

**CONGESTION REVENUE RIGHTS:
IMPLICATIONS FOR STATE PUBLIC UTILITY COMMISSIONS**

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I. Introduction

On July 31, 2002, the Federal Energy Regulatory Commission (FERC) released a Notice of Proposed Rulemaking concerning Open Access Transmission Service and a Standard Electricity Market Design.¹ (Hereafter, this Notice of Proposed Rulemaking is referred to as the SMD NOPR.) The length of the SMD NOPR is 339 pages plus Appendices A through G. The text of the SMD NOPR is divided into ten sections that cover in part the need for the reform of the current reform of the United States electricity industry, a proposed remedy of the problems facing the reformed electricity industry, and a set of implementation guidelines.²

FERC has mentioned at least ten reasons for taking action to implement an open access transmission service and a Standard Market Design.³ The focus of this exploratory

¹ Federal Energy Regulatory Commission, *Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design*, Notice of Proposed Rule Making, Docket No. RM01-12-000, July 31, 2002.

² The need for reform is covered from page 22 through page 65 in the SMD NORP. The proposed remedy is presented in varying level of detail from page 66 through page 316. The partial set of implementation guidelines cover page 317 through page 324.

³ The ten reasons that FERC has listed in the SMD NORP are: (1) Assurance of adequate and reliable supplies of electric energy at a just and reasonable wholesale price at p.1. (2) Continuation of the construction of a foundation for regional transmission institutions at p. 2. (3) Continuation of the construction of a foundation for a competitive wholesale electricity market at p. 2. (4) Removal of significant impediments to the realization of competitive wholesale markets at p. 2. (5) Removal of significant impediments to the construction of adequate infrastructure to meet electric energy demand at p. 2. (6) Elimination of unduly discriminatory transmission practices at p. 2. (7) Elimination of inconsistent wholesale market designs at p. 2. (8) Elimination of inconsistent administration of short-term wholesale energy markets at p. 2. (9) Remedy of undue discrimination at p. 3. (10) Establish a standardized transmission service and establish a standardized wholesale electric market design in order to provide a level playing for all entities that seek to participate in wholesale electric markets at p. 3.

analysis is Congestion Revenue Rights (CRRs) and their function in the Standard Market Design (SMD).⁴ The SMD NOPR establishes that the role of CRRs in this context is to assist in providing assurance of adequate and reliable supplies of electric energy at just and reasonable wholesale prices.⁵ To this end, CRRs are designed to provide price certainty for a subset of transmission customers who purchase open access transmission service. In addition to price certainty, CRRs are intended to provide a subset of transmission customers with a non-price vehicle for “buying through” transmission congestion regardless of the value of congestion (VOC).

Locational marginal pricing (LMP) is used as a valuation vehicle for FERC’s measure of VOC. Simply put, LMP produces readily observable prices that are used to calculate the VOC between a receipt point and a delivery point. The VOC is treated as a quantified congestion charge that provides all transmission customers with economic signals for the deferral of their use of the transmission network.

FERC’s consumer constituency—the transmission customer—wants low wholesale prices. The state public utility commission’s consumer constituency—the retail electricity customer--wants low retail prices. These two desires would be consistent with each other and achievable if the United States electricity industry indeed was competitive.⁶ There is a growing body of evidence that demonstrates that the United States electricity industry is subject to significant market-power abuses hence is not competitive. The exploratory analysis presented herein will focus on the viability of CRRs, their implications for a competitive electricity industry for the United States and the potential for CRRs to increase or decrease wholesale and retail prices regardless of whether there is retail choice in a state regulatory jurisdiction.⁷

⁴ Although CRRs are described or referred throughout the entire text of the SMD NOPR the following sections contain the most in-depth explanation and discussion of this new approach to “congestion management” in a more decentralized electricity industry. The systematic mention of CRRs occurs in Section III.B. 3. The next systematic mention is Section IV.C.10. The most detailed explanation of CRRs occurs in Section IV.E, in particular, Section IV.E.3. The allocation of CRRs is discussed in Section IV.H.2.

⁵ SMD NORP, p.1.

⁶ It is sometimes useful to write: “Given a competitive United States’ electricity industry *in the sense of an economist*”. This means that any horizontal market power or vertical market power that is present in the electricity industry is negligible. In this instance, low wholesale electricity prices would be translated into low retail prices without question.

⁷ Low wholesale prices imply low retail prices even if retail choice is not allowed. A state regulatory authority simply has to pass through the low wholesale price to retail electricity users in the form of a low retail price for electricity.

The next section contains a list of definitions that should be referred to when reading the remainder of this analysis. Subsequent sections of the paper summarize the salient characteristics of Network Access Service (NAS), the standard transmission service proposed in the SMD NOPR; describe the relationship of LMP to congestion management mechanisms (CMMs); and examine the implications of establishing FERC's proposed system of financial rights, which are CRRs designed primarily for use by wholesale customers.

II. Definitions

Available Transfer Capability⁸: A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. Available Transfer Capability is defined as the Total Transfer Capability, less the sum of existing transmission commitments (including transmission that is used for reliability purposes).

Congestion⁹: The state of the transmission system when a binding limit (constraint) on the system's transfer capability is reached that must be addressed.

Congestion Charges¹⁰: Charges relating to the (marginal) congestion component of energy purchases or transmission usage charges. These charges reflect the increased cost that result from dispatching the transmission system to respect transmission system constraints.

Congestion Revenue Deficit¹¹: In the day-ahead market, the absolute value of the difference between the hourly congestion charge collection and the hourly net congestion revenue owed to Congestion Revenue Rights holders when the difference is negative.

Congestion Revenue Right¹²: A property right held by any customer, not necessarily a transmission user that entitles and/or obligates the holder of the right to receive specified congestion revenues.

⁸ ABC Transmission Provider, page no.14.

⁹ ABC Transmission Provider, page no.15.

¹⁰ ABC Transmission Provider, page no.15.

¹¹ ABC Transmission Provider, page no.15.

¹² ABC Transmission Provider, page no.15.

Congestion Revenue Surplus¹³: In the day-head market, the difference between the hourly congestion charge collection and the hourly net congestion revenue owed to Congestion Revenue Rights holders when the difference is positive.

Flow-gate¹⁴: A transmission facility (such as a transmission line or a transformer or some other component of the electrical network) or group of facilities (e.g., an interface).

Flow-gate Right¹⁵: A Congestion Revenue Right specified by a portion of the total MW capacity over a particular transmission flow-gate in a specified direction. Flow-gate Rights entitle the holder to collect congestion revenue associated with the specified MW flow over the identified flow-gate in the specified direction

Boundary Interface¹⁶: Point(s) used to indicate point(s) of receipt and point(s) of delivery outside of the service area.

Interface¹⁷: A defined set of transmission facilities.

Marginal Congestion Component¹⁸: Component of locational marginal price and transmission usage charge reflecting the cost of dispatching the resources available to the Independent Transmission Provider such that transmission constraints are respected.

Network Access Charge¹⁹: A charge designed to recover the embedded costs of the Transmission System.

Obligation Right²⁰: A Congestion Revenue Right that requires the customer to receive the congestion revenues (either positive or negative).

¹³ ABC Transmission Provider, page no.15.

¹⁴ ABC Transmission Provider, page no.18.

¹⁵ ABC Transmission Provider, page no.18.

¹⁶ ABC Transmission Provider, page no.15.

¹⁷ ABC Transmission Provider, page no.19.

¹⁸ ABC Transmission Provider, page no.20.

¹⁹ ABC Transmission Provider, page no.14.

²⁰ ABC Transmission Provider, page no.22.

Option Right²¹: A Congestion Revenue Right that allows the customer to receive the positive congestion revenues without the obligation to pay congestion revenues when they are negative.

Receipt-Point-to-Delivery-Point Congestion Revenue Right Obligation²²: Congestion Revenue Rights that confer: (1) the right to collect revenue equal to the applicable marginal congestion component of the hourly transmission usage charge from the receipt point to the delivery point when the marginal congestion component is positive, and (2) the obligation to pay an amount to the Independent Transmission Provider equal to the absolute value of the applicable marginal congestion component of the hourly transmission usage charge when the marginal congestion component is negative.

Receipt-Point-to-Delivery-Point Congestion Revenue Right Option²³: Congestion Revenue Rights that confer to the holder the right to collect revenues equal to the applicable congestion charge component of the hourly transmission usage charge from the receipt point to the delivery point when the marginal congestion component is positive, but do not obligate the holder to pay the absolute value of the applicable marginal congestion component of the hourly transmission usage charge when the marginal congestion component is negative.

