Performance Incentives for Transmission

FERC's Standard Market Design should accommodate a performance-based regulation mechanism that is designed to align the interests of transmission operators with those of society by inducing the operator to trade off redispatch costs and the costs of investment and operations.

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I. Introduction

The Federal Energy Regulatory Commission's Standard Market Design Notice of Public Rulemaking (SMD NOPR) establishes a framework for markets based on locational marginal pricing (LMP). The NOPR envisions a critical role for congestion revenue rights (CRRs), which entitle holders to streams of nodal price differences. The NOPR suggests that CRRs might not only serve as hedging instruments for generation and load, but also provide incentives for efficient transmission investment and operation. With respect to investment, transmission investors would be entitled to the CRRs or CRR auction revenues engendered by their investments. With respect to operation, FERC proposes to make transmission owners (TOs) liable for congestion revenue shortfalls. To a first approximation, shortfalls occur when the energy flow between two points falls below the number of CRRs issued between the points. Hence, making TOs liable for shortfalls provides them with an incentive to maintain the availability of

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their lines. We believe that CRRs alone will not induce efficient investment or operation and that the SMD should rely on other incentives.

Given the shortcomings of the NOPR's treatment of transmission, we think that FERC should entertain other options. In particular, the SMD debate affords a unique opportunity to consider innovative forms of performance-based regulation (PBR). In some ways, LMP-based markets are conducive to PBR, because the extent and location of congestion in LMP-based markets is transparent. Incentive regulation schemes could be designed that reward TOs based on readily observable measures of transmission performance.

In the following section, we develop a general framework for assessing incentives for efficient transmission investment and operation. In Section III, we discuss the incentives embodied in the NOPR. Finally, in Section IV, we discuss a PBR that might provide better incentives. Section V offers our conclusions.

II. Incentives for Efficient Transmission Investment and Operation

An optimal incentive mechanism should meet at least two criteria: First, it should encourage TOs to equalize the marginal social benefit of reduced congestion costs and the marginal cost of reducing congestion in both the short and long run. Second, the mechanism should not discriminate between capital and operating expenditures as potential means of reducing congestion, but rather should encourage the TO to pursue whichever approach is most cost-effective.

The SMD debate affords a unique opportunity to consider innovative forms of performance-based regulation.

While it is relatively easy to define transmission costs, defining benefits is more difficult. The purpose of the transmission system is to move power from generators to consumers.

Transmission investment and increased expenditures on operations and maintenance (O&M) improve the capability of the transmission system to transfer power by reducing congestion and losses.[1] In uniform-price clearing markets such as those envisioned by the SMD NOPR, the elimination of congestion has at least two effects. First, it enables load to be met with the lowest-cost generation. This is clearly a social benefit. Second, it transfers rents from load pocket generators and generation pocket loads to load pocket loads and generation pocket generators. These transfers net to zero and no component of any of these transfers should be considered a social benefit of transmission.

We assert that reductions in ''congestion costs,'' which we equate with re-dispatch costs, are a good measure of the social benefits of transmission. In the popular and policy debate, congestion costs are frequently confused with ''congestion revenues,'' which include rents. CRRs are a claim on ''congestion revenues.'' Hence it is difficult to use CRRs to induce TOs to trade off the true social benefits of transmission and the costs of building and maintaining transmission. We elaborate on the distinction between congestion costs and congestion revenues below.

A. Congestion costs

Congestion occurs when the desired use of the transmission system is greater than what the actual transmission system can handle. For example, if participants have 110 MW that they want to get across a 100 MW transmission interface, then congestion results and generation or load schedules must be adjusted to keep the electrical system in balance. For instance, increasing generation in the importing region by 10 MW while simultaneously decreasing

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generation in the exporting region by 10 MW will reduce the desired usage of the line to an acceptable level.[2]

Clearing congestion may require decreasing the output of efficient generators and increasing the output of relatively inefficient generators. This re-dispatch is costly. Because the transmission system cannot accommodate the lowest-cost pattern of generation, generators are run out of merit order.

In the example with 110 MW of desired usage, 10 MW must be re-dispatched in order to relieve the congestion. These are real costs to society. If the marginal costs are \$2/MWh in the export region and \$4.5/MWh in the import region, then the re-dispatch cost is \$25 $(10 \times (4.5 - 2))$.

It should be highlighted that, in the LMP framework, these re-dispatch costs are not separate out-of-pocket costs for any market participant. The LMP framework adjusts the levels of the generators to achieve a security-constrained dispatch, which results in differences in locational prices when there is congestion.[3] If there is no congestion, then the nodal price differences only reflect transmission losses.

Re-dispatch costs are the true social cost of congestion. The more robust the transmission system, the lower these costs will be. However, making the transmission system more robust is not costless. An incentive scheme that encourages TOs to balance the costs of the transmission system, including O&M expenditures and investment, against congestion costs results in a socially optimal level of transmission provision in both the short- and long-run.[4]

B. Congestion revenues

Transmission systems with congestion produce transmission rents. These rents reflect the right to buy in a low-price location and sell or consume in a high-price location. These are not real costs to society, but represent transfers between different groups. Congestion revenues and congestion costs both stem from locational price differences reflecting differences between generation costs at different locations, but they are only loosely correlated with each other. In the example above (with constant marginal costs assumed in each area), the benefit of transporting the power between areas is the product of the difference in prices and the quantity shipped. In this case, they are \$250 $(100 \times (4.5 - 2))$, i.e., the size of the tie (100 MW) multiplied by the difference between the prevailing prices on each side of the interface. In the LMP framework, these rents are popularly known as ''congestion revenues.''

Clearing congestion may require decreasing the output of efficient generators and increasing the output of relatively inefficient generators.

Figure 3 in Appendix I contains a more general graphical illustration of congestion costs and revenues.

