argues that this would be contentious and subject to challenge. But it is inherent that the uncertainty around the estimates of benefits and the estimates of the value of the FTRs would go hand in hand. It should be no more or less difficult to determine whether the large-scale-and-lumpy test had been met than to determine that the expected cost-benefit test had been met.

Of course, there could be circumstances with no identifiable market failure and cost benefit analysis seems to justify the investment, but no merchant investment is forthcoming. In this case, the principle would be to defer to the market and not simply assume the central plan must always be correct. Absent identifiable conditions leading to market failure, not just that the market and the planner disagree, the treatment of transmission investments would be the same as the treatment of generation and efficiency investments.

This line between merchant and regulated transmission investments would define a workable demarcation between those transmission investments that would be left to the market and those that would be mandated by regulators for construction and cost

[12] The definition depends on the market design. For example, absent price caps and with complete demand bidding there might not be any need for so-called reliability investments.

allocation. This would then lead to the need for principles of cost allocation for the regulated investment. The TCA proposal applies a binary simplification of the spectrum of possibilities. At one end of the spectrum is the simplest case of the radial line where it should be easy to isolate the beneficiaries, and this is the local benefit exception. Everything else would be socialized (rolled in) across all customers in the grid.

The reality of transmission investments is more spread across the spectrum of possible cost allocations. For example, while customers in generation surplus regions may see some benefits on some occasions from the grid enhancement, it is unlikely that the expected benefits looking forward would be anywhere near those of the customers in the generation deficit region to which the increased transmission capacity would carry the power.

The cost-benefit analysis required for regulated investments inherently includes an estimate of the impact of transmission on different parts of the system and, therefore, an estimate of the distribution of expected benefits going forward. The TCA proposal acknowledges this reality but then argues that finding the right place in the spectrum to place the cost allocation would be even more contentions. The essence of the argument is that the total benefits may be relatively insensitive to assumptions, but the distribution of benefits would be both more uncertain and more contentious. "There will certainly be cost and planning studies that identify undeniably that net benefits will result from proposed upgrades. Details concerning alternative data input and assumptions are not likely to change those conclusions about net regional benefits. The same cannot be said, however, if these data and assumptions are used to assign costs intra-regionally."[13] Hence, since we can't be sure about the winter or summer time slots for the Cape Cod condominium investment, we should assume that they are the same. The uncertainty about being exactly right in the cost allocation should be exchanged for a certainty that we are exactly wrong.

This is a great leap in logic that is unlikely to be universally true and, in any event, is subject to empirical test. If it were true that for a particular investment in the grid a small and reasonable change in parameters could leave the total benefits unaffected, but dramatically change the distribution of benefits, this should be demonstrable. Further, the demonstration alone would be a principal source of information for calculating the expected (in the sense of average) distribution of benefits for the cost allocation going forward.

Simply saying that the system is integrated does not prove that beneficiaries cannot be identified, however imperfectly. And the impact on the rest of the market could be important. Every cost allocation creates incentives for other investments. Picking the wrong cost allocation may look simpler in the particular case, but the downstream effects on other transmission, generation and efficiency investments could easily be much more problematic.

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[13] New England Power Pool and ISO New England Inc, "One Hundredth Agreement Amending New England Power Pool Agreement (Transmission Cost Allocation for New England)," Transmittal Letter, July 31, 2003, p. 15.

Furthermore, from the analysis supporting its own participant funding proposals, the Commission should recognize the flaws in the TCA proposal would be even more apparent if the logic were more broadly applied. Recall the agony of the debate about postage stamp transmission access charges, which are like the rolled-in cost allocation. Postage stamp proposals then serve as a principal obstacle for creating larger regional transmission organizations. Only when the Commission adopted license plate rates, that kept the costs more with the beneficiaries, could larger regions go forward. By the TCA logic, as the regional market expands, so too should the transmission investment cost spreading. With no principled choice in the spectrum of possibilities, the only logical endpoint would be local benefit allocation for radial lines and one giant rolled-in allocation for the national grid. Whatever the appeal of that "simple" policy, it is clear that regulators would soon be fully engaged in deciding on the location and mix of generation and efficiency investments with the associated socialization of the costs. The market would be left to handling short-term operations.

Conclusion

New England had been heading towards a cost allocation more consistent with the Commission's logic for efficient markets. The Commission's participant funding principle would be consistent with the efficient market design in New England. The revised TCA proposal here is a product of frustration in negotiating a meaningful participant funding rule. Were the impacts only to shift the allocation of sunk costs, the debate among winners and losers would be of less concern to the Commission. But this case is something much different. The TCA proposal is really a rule for making and allocating future investments. The incentive effects then loom large. Taken literally, the TCA logic provides a formula for overturning a fundamental premise of electricity restructuring. Given the TCA proposal, there would be a strong argument for reintroducing regulatory control over all major investment decisions in the electricity system with a corresponding socialization of the costs. By contrast, the Commission's participant funding proposal for allocating the costs to the beneficiaries could adopt a line between merchant and regulated investments and then allocate regulated costs in a manner workably compatible for the restructured electricity market.