Security Constrained Dispatch²⁴: The determination of the dispatch that incorporates all transmission constraints necessary for reliability.

III. Description and Characteristics of Network Access Service

Network Access Service (NAS) is the new (universal) transmission service that FERC has proposed as the replacement for Point-to-Point firm and non-firm transmission services and Network Integrated Transmission Service. The purchase of NAS gives a transmission customer the right to transmit power between any points on the transmission network.²⁵ This right, however, is constrained by the requirement that the transmission transaction is feasible under a security-constrained dispatch.²⁶ Because NAS is provided

²¹ ABC Transmission Provider, page no.23.

²² ABC Transmission Provider, page no.24.

²³ ABC Transmission Provider, page no.24.

²⁴ ABC Transmission Provider, page no.24.

²⁵ Itself the transmission network is best described as a group of interconnected transmission systems over which it is not possible to route electric power over pre-specified transmission facilities.

²⁶ SMD NOPR, p.5.

within and between transmission systems NAS is an important feature of the “seamless” electric energy industry that FERC desires to establish.²⁷

III. A: Description of Network Access Service

NAS allows a transmission customer to access any combination of receipt and delivery points on the transmission network by paying all applicable congestion charges and transmission losses.²⁸ All transmission customers are required to pay the congestion charge because under the Standard Market Design no transmission customer by virtue of its status in the United States electricity industry is exempt from the payment of congestion charges. The Standard Market Design, however, does provide a vehicle for the forgiveness of congestion charges. This vehicle is the CRR, described and analyzed in subsequent sections of this analysis.

NAS is purchased in the day-ahead or real-time markets for transmission service. In order to complete a NAS purchase, a transmission customer has to provide the Independent Transmission Provider (ITP) with the desired combinations of receipt and delivery points at the time of purchase. Because NAS is purchased by all transmission customers in either the day-ahead or real-time markets for transmission services these customers have the opportunity to change their receipt and/or delivery points on a daily or hourly basis.²⁹

III. B.: Un-hedged Network Access Service

If NAS is purchased in the day-ahead market for transmission services, the transmission customer pays the cost of congestion, if any, and the cost of the transmission losses that are associated with the transmission transactions. If this day-ahead transmission customer also intends to take electric power off the transmission network at a delivery point, then this customer has to pay a network access charge that is set to recover the embedded fixed, sunk and maintenance costs of the transmission network.³⁰ Thus for

²⁷ FERC has concluded that currently the United States’ electric energy industry is not “seamless” because there exist conflicting state and federal rules governing the use of interstate transmission facilities. See SMD NOPR, p. 4.

²⁸ A receipt point is defined as a location on the transmission network where the electric energy transaction originates, and a delivery point is defined as the location on the transmission network where this electric energy transaction terminates. SMD NOPR, p. 80.

²⁹ SMD NOPR, p. 81.

³⁰ SMD NOPR, p. 82.

some transmission customers and in particular load-serving entities (LSEs), NAS has three component charges: a congestion charge, if any, a transmission loss charge, and a network access charge.³¹

When NAS is purchased in the real-time market for transmission services the transmission customer must pay the cost of congestion and the transmission losses that are associated with these transmission transactions. If the transmission customer also is a LSE, then the real-time price for NAS includes a network access charge. Thus, it is useful to think of the real-time price of NAS that includes a network access charge as the *pure un-hedged* price of physically feasible NAS. The real-time price of NAS that does not include a network access charge may be thought of as the “rock-bottom” *un-hedged* price of physically feasible NAS.

III.C: Price Uncertainty Associated with Network Access Service

Price uncertainty is necessarily a characteristic of NAS. The reason for this uncertainty is that the NAS price structure is un-hedged by FERC design. Recall that all transmission customers either must pay or are initially required to pay congestion charges along with the charges for transmission losses.³² If we assume that the cost of transmission losses and the network access charge for LSEs do not vary over time, then the source of the price uncertainty is the cost of congestion.³³

III. D.: Operation of the Independent Transmission Provider

The defining feature of NAS and also a core characteristic of the Standard Market Design is that all transmission transactions that are requested in the day-ahead transmission market must be physically feasible under a security-constrained dispatch.³⁴ However, FERC has not fully articulated the physical feasibility criterion in the discussion of the Standard Market Design. As a result, this criterion is open to different interpretations by different ITPs.

³¹ The most common LSEs in the United States are direct access customers that purchase electric power directly from a generation company and the regulated electricity distribution company subject to state regulatory jurisdiction.

³² SMD NOPR, p. 82.

³³ Of course, the cost of transmission losses will change over time. Hence, there will be two sources of price uncertainty with respect NAS in general.

³⁴ SMD NOPR, p. 80.

Some ITPs may adopt the PJM approach, which allows the ITP to substitute lower bid electric power in the day-ahead market for electric power for electric power committed pursuant to a bilateral transaction under any conditions.³⁵ Other ITPs may adopt the California approach, which does not allow the transmission provider to substitute spot-market electric power for electric power committed pursuant to a bilateral transaction unless honoring the bilateral contract violates transmission constraints.³⁶ Neither the California nor PJM approach is *per se* superior to the other.

The California approach is associated with the risk of a day-ahead schedule for electric power that is too costly relative to the “least-bid” day-ahead schedule that can be realized under the PJM approach. Alternatively, the PJM approach is associated with higher transaction costs relative to the California approach because of the settlement costs incurred when spot-market electric power is substituted for electric power committed pursuant to a bilateral trade.³⁷ Therefore, the partially articulated NAS under the Standard Market Design leaves unanswered an important question. Are the additional dispatch costs associated with the California approach greater than, less than or equal to the substitution-related transactions costs associated with the PJM approach to ITP operation?

The answer to this question does not depend on whether FERC or a state regulatory authority wants to ensure the integrity of a bilateral transaction, although the assurance of the integrity of bilateral transactions would seem a good thing. An affirmation of the integrity of bilateral transactions would suggest that an ITP should not be allowed to substitute electric power purchased in the spot markets (i.e. the day-ahead and real-time markets for electric power) when transmission constraints are not violated unless both counter-parties to the bilateral transaction agree to the substitution. However, this approach also increases the transaction costs that are associated with contracting for electric power. Whether the sum of the case-by-case, substitution-related transaction costs associated with this alternative form of operation by an ITP is greater than, less than, or equal to the automatic substitution-related transaction costs associated with the PJM approach remains an open question.

³⁵ The grant of this level of flexibility to an ITP ensures that the original dispatch of the day-ahead schedule will be a “least-bid” dispatch, which is the analog of a “least-cost” dispatch in an un-reformed electric-power industry. But, this level of flexibility also ensures that no bilateral transaction is a bilateral contract. Instead, each bilateral transaction between an electric-power supplier and buyer is a *bilateral trade* that can be improved upon by the ITP as a result of the ITP’s superior information relative to the counter-parties of the bilateral transaction.

³⁶ Per the California approach, all bilateral transactions between an electric-power supplier and buyer are bilateral contracts.

³⁷ These transaction costs are recorded under several names that include transmission congestion contracts and contracts for differences.

Thus far, we have examined the complexities associated with the physical feasibility criterion of the SMD when the day-ahead schedule for NAS does not violate transmission constraints. In other instances, the day-ahead schedule for NAS will violate transmission constraints. Is the substitution of higher bid, spot-market electric power for lower bid, spot-market electric power or electric power committed pursuant to a bilateral transaction the preferred course of ITP action? This question will be addressed in more detail in Section IV of this analysis. For the present, it is sufficient to briefly examine two possible courses of action.

When the day-ahead schedule for NAS violates transmission constraints an ITP could choose to re-dispatch the day-ahead schedule for electric power. That action would imply that some bids into the day-ahead market for electric power that were not included in the original day-ahead schedule for electric power are now included in the re-dispatched, day-ahead schedule for electric power. As a result, the nodal electric-power prices associated with the re-dispatch of the day-ahead schedule for NAS are different than the nodal electric-power prices associated the original dispatch of the day-ahead schedule for NAS.

New nodal electric-power prices mean new congestion charges and a new distribution of congestion charges. Both are the quid pro quo for meeting all of the day-ahead requests for NAS. However, new congestion charges and a new distribution of congestion charges may create new winners and losers among transmission customers.

Another possible course of action is to exercise transmission loading relief (TLR) procedures when the day-ahead schedule for NAS violates transmission constraints. In this case, an ITP physically curtails load (i.e. does not serve some electricity users) in order to prevent the violation of transmission constraints. Many interested parties believe that the exercise of TLR procedures should be a last resort to avoid blackout, and therefore, that TLR procedures are not appropriate for bringing the day-ahead schedule for NAS in line with the identified violations of transmission constraints.