III. CRRs Provide Insufficient Incentives for Efficient Investment and Operation

As discussed above, CRRs are a central element of the SMD NOPR. Because congestion revenues are poorly correlated with the social benefits of transmission, mechanisms based on congestion revenues will not induce efficient investment or operation.[5]

A. CRRs alone will not induce efficient investment

The SMD NOPR is unclear with respect to how transmission will be financed. It seems to envision an important role for CRRs and a ''backstop'' role for regulated transmission financed from access charges. The value of CRRs resulting from a transmission investment may diverge substantially from an investment's social value or value to consumers, so other revenue streams will be necessary to finance ''market-based'' transmission investment. It may be difficult for transmission investors to tap these non-CRR revenue streams.

1. Transmission investment that eliminates congestion results in CRRs that are worthless. Given the nature of transmission investment, the optimally sized upgrade will seldom exactly match the magnitude of the economic need that the ITP's (independent transmission provider) planning process has identified. This problem of "lumpy" transmission investment means that many transmission upgrades are sufficiently large to alter congestion prices. In this context, a system that rewards transmission investment with CRRs forces TOs to consider the impact of their investments on congestion prices in the same way that a monopolist or oligopolist in any market considers the impact of his output on the price he receives. This generally leads to under-production and under-investment relative to the socially efficient level.

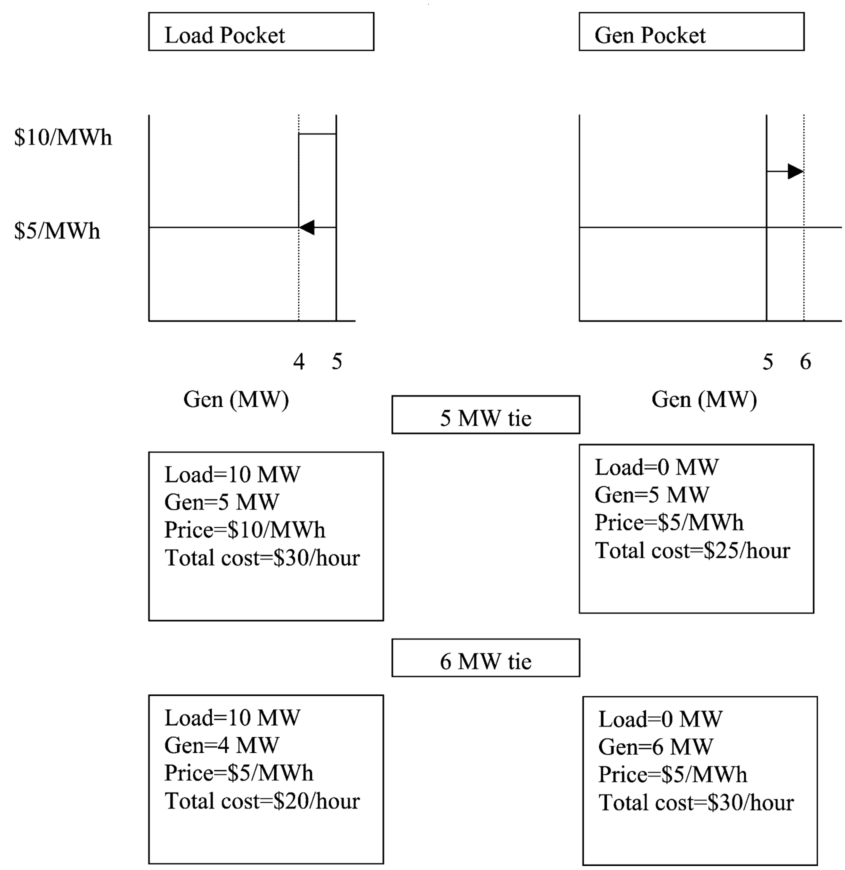

Figure 1: Transmission Expansion Example

Consider the example shown in Figure 1, a transmission line joins a generation pocket to a load pocket. There are 10 MW of load in the load pocket. There is no load in the generation pocket. The figure shows the supply curves for both areas. The solid vertical lines indicate the level of production in each area in the presence of a 5 MW line joining the two areas, and the dotted vertical lines indicate the levels of production in each area in the presence of an expanded 6 MW line. With a 5 MW line, total generation costs in each hour are $55/hour. Congestion revenues are the product of the flow between the two areas and the price difference, i.e., 5 MW × ($10/MWh – $5/MWh) = $25/hour. A 1 MW expansion of the path joining the two areas reduces the total cost of generation to $50/hour and equalizes prices in the two zones so that there are no congestion revenues. No one would build the expansion, even if it were costless, if the only reward were the resulting value-less CRRs, despite the fact that at a cost of transmission below $5/hour, the resulting decrease in generation costs would warrant the investment.

Appendix I contains a more general graphical treatment of this issue.

2. It is difficult to assign CRRs "correctly." The SMD NOPR outlines mechanisms for the creation and allocation of CRRs. It is important to recognize that there is a certain amount of arbitrariness in the process of creating and allocating CRRs. The ITP must perform simulations to determine the appropriate number of CRRs, i.e., the number that meet the simultaneous feasibility test. These simulations

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require a large number of assumptions about which there may be legitimate differences of opinion. Moreover, the CRR calculations can be path-dependent in the sense that the location and number of CRRs assigned to a particular investment may depend on all previously approved investments.

To date, different ISOs have performed these types of calculations very differently. For example, the creation of FTRs in PJM is based on a complete AC-flow model that reflects all current and planned investments. The NYISO calculation is based on a cruder model that is updated less frequently. If the calculation of what CRRs are simultaneously feasible is not done correctly, fewer CRRs than congestion revenues can support may be created. At the opposite extreme, persistently under-funded CRRs may be created. This issue is critical given FERC's expressed preference for forcing TOs to finance congestion revenue shortfalls (and potentially share in congestion revenue surpluses).[6]

Given these problems with the CRR creation and allocation process, it is unclear that transmission investors will actually be granted CRRs corresponding to the additional capacity due to their investments. In general, this potential mismatch between the rewards for and benefits from transmission investment will lead to inefficient investment.