Attachment

William W. Hogan, "Transmission Market Design," Center for Business and Government, Harvard University, Texas A&M Conference Paper, April 4, 2003.

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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, Edison Mission Energy, 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, Maine PUC, 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, Pinpoint Power, 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 www.whogan.com).

TRANSMISSION MARKET DESIGN

April 4, 2003

Electricity Deregulation: Where to From Here?
Conference at Bush Presidential Conference Center
Texas A&M University

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CONTENTS

TRANSMISSION MARKET DESIGN

William W. Hogan[ii]

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." [14]

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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[14] 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)[15] target the essential requirements for a competitive electricity market.[16] 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

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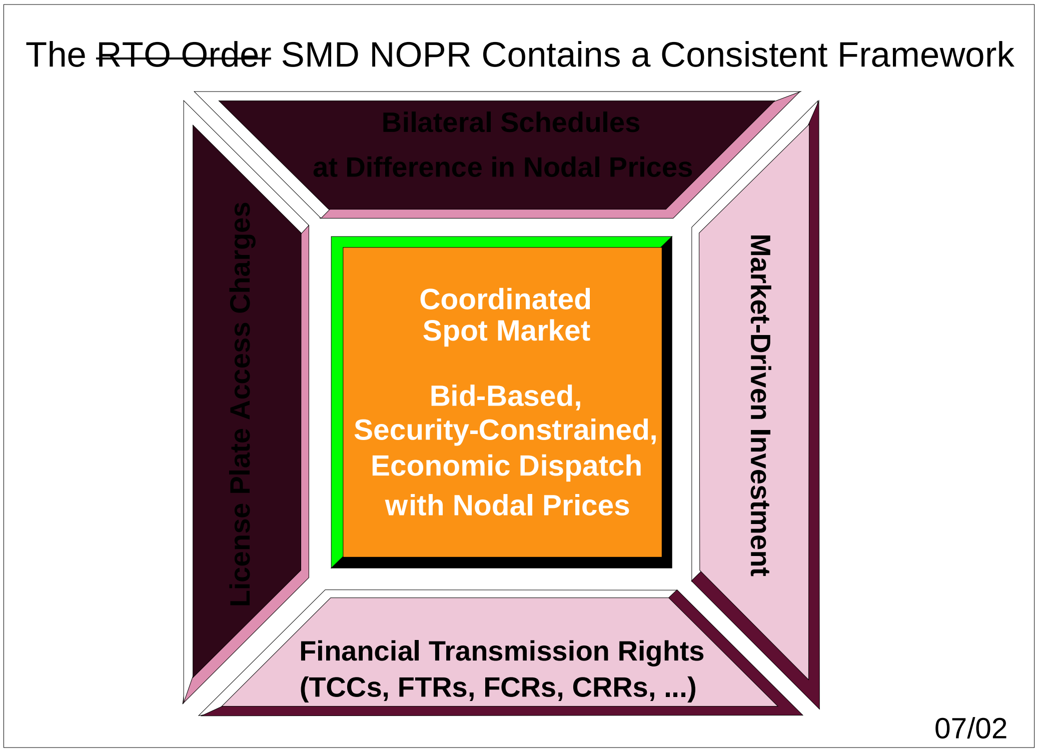
15 Federal Energy Regulatory Commission, Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design, Notice of Proposed Rulemaking, Washington DC, July 31, 2002.

16 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.

investments. In addition, the creation of financial transmission rights provides further opportunities and incentives for market participants to undertake transmission expansion.



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)[17], as well as notable failures.[18] 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

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[17] 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.