III. E: Choices for Load-Serving Entities

NAS allows the LSEs to choose to serve their load with any available generation resource within the service area of the ITP in a manner consistent with Network Resource Interconnection Service.³⁸ NAS also allows LSEs to access any interface to import power from the service area of a neighboring ITP in a manner consistent with Network Resource Interconnection Service.³⁹ Furthermore, NAS provides LSEs with the option of

³⁸ SMD NOPR, p. 79.

³⁹ Network Resource Interconnection Service requires that sufficient upgrades be built so that interconnecting generators can serve load as a network resource as defined by the existing *pro forma* tariff. SMD NOPR, p. 79.

delegating the control of their generation facilities and other load-serving resources to the ITP for the purposes of integrating, dispatching and regulating these network resources in the course of meeting the LSEs' loads.⁴⁰ Finally, LSEs can use NAS for through-and-out service.⁴¹

IV. Congestion Management

What does it mean to have a sufficient in-service investment in electric power infrastructure?⁴² It could mean that congestion never exists anywhere in the transmission network under normal operating conditions. It alternatively could mean that there is an optimal amount of congestion everywhere in the transmission network. The economic policy choice between these two alternatives is not trivial. Millions of dollars of infrastructure investment are at stake. FERC's policy seeks to manage congestion, not to eliminate it.

IV. A: Foundation of the Congestion Management Portfolio

The means of congestion management are explicitly chosen and carefully integrated into FERC's Standard Market Design. Because of the physics of the flow of electric power (especially the inability to route electric power like a telephone call) FERC has prudently selected several means to manage transmission congestion. The foundation for FERC's congestion management portfolio is the optimization, that is, cost minimization, of the dispatch of the available generation assets subject to transmission network security constraints—i.e. least-cost dispatch.

The method of least-cost dispatch was used extensively prior to the reform of the United States electric power industry. Each vertically integrated utility, in the course of preparing to meet its expected electric-power load, would use the marginal variable costs of its available generation facilities as the criteria for dispatching generation assets to meet the electric load in a reliable manner.⁴³ All fixed costs of generation assets were

⁴⁰ SMD NOPR, p. 79.

⁴¹ SMD NOPR, p. 79.

⁴² Although as meaningless as most tautologies are it still is instructive to say that the sufficiency of the volume of CRRs is totally dependent on the sufficiency of the total investment in electric power infrastructure, which in terms of physical assets includes the actual in-service investment in transmission and generation facilities.

⁴³ Marginal variable cost is sometimes called "marginal running cost." The most practical way to interpret either of these economic cost concepts is the generation facility's marginal fuel cost because fuel cost is such a large component of variable costs of producing electric power.

treated as “sunk” costs, and as “sunk” costs these fixed costs did not affect an optimal dispatch of generation facilities.⁴⁴ In the course of the reform of the United States electric-power industry least-cost dispatch has in part been based on bids to supply and buy electric power in spot markets.

The physical dispatch principles of the two dispatch criteria are the same; however, the measures of economic value are different. Prior to reform the measure of economic value used to determine the optimal dispatch of available generation facilities was cost. Subsequent to the reform bids are the measure of economic value that drives the optimal dispatch of generation. If the electric-power industry were perfectly (or even workably) competitive, then the differences between the economic concepts of cost and bids would be so small as to go unnoticed.

However, the differences between bids and cost are noticeable and important in the reformed United States electric-power industry. It has become apparent that non-negligible horizontal and vertical market power continue to exist in the local and regional electricity markets in the United States. As a result, there is a non-cost-based “mark-up” in the bids submitted into the spot markets for electric power as compared to the cost of electric power. This is the standard and widely accepted definition of market power, and its presence impairs the effectiveness of FERC’s congestion optimization policy.

IV. B: The Foundation of the Congestion Management Portfolio

Locational marginal pricing (LMP) is the foundation of FERC’s congestion management portfolio. LMP simply means: “perform the optimal dispatch of the available generation facilities (based on “bids”) that respects the transmission security constraints (thereby ensuring electricity reliability) and then extract the shadow electric energy nodal prices at each node in the transmission network.” A shadow nodal electric energy price is defined as the nodal marginal (electric power) bid for any node within the transmission network. A nodal marginal (electric power) bid is defined as the supply- price bid for the last generation facility dispatched at the controlling node. Finally, the controlling node is defined as any node in the transmission network that prescribes the shadow nodal electric energy prices for one or more nodes in the transmission network.

When the optimal dispatch can be achieved without creating congestion anywhere in the transmission network, all of the shadow nodal electric energy prices are equal, and as a result the VOC (i.e. the value of congestion) for any pair of receipt and delivery points within the transmission network is zero. If, however, generation facilities cannot be optimally dispatched without experiencing congestion on the transmission network, then the VOC for a matched pair of receipt point and delivery points is determined by

⁴⁴ This economic principle, often questioned by a practical businessperson, is especially relevant for vertically integrated utilities operating in the pre-reform environment because these utilities most often were subject to traditional rate base/ rate of return regulation.

subtracting the shadow nodal electric energy price at the receipt point from the shadow nodal electric energy price at the delivery point and then taking the absolute value of this resulting difference.

The VOC for a matched pair of receipt and delivery points is the absolute value of the arithmetic difference of the (shadow) nodal prices for this pair, i.e. the difference between nodal prices. Everyone purchasing NAS is obligated to pay the VOC to the ITP.⁴⁵ The purpose achieved by calculating the VOC is to determine the absence or presence of congestion with respect to any pair of receipt and delivery points contained within the transmission network. Hence, LMP also can be thought of as a congestion indication vehicle (CIV).

To sum up: LMP identifies congested pairs of receipt and delivery points within a transmission network by permitting the discovery of the VOC; that is, by permitting the discovery of a “price” of congestion. Clearly, a VOC is not necessarily the cost of congestion. A VOC would be the cost of congestion, if the electric-power market associated with the ITP were either perfectly or workably competitive in the economist’s sense of the term. In all other market environments the VOC is not equal to the cost of congestion. More than likely, a VOC associated with a market that is non-competitive will be higher than the cost of congestion for that market.

IV. C: Transmission Loading Relief

Transmission loading relief (TLR) is a CMM that FERC has deemed a necessary aspect of the Standard Market Design. TLR is activated when the transmission system operator seeks to avert a contingency that might lead to blackouts. The application of a generic TLR procedure causes a reduction in the amount of power that is injected into the receipt point and ejected at the delivery point. As a result, the application of a TLR procedure causes the diminishment in the amount of electric power flowing over the transmission network. Inevitably then, the application of a TLR procedure results in either some electricity customers not being served or the injection of electric power into the transmission network at other receipt points.

IV. D: Re-dispatch of the Day-Ahead Schedule for NAS

⁴⁵ “The Independent Transmission Provider must honor all valid transmission requests where there is sufficient capability, i.e. when there is no transmission congestion.” SMD NOPR, p.112. The purchase of NAS—the new (universal) transmission service—ensures that any transmission customer’s request for day-ahead transmission service will be honored for any combination of receipt and delivery points as long as it is physically feasible for the ITP to provide the requested transmission service and the requesting transmission customer is willing to pay the day-ahead congestion charges.

Re-dispatch of the original day-ahead schedule for NAS is another CMM. In order to understand how this CMM works, it is instructive to develop the full meaning of a “least-bid” dispatch of electric power. This type of generation-asset dispatch begins with the determination of the available generation facilities. Let’s define available generation facilities as the generation facilities that are “in-service.” Let’s define “in-service” to mean that the associated generation facilities are not unavailable because of scheduled maintenance or a forced outage, that is, because of a mechanical breakdown of some sort. There is no guarantee that a generation facility that is “in-service” will be dispatched by the ITP because the bid associated with this generation facility may be too high in relation to other bids.

The second step in this type of generation-asset dispatch is to determine what percentage of the “in-service” generation facilities is committed to bilateral transactions and hence unavailable for supply into the day-ahead and real-time spot markets. Once this percentage has been determined the third step is to subtract it from the “in-service” generation normalized at 100 percent leaving the percent of “in-service” generation facilities that is available to supply the spot markets. It is these generation facilities that in a very real sense support the electric supply bids into the spot markets.

Electric supply bidders submit bids to supply the day-ahead electric power and the real-time electric power markets. There is a definite sequence to these bids. First, the bids to supply the day-ahead electric power market are submitted to the ITP along with the bids to buy electric power in the day-ahead market. Second, the bids to buy and sell in the real-time market are submitted for consideration. Under the Standard Market Design there are no guarantees that electric power will be needed to supply the real-time market. Hence, in principle, there is a speculative risk associated with not bidding “in-service” generation facilities into the day-ahead market and waiting for the real-time market. A real-time may not materialize. Whereas in the context of the Standard Market Design the day-ahead market for generation facilities always materializes.