These problems are likely to be especially severe for small upgrades to existing systems, particularly in meshed networks. Experience in other markets, including the U.K., shows that these types of investment are among the most cost-effective, but they are precisely the types of investment for which CRR assignments based on conventional simultaneous feasibility tests are most error-prone.

The potential mismatch between the rewards for and benefits from transmission investment will lead to inefficient investment.

The recently approved Regional Transmission Expansion Plan of ISO New England provides a concrete illustration of the different ways that transmission capacity can be expanded.[7] Table 1.1 of that report lists about 30 projects of which 26 are small, i.e., less than $20 million in cost. Most of these do not involve new lines. The majority involve rebuilding existing lines or adding network equipment (such as capacitors, transformers, or breakers). Because these small projects are all embedded in existing systems, the process of creating and assigning them incremental CRRs will be far from precise and may not correspond to the increased capacity that each adds to the network.

3. It may be difficult for transmission investors to capture other benefit streams resulting from transmission investment. The NOPR is agnostic about other (non-CRR) revenue streams that might be used to finance transmission investment. Efficient investment requires that transmission investors share in the full surplus resulting from their investments. One of the largest benefits of transmission investment is the decrease in energy costs for consumers on the ''wrong'' side of a constraint that is relaxed.[8] TOs, energy consumers, and generators may be able to share these surpluses through contracts. There are at least two reasons why such contracting may not occur.

a. Free-riding. Transmission investment has public good aspects. The benefits of a specific transmission investment may be diffuse, and, once a project is built, it may be impossible to deny any specific beneficiary the project's benefits. Consequently, each beneficiary has an incentive to avoid bearing his share of the project's costs, so long as his non-participation does not prevent the project from being built. For example, if one specific load-serving entity (LSE) were willing to commit to finance a transmission project based on

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the energy savings from the consequent elimination of congestion, another LSE could offer even lower retail prices by avoiding his appropriate share of the costs of the transmission upgrade. More generally, even when all beneficiaries are willing to participate in the financing of a project, when the beneficiaries are diverse and the benefits are distributed asymmetrically, it may be difficult for beneficiaries to reach agreement about benefit shares and hence cost shares. This is a longstanding problem in the economics literature on public goods and mechanism design, for which there is no perfect solution.[9]

One partial, but imperfect, solution to this problem is traditional rate-making. Although traditional embedded cost tariffs often do not induce optimal economic behavior and there is no guarantee that the regulatory process chooses the "right" transmission projects, traditional tariffs can force all users to share the costs of the investments from which they benefit and prevent free riding.

b. Political economy. Transmission investment has important distributional impacts. While society as a whole may benefit from the elimination of congestion, some parties may be harmed. In general, transmission investment effects rent transfers from load pocket generators and generation pocket consumers to load pocket consumers and generation pocket generators.[10] In addition, decisions about transmission investment are and will continue to be made in a political context. A load center load and a generation pocket generator cannot simply decide to build a line linking them. Their decision will be subject to scrutiny by not only an ITP or

its analog but also state and federal energy and environmental regulators. In this type of environment, the "losers" from transmission investment can be expected to expend up to the amount of the rents that they stand to lose to block transmission investment. This rent dissipation is wasteful. Moreover, it may block good projects from being built. This is particularly true in cases where the benefits of existing congestion are highly concentrated—e.g., a few load-center generators may greatly benefit from an existing constraint—but the benefits of eliminating congestion are relatively diffuse—e.g., slightly lower average energy charges for end users paying rates that are not geographically or temporally differentiated.

The effect of transmission investment on producer and consumer surplus can be complicated and counter-intuitive. Ongoing debates about upgrades to Path 15, the main transmission corridor between Northern and Southern California, are a good illustration of this point. At least one study purports to show that expanding Path 15 would lower some component of consumer surplus. This claim is based on the results of a simulation that shows that, in periods of south-to-north congestion, the upgrade would raise day-ahead prices in the South by more than it would lower prices in the North.[11]

Regional opposition to SMD itself, particularly in the Pacific Northwest and the South, further underscores the political economic problems associated with transmission investment. While regional opposition to SMD generally takes the form of opposition to broader regional markets rather than opposition to transmission expansion *per se*, its motivation is related. Generation pocket consumers will resist attempts to export "their" cheap power to higher-priced areas.

Any process for transmission planning and investment, including regulation, is subject to these types of political economic problems. Regulation at least provides a framework for bringing these conflicts to closure.

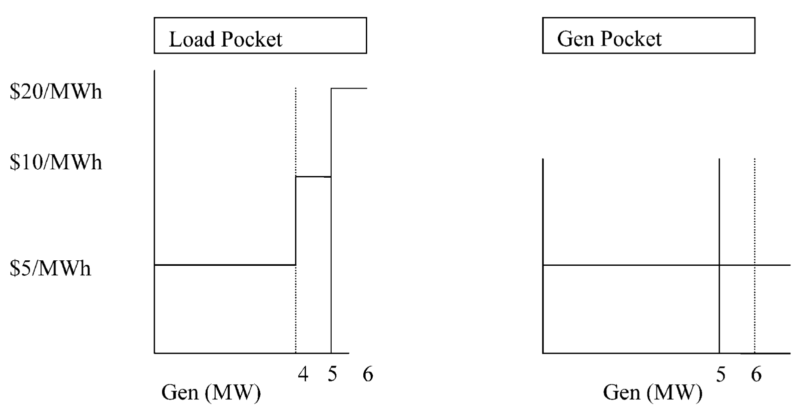
B. CRRs alone will not induce efficient operation

The SMD NOPR mandates fully funded CRRs and makes TOs responsible for congestion revenue shortfalls. It invites comments on whether TOs should be allowed to share in congestion revenue surpluses. While there is an ostensible fairness to allowing TOs to share in congestion revenues surpluses if they are going to be punished for congestion revenue shortfalls, neither incentive alone or in combination will necessarily lead to efficient operation. In addition, to the extent that shortfalls may result from forces beyond TOs' control, shortfalls provide no incentives. Even if shortfall liability provided the correct incentives, shifting this risk onto TOs forces them to assume a risk without compensation relative to the status quo. If FERC is intent on making TOs face shortfall liability, they should address this rent-transfer.