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

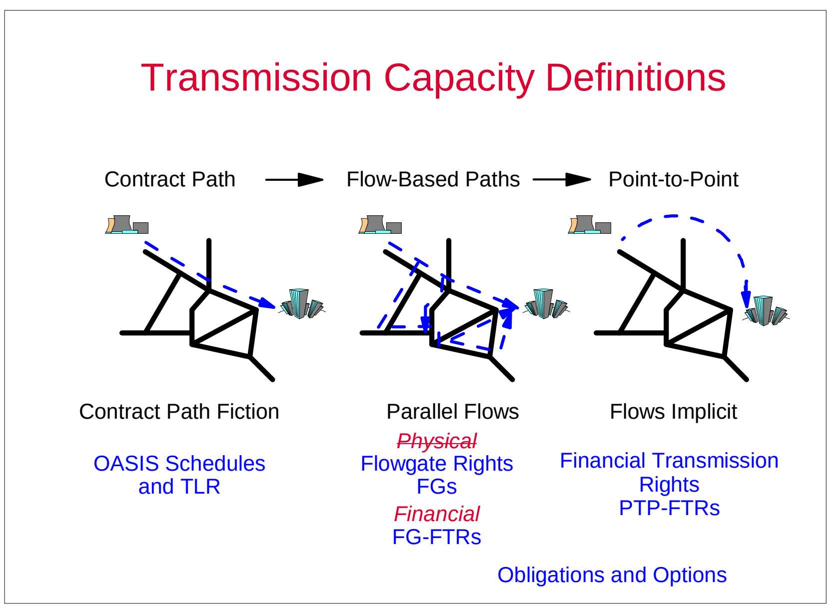
SMD framework, and the elements often absent in the failed experiments. An independent entity operating with the protocols of a coordinated real-time spot market with consistent locational pricing to reflect the actual limitations of energy availability and transmission constraints is first among these 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).[19]

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



[19] 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.

"physical," meaning that somehow the actual flow of power 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.[20]

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. [21]

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.[22] 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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[20] 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.

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

[22] 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:

$$p^t = \nabla B\left(d^*\right) = \nabla C\left(g^*\right) = \lambda \iota^t + \lambda \nabla L_y\left(y^*, u^*\right) + \eta^t \nabla K_y\left(y^*, u^*\right). \qquad (2)$$

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.	$\sum_k \eta_k f_{fk}^o$, $\eta_k = shadow\ price$, $f_{fk}^o \geq 0$, $the\ flowgate\ amount$. 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.[23]

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.[24]

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.[25] 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,

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

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

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

25 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.[26] 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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[26] 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.[27]

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.[28] 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>." [29]

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.

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

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

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

Everyone can have a view on how far we might go, but that does not need to be decided 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."[30]

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.[31] 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

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

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

have a substantial impact on the ISO's uplift charge in later years."[32] This conjecture may 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.[33]

A third misconception is related to the effect of contingency constraints.[34] 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

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

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

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

> varying valuations of a transmission investment under the many contingencies that characterize real electric power networks and provide the right incentives to support efficient investments. Only contingent rights provide the proper incentives."[35]

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.[36]

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

[36] 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.[37] 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,[38] 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."[39]

The subject of transmission expansion is important and recognized as a complex problem in electricity restructuring throughout the world.[40] 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.[41] 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.[42] At the other end of the spectrum would be regulated investment. This would be much like traditional transmission investment, with cost recovery through mandatory charges subject to regulatory approval. Under the FERC

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

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

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

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

[41] 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.

[42] 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.

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. [43]

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."[44] 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.[45]

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. [46] 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." [47]

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 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

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43 FERC SMD NOPR, July 31, 2002, p. 110.

44 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.

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

46 FERC SMD NOPR, July 31, 2002, p. 194.

47 FERC SMD NOPR, July 31, 2002, p. 8.

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." [48]

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.[49] 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."[50] 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."[51] 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 theoretical challenges."[52] The intent here is not to discuss or dispose of all the

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

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

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

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

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

difficulties, many of which have been discussed elsewhere.[53] 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.[54] 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.[55] 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 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

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

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

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

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.[56] 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 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

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

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.[57] 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.[58] 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.[59] Further, the SMD NOPR appears to propose exactly this type of integrated resource procurement process.[60] 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

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[57] 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 8, 2003.

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

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

[60] FERC SMD NOPR, July 31, 2002, p. 193.

follow, and market choices are replaced as formalized integrated resource development soon appears again on the agenda of the regulator.[61]

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.[62] There was a process for deciding on reliability, as opposed to economic, transmission expansion.[63]

The subsequent work at the NYISO has gone much further in dealing with the practical steps for supporting merchant investment and awarding incremental FTRs.[64] 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.[65] 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 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.

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

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

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

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

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

The NYISO tariff supports 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.[66]

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."[67]

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.[68] 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 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

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[66] 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.

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

[68] 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.

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.[69] 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.[70] 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.[71]

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."[72] 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.[73] 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 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

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

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

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

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

73 This observation comes from Roy Shanker.

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.[74] Regulated transmission investment 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

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[74] 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.

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.[75] The

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[75] 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 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,

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."[76] 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.

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

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"Entrepreneurial Interconnectors and Transmission Planning in Australia," The Electricity Journal, March 2003, pp. 66-76.

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

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."[77]

Endnote:

[ii] 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).

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[77] 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.

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