The ITP establishes the day-ahead schedule for the delivery of electric power with knowledge of the “in-service” generation facilities that are committed to bilateral transactions, and of the “in-service” generation facilities that are available to supply the day-ahead market for electric power. First, the ITP has the counter-parties to the bilateral contracts submit their receipt and delivery points for the next day and designate how the supply of electric power to the ITP will be accomplished. Second, the ITP opens the day-ahead electric-power market to the bidders. Third, the ITP clears this day-ahead market, which results in a day-ahead schedule for generation facilities sold into the day-ahead electric-power market. Fourth, the ITP combines the generation facilities committed to bilateral transactions with the generation facilities accepted to supply the day-ahead electric-power market. This combination of “in-service” generation facilities is the day-ahead schedule of electric-power supply.

It is useful to note that the ITP has not yet dispatched these “in-service” generation facilities. All the ITP knows at this time is receipt and delivery points, the amount of electric power that buyers and sellers want to flow between these receipt and delivery

points, and the sources of the electric power that are to be used to meet the commitments made by buyers and sellers. Prior to dispatch, neither the ITP nor anyone else yet knows whether it is physically feasible to dispatch the “in-service” generation facilities in the manner desired by the buyers and sellers.

Although not totally clear on the subject the SMD NOPR suggests that the ITP is to explore every avenue for fulfilling the desires of buyers and sellers and is not to exercise its own judgment under any circumstances when it comes to a bid-based substitution of non-designated “in-service” generation facilities for customer-designated “in-service” generation facilities. Let’s assume that only customer-designated generation facilities are associated with the day-ahead schedule for bilateral transactions. This means that the ITP must make every effort to dispatch the generation facilities that the counter-parties want to be dispatched. In order to simplify matters further let’s assume that only customer-designated “in-service” generation facilities have been bid into the day-ahead electric-power market; that is, there were not any supply bids into the day-ahead electric-power market that did not designate receipt and delivery points and the generation facilities that will be used to supply the electric power. But, still it is apparent that the ITP has not “dispatched” anything.

At last the ITP is ready to dispatch the pre-identified “in-service” generation facilities. The dispatch is potentially a two-part exercise. In the first part, which always occurs, the ITP determines the unconstrained dispatch of the available generation facilities that minimizes costs. The ITP then inspects this preliminary day-ahead optimal dispatch for violations of network security constraints. If no violations of network security constraints are found, the day-ahead optimal generation dispatch has been identified.

If the inspection of the unconstrained dispatch revealed violations of the network security constraints, congestion is present. Furthermore, discovered violations of network security constraints mean that the day-ahead schedule is not physically feasible. The ITP must “re-dispatch” the available generation facilities if the ITP does not want to exercise TLR procedures.

In the context of our example, the re-dispatch of the available generation facilities means the substitution of non-designated generation facilities for customer-designated generation facilities in order to remove the violations of the network security constraints.⁴⁶ The procedure followed by the ITP is to inspect its list of available generation facilities that have not been dispatched (presumably because the associated supply bids were too high) for the purpose of determining whether or not it can relieve the congestion discovered in the day-ahead schedule by the exchange of lower bid for

⁴⁶ FERC notes that an ITP is not inclined to conduct a re-dispatch of the day-ahead schedule when the receivables associated with the day-ahead schedule are fixed at the level determined by the original dispatch of the “in-service” generation facilities.

higher bid generation.⁴⁷ If all or some percentage of the congestion can be relieved by the exchange of generation facilities, then the ITP re-dispatches the available “in-service” generation facilities. When the re-dispatch removes all of the congestion the ITP issues a new day-ahead schedule for the electric-power market. If the re-dispatch does not remove all of the congestion, then the ITP issues a warning that it may not be able to meet the load on the following day, which is a signal that the ITP may be forced to exercise TLR procedures on the following day. Thus, re-dispatch is the second CMM that is contained in the Standard Market Design.

IV. D. 1: Re-dispatch with Full Compensation to the ITP

Re-dispatch *with full compensation to the ITP* raises issues about higher generation costs paid by end users that could result from a transmission provider creating a potential to sell more transmission service in the real-time market. Consider the following possibility. The original dispatch does not violate the network security constraints, but the ITP suspects that it can increase the available transfer capability for the real-time market by re-dispatching the day-ahead schedule anyway. By definition, the re-dispatch exchanges higher bid generation facilities for lower bid generation facilities at crucial nodes within the transmission network. Consequently, the amount of money that has to be paid to the bidders is increased. If these additional revenues are collected from transmission customers, then the price of bundled and unbundled retail electricity service will increase. State public utility commissions will most likely suffer the brunt of the criticism that will be associated with the higher retail electricity prices. This hypothetical example reveals the compelling need for ITP activities to be monitored by independent observers.

Although FERC appears comfortable with its tentative decision to fully compensate an ITP for a reliability enhancing re-dispatch, there are other revenue-compensation problems associated with re-dispatch for reliability purposes. The fact that re-dispatch may “back-off” some generation from the original day-ahead schedule raises this group of problems.

Suppose that a re-dispatch for reliability purposes does not involve counter-flows. It follows that some tentatively listed electric-power suppliers on the original day-ahead schedule will not be listed on the re-dispatched day-ahead schedule.⁴⁸ As a result, a question is raised as to the obligation of an ITP to electric-power suppliers that are listed on the original day-ahead schedule and not listed on the re-dispatched day-ahead schedule. Should the “backed-off” electric-power suppliers be compensated for the

⁴⁷ At this stage of the procedure, the ITP hopes to be able to relieve all of the congestion by the exchange of generation facilities.

⁴⁸ If the re-dispatch to relieve congestion does not make use of counter-flows of electric power, then physics of electric-power flows ensure some generation facilities associated with the original day-ahead schedule will not be dispatched on the next day.

revenue that they will not receive because their electric-power supplies no longer are needed to meet the next day's load? The SMD NOPR does not address this question, although it does address the question of where the ITP will obtain the revenues to fully compensate the new electric-power suppliers that are listed in the re-dispatched day-ahead schedule.

There is public policy implications of both questions establish which suggest re-dispatch for reliability purposes is a two-sided coin when it comes to the compensation of electric-power suppliers. If the electric-power suppliers "backed-off" are not fully compensated for the effects of forces beyond their control, then they lose revenue through no fault of their own with the result that they become less willing to bid in the day-ahead electric-power market or to enter into bilateral trades or contracts.⁴⁹ If the electric-power suppliers added to the re-dispatched day-ahead schedule are not fully compensated for the electric-power supplies that they provide to the ITP, then these suppliers will not make electric power available to the ITP. These implications suggest the need for a two-sided compensation procedure, where the ITP is able to collect the additional revenue required to fully compensate the electric-power suppliers that are added to the re-dispatched day-ahead schedule, and the "backed-off" generator is compensated appropriately for lost fixed cost recovery. Unfortunately, a two-sided compensation procedure makes it less likely that re-dispatch will be used as a congestion management response because of the increased transaction costs.

IV. E: Locational Marginal Pricing as a Trigger for Transmission-customer-initiated Cancellation of NAS

Neither re-dispatch nor TLR procedures requires LMP as a trigger for its exercise. LMP provides transmission customers with a measure of flexibility of use after they purchase NAS, either under contract or in the day-ahead market for NAS. In fact, LMP provides the economic signal that alerts transmission customers to potential economic benefits of exercising their measure of flexibility of use.