1. *Incentives*. In the short run, an efficient incentive encourages the transmission operator to trade off the costs that he can control in the short run, such as O&M, against re-dispatch costs. This section illustrates the tenuous relationship between congestion revenue shortfalls and re-dispatch costs using a set of stylized examples. This relationship depends on the shape of supply curves in different regions, whether or not the TO is entitled to surpluses in addition to being liable for shortfalls, and the volume of CRRs relative to the capacity of a given line. The examples are based on Figure 2, which is a modified version of the figure used in our discussion of transmission expansion.

Suppose that a 6 MW line linking load and generation pockets is in place and that CRRs for the entire capacity of the line have been issued. Further, suppose that a partial outage reduces the available transfer capability (ATC) of the line to 5 MW.[12] In a region where CRRs are fully funded, the ITP will collect \$25/hour in congestion revenues but will owe \$30/hour to CRR holders. If the TO is liable for the shortfall of \$5/hour, he will spend up to \$5/hour to eliminate the shortfall. Given that the re-dispatch costs are \$5/hour, in this specific case, shortfall liability provides the TO with the correct incentive.

Now, suppose that the outage is 2 MW so that 4 MW of transfer capability are available. In this case, in addition to the 1 MW of \$10/MWh generation, an additional 1 MW of \$20/MWh generation is required to meet load in the load pocket. The nodal price difference is \$15/MWh so 4 MW $\times$ \$15/MWh = \$60/hour of congestion revenues are collected and the shortfall is 2 MW $\times$ \$15/MWh = \$30/hour. However, the re-dispatch costs are only 1 MW $\times$ (\$10/MWh − \$5/MWh) + 1 MW $\times$ (\$20/MWh − \$5/MWh) = \$20/hour. The TO would be willing to spend up to \$30/hour to eliminate shortfalls, but from a social standpoint, it would be inefficient for him to spend any more than \$20/hour.



Summary of shortfalls under different availability scenarios

ATC	CRRs	Load center load	Gen center load	Nodal prices: Load center	Nodal prices: Gen center	Congestion revenues	CRR payments	Re-dispatch costs	Shortfall (surplus)
5	6	10	0	10	5	25	30	5	5
4	6	10	0	20	5	60	90	20	30
4	3	10	0	20	5	60	45	20	-15
6	3	10	0	5	5	0	0	0	0

Figure 2: Shortfall Example

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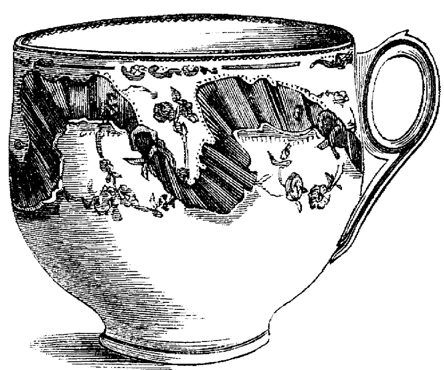
Finally, consider another case similar to the previous one in which only 3 MW of CRRs are issued. Congestion revenues are sufficient to cover CRR obligations, even with a 2 MW outage. Assuming that the TO is only liable for shortfalls but does not receive any share of surpluses, he has no incentive to restore the full capability of the line. Clearly, this is not the right incentive. Allowing the TO to share in surpluses does not fix the problem. For example, if the TO succeeds in restoring the line to full capacity, the nodal price difference is eliminated so there is no CRR surplus. On the other hand, if he does nothing, he receives a surplus of $15/hour. The right incentive would induce the TO to restore the line to full capacity so long as the costs of doing so are less than the re-dispatch costs of $20/hour.

2. TOs may have limited control over CRR shortfalls. The preceding discussion assumes that the TO is able to influence availability through his actions. If this is not the case, then shortfall liability provides no incentive for efficient operation. The extent to which a TO can influence the availability of his own lines remains an empirical question.

The SMD contemplates a substantial separation of the ownership and control of transmission. Moreover, the SMD envisions broad regional ITPs incorporating the transmission assets of many different TOs. In this context, a TO whose assets are small relative to the whole system may have little control over the available transfer capability of his own transmission. The actions of the ITP, other TOs, and exogenous forces clearly will affect ATCs and hence the TO's ability to collect the congestion revenues for which he is liable.[13]



Generation outages can also have a large impact on path ratings and hence shortfalls. This effect can be especially pronounced when large base-load units in load centers, such as nuclear plants on the East Coast, experience outages. Clearly, the TO cannot control such events and should not be penalized when they occur.

In fact, shortfalls may be a better measure of ITP than TO performance. ITPs will perform the simulations that determine what CRRs are simultaneously feasible. As discussed above, the accuracy of these simulations will have a major impact on whether CRRs are over- or under-funded. In addition, ITPs may have considerable discretion over what CRRs are offered. Some ITPs may choose to offer limited CRRs that essentially grandfather existing transmission rights. Others may create rights that meet or exceed all simultaneous feasibility constraints through auctions or other allocation mechanisms. In addition to controlling how CRRs are issued, ITPs will also control dispatch. Dispatch is another factor beyond the TO's control that can have a significant impact on path ratings and hence shortfalls.