Recall that LMP is used to determine the day-ahead VOC for a receipt-point-to-delivery point path by generating a set of nodal electric energy prices for each hour of the day-ahead schedule. All of the nodal prices are the same for those hours of the day when there is no congestion. Conversely, there are differences among the nodal prices for those hours of the day when there is congestion. If a transmission customer is

⁴⁹ The Standard Market Design allows the "backed-off" electric-power suppliers to retain the right to congestion rents on the load-relieved receipt point to delivery point paths, if and only if the "backed-off" electric-power suppliers hold CRRs for these paths. However, the values of these rights may be reduced to zero, which does occur when the reliability enhancing re-dispatch totally relieves the congestion on these paths. Because these paths are no longer congested the CRRs are worthless. Therefore, it follows that holding CRRs does not provide protection against revenue loss accruing to "backed-off" electric-power suppliers. CRRs are examined in detail in the next section of this paper.

transmitting electric energy between congested receipt and delivery points, then the nodal price at the receipt point is less than the nodal price at the delivery point. The positive number that is obtained when the nodal price at the receipt point of the congested combination is subtracted from the nodal price at the delivery point is the VOC for this combination of receipt and delivery points in the day-ahead market for NAS. As a result, transmission customers have access to an economic signal that they can use to automatically alert the ITP that they want to cancel some or all of their NAS order without prejudice.⁵⁰ Transmission-customer-initiated cancellation of NAS that is activated because the associated day-ahead VOC is too high for these transmission customers to pay is the third CMM that is proposed in the SMD NOPR.⁵¹

V. Congestion Revenue Rights

A system of financial rights—CRRs in the Standard Market Design—gives transmission customers the ability to protect themselves against congestion costs.⁵² The Standard Market Design allows an ITP to offer several types of CRRs to transmission customers.⁵³ FERC proposes that one type of CRR has to be made available immediately and that three other types of CRRs should be made available upon customer request when it is technically feasible to do so.⁵⁴

The immediately mandated type of CRR is the receipt-point-to-delivery-point congestion revenue right obligation.⁵⁵ The second type of CRR is the receipt-point-to-delivery point

⁵⁰ Under the Standard Market Design market participants have the ability to signal whether they are willing to buy their way through transmission constraints. SMD NOPR, p. 119.

⁵¹ The cancellation of NAS because the transmission customer is unwilling to pay the VOC implies the reduction of electric-power flows on a congested receipt point to delivery point path, which is an outcome can be classified as a price-based, customer-initiated congestion management.

⁵² SMD NOPR, p. 132.

⁵³ SMD NOPR, p. 124. p. 133.

⁵⁴ SMD NOPR, p. 133. The three other types of rights do not have to be offered initially because there is not any experience with them. SMD NOPR, p. 139. “However, upon the request of market participants the Independent Transmission Provider would be required to offer receipt point to delivery point options and flow-gate rights as soon as technically feasible.” SMD NOPR, p. 140.

⁵⁵ SMD NOPR, p. 134, p.139.

congestion revenue right option.⁵⁶ The third type is the flow-gate congestion revenue right obligation.⁵⁷ The fourth type is the flow-gate congestion revenue right option.⁵⁸ FERC believes that several types of CRRs will make the transmission network more flexible and better able to adapt to the needs of specific transmission customers.⁵⁹ FERC suggests that different types of CRRs may be more valuable in different parts of the United States as a result of variation in the location of transmission assets and variation in the types of available generation capacity.⁶⁰ Variations in the structure of CRRs beyond obligations and options and flow-gate and receipt-point-to-delivery-point congestion revenue rights will create additional transaction costs for market participants that do business in several regions of the United States. Fortunately, most LSEs, in particular the regulated electricity distribution companies, are not among this class of market participants.

FERC seeks direction with respect to the length of time that LSEs, other market participants, and other transmission customers can hold a CRR. In principle, a CRR can be in force and held by transmission customers and others for a very short period of time or a somewhat long period of time. Currently, FERC is considering the issuance of CRRs that are in force for a week, a month, a number of months, and a year.⁶¹ However, FERC seeks comment on whether an ITP should be required to offer a multi-year CRR such as a five-year CRR to transmission customers and others.⁶²

V. A: Classes of Congestion Revenue Rights

Congestion Revenue Rights fall into two classes as far as the SMD NOPR is concerned. The more familiar class—an extension of the old contract path for wheeling purposes—is the receipt-point-to-delivery-point congestion revenue right. This financial right to congestion revenues is defined between two nodes on the same transmission network. It

⁵⁶ SMD NOPR, p. 134.

⁵⁷ SMD NOPR, p. 134.

⁵⁸ SMD NOPR, p. 134.

⁵⁹ SMD NOPR, p. 134.

⁶⁰ SMD NOPR, p. 134. FERC notes in SMD NOPR that the Northwest segment of the United States worries that receipt-point-to-delivery-point CRRs may require a supplemental CRR that recognizes the contingent nature of some generation supply resources. SMD NOPR, p. 124.

⁶¹ SMD NOPR, p. 133.

⁶² SMD NOPR, p. 140.

is not easily extendable to apply to a receipt point on one transmission network and a delivery point on another transmission network with imports and exports. The less familiar class is the flow-gate right that is defined by an identifiable group of transmission facilities instead of receipt points and delivery points. However, a flow-gate right as defined by the SMD NOPR is a financial right rather than a physical transmission right. Physical transmission rights are not considered explicitly in the SMD NOPR.⁶³

V. A. 1: Receipt-Point-to-Delivery-Point Congestion Revenue Rights

A receipt-point-to-delivery-point CCR is a derivative of the basic receipt-point-to-delivery-point right that is appended to NAS. As noted previously, this basic right entitles transmission customers that purchase transmission service in the day-ahead market to schedule and receive NAS between any pair of receipt and delivery points within the transmission network as long as it is physically feasible to meet the demands of the day-ahead schedule. In order to exercise this basic right, transmission customers have to specify a receipt point such as a generator node, an aggregation of generator nodes, an interface, a trading hub, or any other collection of nodes and a delivery point such as a delivery node, an aggregation of delivery nodes, an interface, or a trading hub. Additionally, the amount of electric power measured in MW s to be transmitted for a specific period of time such as an hour between the pertinent receipt and delivery points has to be specified by the transmission customers.

It is not likely that the transmission network never will be subject to the effects of congested transmission lines. As such, an ITP will need to deal with transmission congestion either through TLR procedures, the re-dispatch of the day-ahead electric power schedule, or via the coordination of demand-response programs made available to transmission customers. Pursuant to such programs transmission customers are obligated to reduce electric-power load upon the request of the ITP. Assuming the customer is not an interruptible load customer, it would be provided monetary compensation if the

⁶³ It is tempting to conclude that physical transmission rights are redundant in the context of NAS. Recall that NAS assures that all requests for transmission service will be fulfilled as long as transmission constraints are not violated. Hence, why would there be a need for physical transmission rights, which ensure that a particular transmission customer will have access to the specific transmission facilities that it requires to meet the commitments contains in its bilateral contract with a counter-party. However, there is a significant difference between a physical transmission right and NAS. A physical transmission right is purchased to gain complete assurance that even a violation of a transmission constraint in the context of the original day-ahead schedule for transmission service will not prevent the holder of physical transmission right from meeting its commitments under a bilateral contract. In short, the holder of a physical transmission right is loaded first on the designated transmission facilities and is never bumped off these facilities for any reason.

eliminated MW-load allowed the ITP not to exercise TLR procedures.⁶⁴ The money would be collected by the ITP from the remaining “on-line” transmission customers who have decided, by their decisions to remain ‘on-line’. to buy-through the congestion on the transmission network.

The presence of direct and indirect CMMs in the Standard Market Design shows that FERC expects a transmission network to violate transmission constraints at least some of the time.⁶⁵ For a variety of reasons, some transmission customers may not want to be subject to the effects of CMMs. More than likely, at any moment in time, there will be a subset of transmission customers willing to buy-through transmission congestion at nearly any price.

A standard price hedge for congestion costs money. Suppose that a transmission customer purchases an option on a financial instrument that would exempt this transmission provider from the payment of congestion charges for a specified period of time. This transmission customer would have to pay something to someone in order to get this price hedge, even though this transmission customer never exercises the financial option. An explicit payment to manage congestion on the transmission network is a novel market-design element for the United States electricity industry. Accordingly there will be subsets of transmission customers that truly believe that members of their subset should be exempted either permanently or temporarily from the payment of congestion charges.

FERC has decided that existing transmission customers paying the network-access-charge component of NAS are entitled to be exempt from congestion charges in the day-ahead market for transmission service. FERC also has decided to use the CRR to provide these transmission customers with their [short-term] exemption from the payment of congestion charges. Because NAS is a receipt-point-to-delivery-point transmission service the CRR associated with NAS is the receipt-point-to-delivery-point CRR. This CRR entitles its holder to the day-ahead congestion revenues that are associated with the receipt and delivery points.

⁶⁴ An interruptible load customer agrees to be cut off from the transmission network in order to avoid a transmission contingency. In return, this customer pays a lower price for delivered electric power than does another customer that is not interruptible. Load interruption is just one form of demand response program. Another form is the pre-specification of the maximum congestion charge that a transmission customer is willing to pay to complete the delivery of electric power to the delivery point on the transmission network.

⁶⁵ Re-dispatch of the day-ahead electric-power schedule and the exercise of TLR procedures are direct CMMs. Pre-specification of the maximum congestion charge that an individual transmission customer is willing to pay and interruptible load service are examples of indirect CMMs.

Recall that [expected] congestion revenues as a result of the day-ahead schedule for NAS are estimated on the basis of the [expected] nodal prices at receipt and delivering points that are calculated on the basis of the day-ahead schedule for electric power. Under LMP the absolute difference of the nodal prices between receipt and delivery points is the congestion rent that is associated with a matched pair of receipt and delivery points. When collected by the ITP this congestion rent is the congestion revenues that the holder of the relevant CRR is entitled to receive from the ITP.

Although the amount of a congestion rent is determined on the basis of an absolute value calculation, the holder of the relevant CRR does not always receive the congestion rent in the amount calculated on an absolute-value basis. FERC asserts that the holder of a CRR always receives the congestion rent,⁶⁶ but a congestion rent when *received* by the holder of the CRR can be either negative or positive.⁶⁷ When the holder of a CRR receives a negative congestion rent this transmission customer has to make a payment *to* the ITP. Conversely, a transmission customer holding a CRR receives a payment *from* the ITP when the congestion rent is positive. *Hence, the proposed CRR does not provide its holder with complete protection from the payment of congestion rent to the ITP.*

On the basis of the preceding discussion it should be apparent that receipt-point-to-delivery-point CRR is direction-specific. Clearly, positive and negative congestion rents would not be possible if the type of CRR was not direction-specific.⁶⁸ The direction of this type of CRR is determined by the direction of the flow of electric power that is associated with this type of CRR. And the direction of the flow of electric power is from the receipt point to the delivery point and never from the delivery point to the receipt point regardless of the actual path that is taken to reach the delivery point.⁶⁹ *As a result, a change in the pattern of the flow of electric power on the transmission network may cause a regulated electricity distribution company to become a net payer of congestion rents rather than a net receiver of congestion credits to offset current congestion charges.*

Another entitlement is associated with receipt-point-to-delivery-point CRRs. When the quantity demanded of transmission service cannot be met with the available transfer capability a holder of a receipt-point-to-delivery-point CRR will receive priority over

⁶⁶ SMD NOPR, p. 80, p. 82, fn. 90.

⁶⁷ SMD NOPR, p. 135, fn. 135, pp. 136-137.

⁶⁸ FERC argues in the SMD NOPR that the holder of a relevant receipt-point-to-delivery-point CRR can schedule transmission service for a specified amount of power in the day-ahead market from the receipt point to the delivery point without paying any net charges for congestion. SMD NOPR, p.1 36. Elsewhere FERC states that the holder of receipt-point-to-delivery-point CRR must make a payment to the ITP when the congestion rent is negative.

⁶⁹ SMD NOPR, p. 135.

other market participants in the scheduling of NAS between the receipt point and the delivery points designated in their CRR.⁷⁰ This feature of the SMD NOPR is a good thing as far as regulated electricity distribution companies are concerned because initially they would be assured of scheduling priority in the day-ahead market for transmission service. *However, there are passages within the SMD NOPR that suggest that this scheduling priority will erode over time.*

FERC hopes to be able to offer receipt-point-to-delivery-point CRRs as either an obligation or an option.⁷¹ The difference between obligation and option is important when the congestion is in the *opposite* direction of the associated CRR. In this case, the holder of CRR obligation must pay the amount of the congestion rent to the ITP. For example a payment for “negative congestion” could be received by an ITP from a regulated electricity distribution company.⁷² The requirements on the holder of receipt-point-to-delivery-point CRR option are another matter. A CRR-option holder would not have to make a payment to compensate an ITP for “negative congestion” because the CRR option, which is in the *opposite direction* of the congestion, would not be exercised. As a result, the availability of this type of option would be extremely important to regulated electricity distribution companies when there exist strong expectations that the pattern of the use of transmission network will change rapidly and frequently. But, it cannot be forgotten that the purchase of options involves a real monetary cost to the option buyer. *It is possible that the availability of receipt-point-to-delivery-point CRR options could increase the price of retail electricity when electricity distribution companies determined to avoid negative congestion rents purchase them.*

Lastly, FERC notes that receipt-point-to-delivery-point CRRs do have some problems beyond the negative congestion rents. While unlikely in the near term, a LSE eventually may choose to serve its load from a portfolio of generation facilities that is changed frequently. In this instance, long-term receipt-point-to-delivery-point CRR obligations would not be too valuable because the CRR holder may have to resell them in an illiquid secondary market. A risk-minimizing regulated electricity distribution company—a LSE whose welfare is exceedingly important to political and regulatory authorities—will be prone to favor long-term CRRs. *Consequently, policy makers may need to closely monitor and analyze the liquidity of the secondary markets for CRRs. The secondary market for long-term CRRs is apt to be illiquid because liquidity for this market requires buyers with the same receipt and delivery points as sellers.*

V.A.2: Flow-gate Congestion Revenue Rights

⁷⁰ SMD NOPR, p. 135.

⁷¹ SMD NOPR, p. 136.

⁷² SMD NOPR, pp. 136-137.

A flow-gate is defined in the SMD NOPR in terms of a particular transmission facility or group of facilities. Interfaces between ITPs comprise transmission facilities or a group of transmission facilities of particular importance to regulatory authorities. The transmission transfer capability of an interface is a limiting factor on the amount of electric power that can be imported into and exported from the service area of an ITP. From this perspective, the major operational purpose achieved by identifying a flow-gate is an increased precision in the estimate of the level of congestion between ITPs. In consequence, electric-power suppliers will be better positioned to estimate the physical feasibility of different export and import patterns.

A flow-gate congestion revenue right specifies a portion of the transmission capability over an identified flow-gate (i.e. a particular transmission facility or group of transmission facilities) in a specified direction that is the property of the holder of flow-gate CRR.⁷³ FERC argues that this right entitles its holder to the day-ahead congestion revenues that are associated with power flows over the flow-gate in the specified direction.⁷⁴ Because a flow-gate CRR may be tied to only a portion of the transmission capability that is associated with the flow-gate under normal operating conditions the holder of the flow-gate CRR is entitled to only the same proportion of the congestion revenues that are associated with this flow-gate.

FERC argues that the holder of a flow-gate CRR never is required to make congestion payments.⁷⁵ This characteristic of a flow-gate CRR is easily explained. Consider the situation of export/import interface with the flowing power flows between ITP service areas A and B. Electric power is exported from service area A to B and from service area B to A. Thus, service areas A and B both receive electric-power imports and send electric-power exports. Obviously, there can be congestion over this flow-gate in only one direction at a time; that is, the congestion over this flow-gate is either from service area A to B or from service area B to A. Suppose that the transmission congestion exists from service area A to B. The holder of the flow-gate CRR from service area A to B is completely protected against congestion charges while the holder of the flow-gate CRR from service area B to A does not experience any congestion.

If it is possible to easily and quickly identify flow-gates on a near real-time basis, then flow-gate CRRs will facilitate the efficient operation of the Standard Market Design. The quick and easy identification of flow-gate will improve the operational efficiency between and among ITPs; that is, it will be possible to import and export electric power more easily.⁷⁶ Furthermore, FERC is correct to list as an advantage of quickly and easily

⁷³ SMD NOPR, p. 137.

⁷⁴ SMD NOPR, pp. 137-138.

⁷⁵ SMD NOPR, p. 138.

⁷⁶ Operational efficiency in the context of ITP inter-operation is the “middle child” of the seamless transmission network that has been described by FERC in the SMD NOPR.

identifiable flow-gates that transactions costs in the transmission sector of the United States electricity industry can be lowered because transmission customers can focus their energies and acquire rights on the perennially congested flow-gates.

V. B: FERC Preferences for the Distribution of Receipt-Point-to-Delivery-Point Congestion Revenue Rights

Notwithstanding whether or not some subsets of the existing transmission customers are entitled to receipt-point-to-delivery-point CRRs, the SMD NOPR makes it clear that FERC prefers an auction of these CRRs to an assignment of these CRRs.⁷⁷ Presumably, FERC believes that an auction will more closely match the time-limited ownership of CRR obligations with LSEs and other market participants that value them most highly.

By participating in the auction, a LSE or other market participant reveals its belief that paying for a CRR is better than paying the congestion charge or running the risk of not receiving electric power at its delivery point. Participation in the auction is evidence that CRRs are incentive-compatible, because the alternative leaves the LSE without protection against an uncertain congestion charge. When a LSE or other market participant wins an auction for no other reason than minimizing the transmission costs, this transmission customer has demonstrated that the purchased CRRs are at least as valuable as the price that the transmission customer paid for them. Hence, the LSE or other market participant is behaving in an individually rational manner.