To the extent that participation in CRR auctions is limited, CRR auction prices may not reflect their value. As long as CRR prices do not converge to their "true" values, market participants will demand more comprehensive CRRs that are more likely to be under-funded. CRR bidders' ability to affect the auction process is yet another factor beyond the TO's control that may influence shortfalls and surpluses.

Even if TOs can influence shortfalls through their actions, other factors may prevent them from taking the necessary actions. For example, aspects of the SMD NOPR that require ITPs to issue RFPs for even minor upgrades may limit or slow TOs from undertaking the investments necessary to reduce shortfalls.

3. The NOPR's CRR proposal shifts costs to TOs without any corresponding rewards. Not only does forcing TOs to bear the risk of

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congestion revenue shortfalls not provide appropriate incentives for efficient operation, but it also forces TOs to bear a risk that they do not currently bear without any corresponding reward. Given that transmission will be instrumental in guaranteeing smoothly functioning restructured markets, it probably was not FERC's intent to punish TOs.

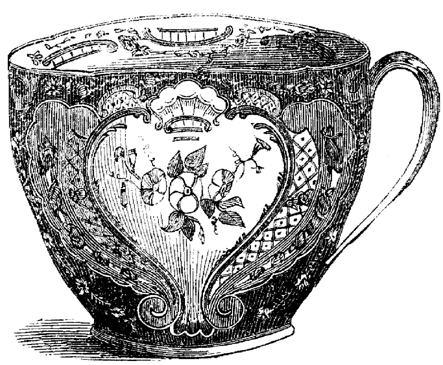
If FERC ultimately decides that TOs should bear the risk of congestion revenue shortfalls, it could compensate the TOs for this assumption of risk in a variety of ways. These approaches might involve TOs receiving up-front payments to fund pools from which congestion revenue shortfalls could be financed. Any funds in the pools that are not paid out would revert to TOs, providing them an incentive to take actions within their control to maintain the availability of transmission so that shortfalls are reduced. A fraction of CRR auction revenues might be used to establish such pools.

Equivalently, CRRs could be partially funded, i.e., they would pay only the congestion revenues that are collected. If CRRs were partially funded, TOs could sell supplemental contracts that pay holders the difference between the payouts of partially and fully funded CRRs, in essence shortfall insurance. This approach would allow the market to price expected shortfalls.

Alternatively, ITPs could issue CRRs in sufficiently limited quantities that shortfalls would be unlikely.[14] However, this removes the incentive that shortfall liability gives the TO to keep the transfer capability of his assets as high as possible.

C. CRRs may not provide balanced incentives for investment and operation

As discussed in Section II, an optimal incentive should not discriminate between capital and operational expenditures. In this section, we have described how incentives based on CRRs are unlikely to provide the right incentives for investment or operation. For the reasons discussed in Section III.A, if CRRs and ''the market'' are the only incentives for transmission investment, there is likely to be too little investment. As discussed in Section III.B, using shortfall liability may lead to expenditures on O&M that are too low or too high from a social perspective. Under plausible assumptions (corresponding to something like the second example in Section III.B.1), shortfalls exceed re-dispatch costs and shortfall liability induces excessive expenditures on O&M. The NOPR may have a bias towards operational rather than capital expenditures, but the bias is ambiguous and depends on assumptions.



IV. Developing an Appropriate PBR for Transmission

The SMD NOPR assigns a backstop role to regulated transmission investment. Because of the problems outlined in Section III, a non-trivial fraction if not the majority of all transmission investment is likely to be made on a regulated basis under SMD. Consequently, we think that SMD should give much greater attention to the form of transmission regulation.

In particular, the SMD should accommodate a performance-based regulation mechanism. Such a mechanism can be designed to align the interests of the TO with the interests of society, i.e., a PBR can be designed to induce the TO to trade off re-dispatch costs on the one hand, and the costs of investment and operation on the other hand. Such a PBR will meet all of the criteria enumerated in Section II. In what follows, we outline a framework for such a PBR and briefly touch on some of the implementation issues.

A. Proposed PBR mechanism

The basic structure of the mechanism is as follows. The TO

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is allowed to collect a transmission fee based on the expected levels of demand, the revenue requirement of the grid, and re-dispatch costs. The idea is to set the price cap sufficiently high that the TO recovers the revenue requirement and congestion costs, in expectation. However, the TO must also rebate realized re-dispatch costs. Thus, the TO has the incentive to make actual re-dispatch costs lower than expected re-dispatch costs since it gets to keep the difference.

We define the following variables:

P is the transmission fee paid for all removals from the transmission system, either to consumers or to interconnected regions,

Q is the energy delivered by the transmission system,

C_{RD} is the re-dispatch costs on the system,

C_G is the costs (revenue requirement) of the grid, and

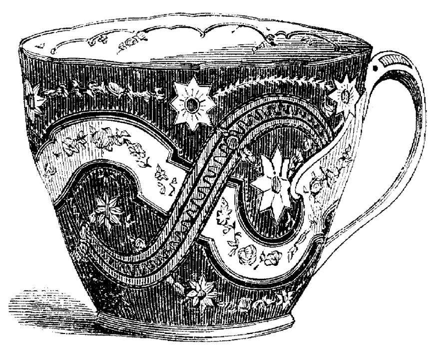
$E(\cdot)$ is the expectations operator.

If the price cap is set so that $P = [E(C_G) + E(C_{RD})]/E(Q)$, then the TO's solvency may be at risk since actual congestion costs may turn out to be much higher than expected. To avoid this occurrence, it may be necessary to use a higher value for the price cap. Other risk-mitigating alternatives are discussed below.