FERC also has a preference for the use of the auction proceeds. FERC wants to distribute the proceeds to existing transmission customers such as regulated electricity distribution companies in a manner that holds them harmless financially. The creation of flow-gate and receipt-point-to-delivery-point CRRs is intended to meet this criterion.

It is not necessarily the case, however, that existing transmission customers will inevitably be held financially harmless with CRR-auction proceeds. Let's consider a possible behavior of a regulated electricity distribution company. Suppose this company decides to participate in the auction, and assume that this company is able to purchase all of the CRRs that it desires. Then it follows unambiguously that the auction has held this customer financially harmless. The regulated electricity distribution company would pay the ITP for the CRRs, and the ITP would reimburse the same amount to the electricity distribution company.

Another possibility is that the regulated electricity distribution company participates in the auction, but the company is not able to obtain all of the CRRs that it desires. In this case, the electricity distribution company is unprotected against congestion charges with respect to some of its receipt-point-to-delivery-point paths. In theory, the company could decide not to receive electric power at the delivery points where it does not have CRRs when the congestion charges are greater than the amounts that this company was willing

⁷⁷ SMD NOPR, p. 11.

to pay for the CRRs. *However, by taking that course of action, the regulated electric distribution company could incur a non-measurable cost, the cost of not being able to deliver electricity to some of its customers.*

Furthermore, a regulated electricity distribution company that does not win all of its desired CRRs at auction is not protected against an inability to schedule NAS in the day-ahead market for transmission service when the quantity of electric power scheduled to be transmitted is greater than the total transfer capability of the transmission network. Under these circumstances, this company would be unable to schedule NAS over the affected receipt-point-to-delivery-point paths. *As a result of the reduced availability of electricity to its customers, the regulated electricity distribution company would incur as non-measurable cost.*

FERC prefers multi-year CRRs because long-term power contracts play an important reliability-enhancing role in its Standard Market Design. However, FERC also notes that it could be very difficult to place a value on multi-year CRRs because of changing load patterns.⁷⁸ For this reason, multi-year CRRs may never be offered at auction by an ITP. Such an outcome could reduce the effectiveness of the Standard Market Design although the potential reduction in effectiveness might not be too significant if the market for CRRs for one year is liquid.

Under those circumstances, the ITP would conduct an auction for yearly CRR obligations and administer a market for yearly CRR options. The year associated with the CRR option would be the year immediately following the year of the CRR obligations. Several methodologies are available to value yearly options, which means that it will not be too difficult to place values on put and call options for CRRs.⁷⁹ A forward market for yearly CRRs could develop when call and put options for yearly CRRs are in place. *The presence of these financial instruments along with a liquid market for yearly CRR obligations can lower the price of protecting against uncertain congestion charges.*

V. C: Initial Distribution of Congestion Revenue Rights

Although FERC has a preference for CRR auctions it has proposed a four-year transition period leading to such an auction. During this period, an ITP can use some other method to apportion CRRs in a manner that is as neutral as possible for existing transmission customers.⁸⁰ FERC proposes in the SMD NOPR that the initial distribution of CRRs to selected subsets of transmission customers will be accomplished through compliance

⁷⁸ SMD NOPR, p. 140.

⁷⁹ A LSE such as a regulated electricity distribution company would place the call option, and the ITP would place the put option.

⁸⁰ SMD NOPR, p. 11.

filings that allow for different distribution rules within each ITP.⁸¹ However, one compound distribution rule applies to all ITPs. All of the transmission capability within the service area of an ITP is to be offered for initial distribution to the selected subsets of existing transmission customers in the form of CRRs. At the same time, an ITP cannot cause the oversubscription of these rights by selling more CRRs than can be technically accommodated.⁸²

As envisioned by FERC, the utilization of CRRs pursuant to the Standard Market Design will be more extensive than is the utilization of financial transmission rights in PJM and New York. The current situation in PJM and New York is one where financial transmission rights provide a *perfect* hedge against for the cost of congestion for the counter-parties (i.e. the buyer and seller) to a bilateral electric energy transaction. This hedge can apply to no more than 37 percent of the electric power that is transmitted over the United States’ transmission network if we recall FERC’s estimate of the percentage of wholesale electricity sales under bilateral contract.⁸³

The FERC proposal for the initial apportionment of CRRs is to parcel out the CRRs on the basis of the current firm transmission customers’ historical use of the transmission network. FERC is faced with the implementation of a multi-step process to achieve this end. The first step is to determine the volume of physically feasible CRRs under normal operating conditions for the transmission network. As already indicated FERC proposes in this regard that the volume of CRRs is not to exceed the amount that is *simultaneously feasible* in light of the total transmission capability in the ITP’s service area under normal operating conditions. In the course of determining the simultaneous feasibility of the volume of CRRs, the ITP is not permitted to reduce the total transfer capability of its transmission network by the volume of transmission transfer capability that is needed to support the set of existing transmission customers.⁸⁴ *This condition is just another way of saying that FERC will not permit a native load preference to affect the volume of CRRs that will be available to be apportioned initially. That is, load-serving entities such as regulated electricity distribution companies will not be preferred transmission customers when it comes to the initial division of the available CRRs.*

The second step in this multi-step process is to determine the existing types of transmission customers that are eligible for an initial share of the available CRRs. FERC proposes the following schema in this regard. The available CRRs are to be divided initially between two types of transmission customers—LSEs providing bundled retail electricity services and all transmission customers such as direct-access customers that

⁸¹ SMD NOPR, p. 132.

⁸² SMD NOPR, p. 133.

⁸³ SMD NOPR, p. 3, Section III.C.

⁸⁴ SMD NOPR, p. 69.

are currently purchasing firm Point-to-Point Transmission Service under contract.⁸⁵ All of these existing transmission customers are to receive CRRs to the extent simultaneously feasible that match their current use of the transmission network. *LSEs providing bundled retail electricity services are expected to receive an initial apportionment of CRRs that will cover virtually all of the receipt and delivery points on the transmission network.* Existing transmission customers holding contracts for firm Point-to-Point Transmission Service will receive CRRs in the direction and at the locations of their receipt and delivery points.

The FERC proposal for the initial distribution of CRRs fully protects the regulated electricity distribution companies providing bundled retail electricity service as long as there is no shortage of available CRRs under normal operating conditions with respect to all combinations of the receipt and delivery points. The odds are in favor of this being case whenever a transmission system is not characterized by chronic transmission transfer capability constraints. *However, in those instances where there are chronic transmission constraints, it is possible that the regulated electricity distribution companies may come up short after the initial apportionment of CRRs. This possibility exists because FERC proposes to eliminate the existing native-load preference that currently exists for the regulated electricity distribution companies.*

If regulated electricity distribution companies do not have enough CRRs to cover their existing native load, then it is likely that these LSEs will have to pay congestion costs even under normal operating conditions. Recall these regulated electricity distribution companies do not receive enough CRRs because there is chronic congestion on the transmission network. *If this outcome is realized on a routine basis, it is inevitable that the FERC proposal for the initial distribution of CRRs will result in an increased price for bundled retail electricity services.*

There is a way out of the dilemma, but it may come at too high a price to state public utility commissions and bundled retail electricity customers. FERC is seeking comment on the treatment of existing transmission customers that purchase long-term firm Point-to-Point Transmission Service and who are not load-serving entities.⁸⁶ FERC believes it is inequitable under its Standard Market Design for these transmission customers to receive an initial distribution of CRRs because they will not pay a network access charge.⁸⁷ FERC proposes two alternative treatments of this class of transmission

⁸⁵ SMD NOPR, pp. 69-71, p. 83. Existing non-firm transmission service customers will not receive any CRRs. However, existing non-firm transmission service customers can place a limit on the amount of congestion charges that they are willing to pay as compared to the cost of not taking transmission service for the receipt and delivery point during the requested time period. This option tends to place a limiting value on CRRs.

⁸⁶ SMD NOPR, p. 98.

⁸⁷ SMD NOPR, pp. 98-99.

customer, that is, a long-term, firm Point-to-Point Transmission Service user that is neither a load serving entity nor a direct access customer.⁸⁸

One option is for this class of transmission customer to pay the network access charge and to receive CRRs that reflect current levels of the class' Point-to-Point Transmission Service. Another option is for this class of transmission customer to not pay the network access charge and not to receive an initial apportionment of CRRs. The latter option lowers the probability that regulated electricity distribution companies will come up short on CRRs, but it raises the network access charge that has to be paid by these LSEs. This trade-off might not favor bundled retail electricity customers. *Consequently, state public utility commissions may wish to evaluate the consequences of the second option even though it increases the probability of more reliable service for bundled retail electricity customers.*

There is another issue here associated with the second option for the treatment of existing transmission customers that purchase long-term firm Point-to-Point Transmission Service and who are not LSEs. On the one hand, this alternative lowers the generator's cost of delivering electric power. On the other hand, a low-cost generator that does not have CRRs because it does not pay the network access charge may be shut out from the delivery of electric power and hence not produce electric power. FERC may wish to consider this anti-competitive consequence of its proposed alternative.