This formulation requires the TO to rebate customers for actual re-dispatch costs to offset the expected re-dispatch costs that those customers pay in transmission rates. As noted above, such an approach will produce downward pressure on actual re-dispatch costs as the TO takes action to reduce congestion, resulting in savings to customer.

The TO's profits are $P \cdot Q - (C_{RD} + C_G)$ or $[Q/E(Q)][E(C_G) - C_G + E(C_{RD}) - C_{RD}]$.

If actual congestion costs are lower than expected, the TO



keeps the difference. If actual congestion costs are higher than expected, the TO loses the difference. The same is true for the cost of the grid so that the TO is rewarded for his own operational efficiency.[15]

Most importantly, this mechanism allows the TO to balance re-dispatch costs (C_{RD}) against the costs of the grid (C_G), as is socially optimal. Further, because capital and operational expenditures enter C_G symmetrically, the TO has the incentive to balance them efficiently.

1. Measuring re-dispatch costs. Re-dispatch costs are the difference between actual generation costs and costs calculated from a counter-factual dispatch based on a reference transmission system.[16] The calculation of generation costs in the counter-factual case requires the ITP to perform an additional simulation in addition to the one used to determine the actual security-constrained dispatch.[17]

This type of counter-factual calculation has been used in other jurisdictions to calculate and allocate congestion costs.[18] One potential drawback of this method is that it equates bids with costs. If bids do not reflect costs then a dispatch that minimizes the ITP's procurement costs may not minimize the social cost of generation. This can happen when a generator with a relatively efficient portfolio of generation bids strategically to influence prices. The dispatch algorithm may reject this generator's highest bids but accept lower bids from a generator with less efficient generation whose bids reflect his costs. In a well-functioning competitive market, bids should reflect costs. In addition, strategic bidding can also be discouraged through the types of market monitoring envisioned by the NOPR. On the other hand, a mechanism tied to re-dispatch costs based on bids that reflect market power provides the TO an incentive to eliminate both congestion and the ability of generators to exercise market power.

2. Mitigating risk. When congestion costs are large and variable, or when an

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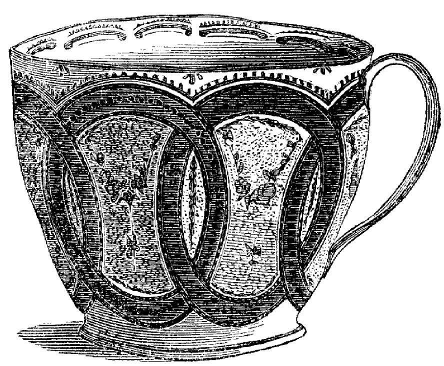
extraordinary event occurs, there may be periods in which the TO's liability for congestion costs threatens its solvency. This problem can be addressed in several ways.

First, the PBR might exclude congestion costs due to events that are clearly beyond the TO's control, such as generation outages. One method for removing the impact of generation outages from the PBR involves using an alternative measure of re-dispatch costs. This measure captures the difference between generation costs given the actual state of the transmission system and ''expected'' generator availability to generation costs with infinite transfer capability (or some other reference transmission system) and ''expected'' generator availability. This calculation requires assumptions about expected availability and proxy bids for units on outage that do not submit bids.

Second, the transmission tariff charges can be set sufficiently high to compensate the TO for the risk of extraordinary losses due to exceptional events. This provides a more symmetric risk/reward profile to TOs that are assuming the obligation to pay for congestion costs under any contingency. Note that the TO's incentives to invest in and operate his system efficiently do not depend on the level of the cap.

Third, hedging instruments can be used to protect TOs against extreme events. One such instrument is a ''collar.'' A collar limits the TO's profits to a specific range. In return for protection against extreme losses, the TO foregoes extreme profits. The main problem with collars and other similar instruments that limit TO risk is that they weaken incentives. Once the TO expects to reach the upper limit of a collar in a given year, the TO no longer has



the incentive to make operational or investment decisions that reduce congestion costs.

B. Potential problems

1. Transmission bias. The SMD expresses concerns about a ''transmission bias'' to solving congestion problems that might result if TOs are allowed to assume certain ITP functions or if regulated transmission is given too prominent a role.[19] Given the woeful state of existing U.S. transmission infrastructure, the risks of over-investment are remote and the costs low relative to the total costs of delivered energy.[20] In addition, generation will continue to be easier to site and will be subject to less scrutiny under the regional planning process envisioned by the NOPR.

2. Footprint. The type of PBR that we have outlined is likely to be most effective when each TO controls a relatively large part of an integrated system. Transmission investment may produce benefits far from where it occurs. If each operator's PBR is tied to congestion costs on his sub-system, he may fail to undertake investments that benefit other parts of the system. In addition, joint ownership and overlap of assets is likely to make the mechanics of the PBR unduly burdensome. Capital and congestion cost allocation issues will be non-trivial.

Hence, the effective implementation of PBR may require further consolidation of the operation if not the ownership of transmission assets.[21] We hope that SMD will at least not hinder such consolidation even if it does not explicitly encourage it.

3. Benchmarking. In Section IV.A.1, we discuss how to measure actual re-dispatch costs. Another critical input to the PBR is expected re-dispatch costs. Expected re-dispatch costs can be based on historical re-dispatch costs, as in the U.K., or can be calculated from simulations.

There is one main problem associated with equating historical and expected re-dispatch costs, especially in the U.S.

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context. Many organized markets are immature or will only come into existence after SMD is implemented. Hence, the data necessary to calculate historical re-dispatch costs for many parts of the country may not exist. In the absence of historical re-dispatch costs, it would be necessary to rely on other methods to set the tariff in the first few years of implementation. Alternatively, the implementation of the PBR could be delayed until the data necessary to calculate historical re-dispatch costs are available.

One aspect of PBRs based on historical re-dispatch costs is that they can be designed to self-correct in the following sense: An unforeseen event, such as an uncontrollable line outage, might cause a TO to lose money in a given year. If the benchmark is designed to adjust upwards as well as downwards, the event lowers the benchmark, i.e., raises expected re-dispatch costs and the amount the TO receives in transmission revenues. Similarly, if congestion costs fall below the benchmark in a given year because of a reduction in the frequency and magnitude of uncontrollable events, the benchmark rises, i.e., expected re-dispatch costs fall as does the amount the TO receives in transmission revenues.

Alternatively, expected re-dispatch costs can be calculated from simulations. Exactly how these simulations would be performed would be the topic of extensive debate. For example, should the simulations use full chronology or ''representative'' periods? Should the simulations use expected generator and line outages or should outages be modeled in a Monte Carlo framework that more accurately captures the non-linearity of their impact?

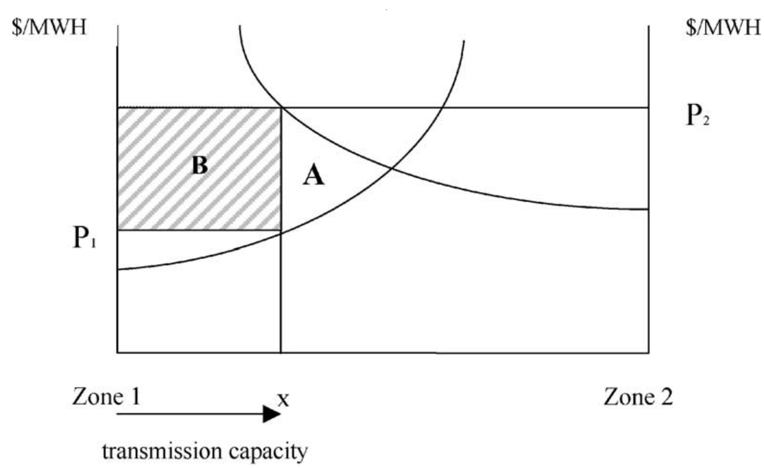

Figure 3:

V. Conclusions

The SMD NOPR attempts to provide TOs with better incentives for efficient investment and operation. While we agree with the spirit of the SMD NOPR, we think that it contains the wrong incentives for transmission. In particular, the aspects of the NOPR that tie the compensation of TOs to congestion revenues are unlikely to result in efficient performance. As FERC lays the groundwork for the wholesale power markets of the future, we hope that it will give further consideration to incentives for transmission. We have proposed

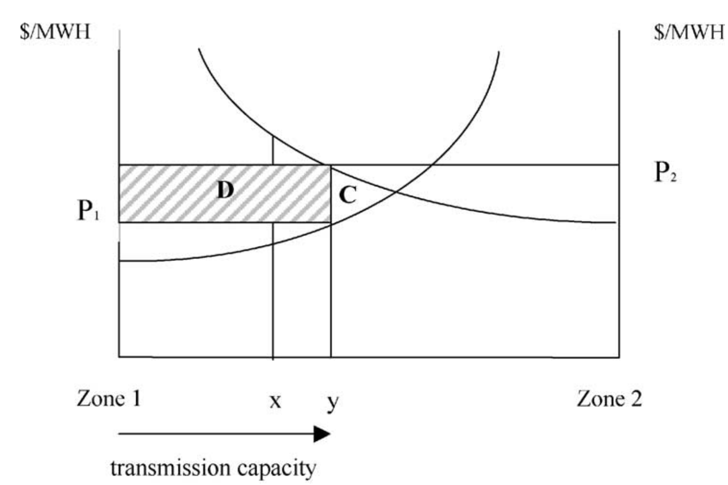

Figure 4:

one general approach that we think could prove fruitful.■

Appendix I. Graphical Illustration of Re-Dispatch Costs and Congestion Rents

Figure 3 shows graphically the difference between re-dispatch costs and congestion rents. This figure shows the supply curves for two geographically separate areas, Zone 1 and Zone 2. The supply curve for Zone 2 is shown reversed from the usual representation (which is used for Zone 1), by having the quantity increase from right to left, rather than left to right. The length of the horizontal axis represents the quantity demanded in Zone 2. We assume there is no demand in Zone 1. If there were adequate transmission capacity between the two zones, the efficient allocation of generation between the zones would be where the two supply curves cross since that allocation equates marginal costs between the zones.

With transmission capacity of x linking the zones, the export area (Zone 1) can only produce up to price P_1. Similarly the import area, Zone 2, must increase its output to price P_2. The re-dispatch costs are shown by the triangular area A, which is the difference in costs as Zone 1 supply is reduced and Zone 2 supply is increased compared to the unconstrained case. The congestion rents are shown as the rectangle B, which is the price difference between zones, multiplied by the capacity of the link. The congestion rents reflect the ability to sell power that costs P_1 for the higher price of P_2.

Next we show in **Figure 4** what happens when the transmission capacity between the zones is expanded from x to y. This reduces the re-dispatch costs from area A in Figure 3 to area C in Figure 4. The price difference between the zones decreases in Figure 4, with P_1 going up and P_2 going down. Congestion rents after the expansion are the rectangle D. The congestion rents may be larger or smaller with the expansion than before. The relative shape of the supply curves and the size of the expansion will determine whether the congestion rents get larger or smaller after the expansion. In general, as the expansion gets closer to eliminating the congestion, the congestion rents will get smaller since the energy price difference becomes very small.

Endnotes:

1. We do not explicitly address losses in what follows. Losses are small relative to re-dispatch costs and the mechanisms considered herein could be modified to incorporate losses without changing our conclusions.

2. Alternatively, increasing the load in the export region and decreasing it in the import region would also clear the congestion. This also entails costs.

3. In some markets without LMP, such as the U.K. market, these costs can be explicit out of pocket costs for the system operator.

4. This is the goal of the PBR scheme that we discuss in Section IV.

5. Paul Joskow and Jean Tirole independently have examined some examples similar to the ones discussed below in *Merchant Transmission Investment*, 2003, available at http://econ-www.mit.edu/faculty/pjoskow/files/Merchant.pdf.

6. See Section III.B for further discussion of this issue.

7. See ISO-New England RTEP02, Nov. 7, 2002.

8. Analogously, generation owners that are separated from load by transmission constraints also benefit from transmission expansions.

9. For a general treatment of these issues, see JEAN-JACQUES LAFFONT, FUNDAMENTALS OF PUBLIC ECONOMICS (Cambridge, MA: MIT Press, 1998). It may be possible to devise an auction that would induce the beneficiaries of transmission investment to truthfully reveal their own estimated benefits from a project. One such auction is known as a Groves Mechanism. If the sum of beneficiaries valuations or bids exceeds the cost of a project, the project is built and shares of its cost are assigned based on bids. Auction participants are induced to reveal their ''true'' valuations by requiring them to pay the amount by which their bids are pivotal. If the sum of all bids but one exceeds the cost of the project, the one remaining bidder pays nothing, regardless of his bid. On the other hand, if the sum of all bids but one fall short of the cost of the project, the project is built if the remaining bidder is willing to make up the difference. This type of mechanism prevents bidders from shading their bids too high in order to insure that a project is built, or too low in order to minimize their cost shares. The main problem with this mechanism is budget balance. Nothing guarantees that the sum of the payments from bidders will exceed the cost of the project, even if the sum of bidders' valuations exceeds the cost of the project. In addition, when coalitions of bidders can explicitly or implicitly collude, the Groves Mechanism will not necessarily lead to an efficient outcome. For example, if any two bidders agree to set bids individually equal to the cost of the

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project, neither party pays anything and the project is built. For a non-technical description of the Groves Mechanism, see http://faculty-gsb.stanford.edu/bulow_class/E203/templates/PDF%20Files/102WillingnesstoPay.pdf. The Groves Mechanism is but one of the many imperfect mechanisms designed to address the public goods funding problem.

10. In the example of Section III.A.1, the hypothetical transmission upgrade of 1 MW, reduces payments by load from \$100 to \$50 hour. Part of this decline corresponds to the decline in total incremental generation costs of \$5/hour, but the remainder represents a transfer from load pocket generators and the holders of pre-upgrade transmission rights.

11. See the California ISO's *Path 15 Upgrade Cost Analysis Study*, Feb. 2001.

12. In the examples that follow, we assume that the market-clearing price is the lowest price at which the vertical demand curve intersects the supply curve.

13. This issue has been discussed at a recent FERC technical conference. *See Grid Operators Warn FERC on Outage Liability Rules, Reuters,* Dec. 11, 2002.

14. See the discussion in Section III.A.2.

15. There is likely to be less variance in the costs of the grid.

16. It is common to estimate re-dispatch costs as the difference between actual generation costs and the costs of generation assuming no congestion, i.e., infinite transfer capability. Alternatively, re-dispatch costs can be calculated as the difference between actual generation costs and generation costs assuming average or expected path ratings.

17. Another potential measure of congestion and losses is based on the components of nodal energy prices in the LMP framework. Each nodal price is composed of a marginal energy component, a loss component, and a congestion component. This measure depends on the congestion and loss components of energy prices as a way to measure aggregate congestion and losses. The measure would sum across nodes the congestion and loss component values of the nodal price energy weighted by the quantities injected or removed from the system at each node. Less congestion means lower congestion components of prices; similarly, fewer losses mean smaller lose components. While it is true the magnitude of the separate LMP components are dependent on which bus has been designated the reference bus, this measure should be consistent over time as long as the same reference bus is used. The calculation of this measure of losses and congestion should be readily adaptable from the security constrained dispatch algorithms ITPs use to calculate LMPs.

18. In particular, similar methods have been used in the U.K. market to calculate congestion uplift.

19. For example see Shmuel Oren, George Gross, and Fernando Alvarado, *Alternative Business Models for Transmission Investment and Operation*, in DOE's *National Transmission Grid Study*, 2002.

20. See Paul Joskow's comments on Order 2000 for a more thorough exposition of the relative risks of over- and under-investment in transmission.

21. The recently-approved GridAmerica ITC forms a precedent for how control might be consolidated through contracts in the absence of consolidation of ownership.

❖ *Meetings of Interest* ❖

Conference	*Date*	*Place*	*Sponsor*	*Contact*
2003 Spring Electric Energy Conference	May 4–6	Chaparral Suites Resort, Scottsdale, AZ	Rocky Mountain Electrical League	http://www.rmel.org 303-695-0089
Energy Risk Management	May 19–20	Sheraton San Diego	Energy Management Institute	www.energyinstitution.org
EEI's Annual Convention/Expo	June 1–4	Hilton Hawaiian Village, Honolulu, HI	Edison Electric Institute	www.eei.org
APPA National Conference	June 14–18	Opryland Hotel, Nashville, TN	American Public Power Association Paulette Kum	www.appanet.org 202-467-2941
IEEE/PES T&D Conference & Exposition	Sept. 7–12	Dallas	Institute of Electrical and Electronic Engineers	www.ieee.org 817-215-6363
Association of Edison Illuminating Companies Annual Meeting	Oct. 15–18	White Sulphur Springs, WV	Association of Edison Illuminating Companies	www.aeic.org 205-257-2530
7th International Energy Transmission and Distribution Conference and Exhibition	Nov. 16–19	Adelaide, Australia	Waldron Smith Management	Tel: +61 3 9645 6311; Fax: 61 3 9645 6322 E-mail: info@wsm.com.au http://www.d2003.net/index.htm

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