There is a middle ground for policy makers that bears examination. Network access could be divided into originating network access and terminating network access. The originating network access would be associated with the receipt points of NAS, and the terminating network access would be associated with the delivery points of NAS. Generators would purchase originating network access. Load-serving entities would purchase terminating network access. *Then there would never be an instance where some generators pay a network access charge while other generators do not pay a network access charge, rendering concerns moot over any potential anti-competitive consequences of disparate cost responsibility.*⁸⁹

V. D: Subsequent Distribution of Congestion Revenue Rights

As proposed by FERC, the initial distribution of CRRs will eventually need to be re-allocated. Load patterns will change over time, and as a result transmission customers including regulated electricity distribution companies and other LSEs will want new configurations of CRRs. Also, some LSEs with CRRs will drop off the transmission

⁸⁸ SMD NOPR, p. 99.

⁸⁹ After adjustment for transmission losses, electric power that enters a transmission also leaves the transmission system. This fact along with an assumption that the conversion to originating and terminating access would neither increase nor decrease transmission usage implies that the price of NAS would not change.

network, and their CRRs may have to be re-distributed to the remaining LSEs if CRR auctions are not in operation. Of course, it is possible that CRR auctions will be operational at the closure of the initial distribution of CRRs, and as a result, subsequent distributions of CRRs can take place in the secondary market for CRRs. Additionally, new CRRs will be created by transmission investment that will have to be distributed in some manner.

V. D. 1: In the Absence of Congestion Revenue Rights Auctions

Suppose the time limitation on the initial distribution of CRRs has expired, and attempts to implement an effective CRR auction have failed. What is to happen to those transmission customers that had CRRs? FERC proposes that *some* of these customers should be allowed to maintain their current amounts of CRRs at their current locations if they want to do so.⁹⁰ The transmission customers that fall into this set are customers with a CRR obligation contract with a term of at least one year. But, these customers do not have an absolute right to maintain their current amounts and locations of CRRs.

Conceivably, an ITP will not be able to accommodate all of the requests for the extension of current amounts of CRRs in the desired locations. This could happen if other transmission customers without CRRs have submitted contracts for the contested CRRs with longer durations than the contracts submitted by the existing holders of these CRRs. FERC proposes that the existing holders of the contested CRRs can retain these CRRs if they agree to contracts with durations at least equal to the contract durations proposed by the contesting transmission customers currently without CRRs.⁹¹ In other words, qualifying transmission customers will have a right of first refusal for their existing CRRs.

V. D. 2: In the Presence of Congestion Revenue Rights Auctions

FERC proposes that an ITP conduct periodic auctions over OASIS for different types of CRRs. The auctions are to be conducted no less frequently than once a month.⁹² When operational the first auction will be restricted to bids to buy and sell receipt-point-to-delivery-point CRR obligations. This auction will be used for the sale of expired receipt-point-to-delivery-point CRR obligations. Auctions for flow-gate CRRs and receipt-point-to-delivery-point CRR options will be deferred until it is technically feasible to provide these alternative types of CRRs and market participants have requested them.

⁹⁰ SMD NOPR, p. 63.

⁹¹ SMD NOPR, p. 63.

⁹² SMD NOPR, p. 71.

All bids for receipt-point-to-delivery-point CRR obligations that are submitted to the ITP for consideration will be for specified durations for specified receipt and delivery points. FERC proposes that the ITP must consider all bids. This requirement alone may impose significant transaction costs on an ITP. However, there are more requirements. First, FERC propose that the ITP must choose a combination of bids that is simultaneously feasible in light of the transmission capability that is expected to be available for the pertinent time period.⁹³ For example, assume that the selected combination of bids includes bids with contract durations of five years. Then the measure of transmission capability would be the year-by-year forecast of total transmission capability from the beginning of first year to the end of the fifth year. Second, the combination of bids chosen by the ITP must maximize the combined net economic value of the auction (as expressed in the bids). Third, the auction has to allow for the reconfiguration of CRRs, that is, the newly requested CRRs can have different receipt and delivery points.⁹⁴

It is important to note that the FERC proposes that this auction process should be used to distribute CRRs that are created as a result of transmission investment meant to enhance the reliability of the transmission network. But this auction process does not impact the assignment of CRRs that are created by transmission investment funded by market participants.⁹⁵ If a market participant or participants completely finance the transmission investment, the participant or group of participants receive all of the CRRs created by the additional transmission transfer capability.⁹⁶ In this regard, FERC proposes that an ITP should develop a non-discriminatory methodology for allocating the newly created CRRs among a group of market participants that financed the new transmission facilities.⁹⁷ However, because this market participant or group of market participants has become a transmission owner, it must turn over the operation and control of the associated transmission facilities to the ITP.

V. D. 3: Secondary Market for the Resale of Congestion Revenue Rights

The purpose of a secondary market for CRRs is to provide a vehicle for LSEs and other market participants to acquire additional CRRs and to sell their unwanted CRRs.⁹⁸ The

⁹³ SMD NOPR, pp. 74, 76.

⁹⁴ SMD NOPR, pp. 71, 76.

⁹⁵ FERC proposes that it will not allow any transmission-investment project that makes existing CRRs infeasible due to loop-flow problems. SMD NOPR, p. 192.

⁹⁶ SMD NOPR, pp. 76,133.

⁹⁷ SMD NOPR, p. 77.

⁹⁸ SMD NOPR, p. 142.

secondary market for CRRs is a resale market, which means that newly created CRRs are not brought and sold in this market. FERC wants this market to be active (i.e. a lot of resale) because an active secondary market will provide liquidity for the periodic auctions subsequent to the initial distribution of CRRs, if they ever materialize. Bilateral transactions between those who want CRRs and those who have CRRs are the basic resale vehicle.

Whether a secondary market for CRRs governed only by bilateral transactions will result in an active secondary market is not known with certainty, but there are clear reasons for concern. Receipt-point-to-delivery point CRRs are direction-specific, which means that a buyer cannot automatically reconfigure a CRR that is brought in the secondary market pursuant to a bilateral transaction. Thus, the buyer will have receipt and delivery points identical to those of the seller of a CRR in the secondary market in order to gain full protection against congestion charges.⁹⁹ *Consequently, policy makers should not necessarily expect substantial electricity price mitigation for either the wholesale or retail markets from CRR resale in the context of bilateral transactions.*

FERC would like to expand the set of resale vehicles to include an auction for CRRs that are offered in the secondary market.¹⁰⁰ FERC believes that buyers and sellers should be able to submit bids into the secondary market that specify the desired CRRs' receipt and delivery points, the duration of the bid, and the bid.¹⁰¹ FERC also believes that an ITP should be able to put together buy and sell bids in such a manner that the economic value of the auction (i.e. returns the highest auction revenue) is maximized. Furthermore, FERC believes that an ITP may have to reconfigure the CRRs sold in the secondary market in order to maintain the simultaneous feasibility of CRRs in general and to maximize the proceeds from the auction.¹⁰² These beliefs suggest that the transaction costs associated with weekly auctions in the secondary market for CRRs will be quite high because the CRRs offered for sale are apt to differ in location from the CRRs offered for purchase in the secondary market. In this regard, it is useful to note that any reconfiguration of the CRRs sold at an auction conducted in a secondary market will have to occur before an ITP sets the market-clearing price for each CRR bought or sold at this auction. *Consequently, policy makers need to be aware that conducting an auction in a secondary market for CRRs may as likely increase as decrease the price of CRRs. At present, there is simply not enough experience or empirical data to evaluate the consequences.*

⁹⁹ SMD NOPR, p. 117.

¹⁰⁰ SMD NOPR, p. 143.

¹⁰¹ SMD NOPR, p. 143.

¹⁰² SMD NOPR, p. 143.

Another significant and legitimate concern for policy makers is that the operation of a secondary market for CRRs introduces pure speculation to congestion management. FERC intends that anyone—LSE or not – may purchase and subsequently sell CRRs in the secondary market either at auction or using a bilateral transaction.¹⁰³ In either case, it is pure speculation in CRRs if the buyer-turned-seller of CRRs never intended to purchase and transmit electric power from a receipt point to a delivery point. Pure speculation, unfortunately, is based on the maxim—“ buy low and sell high.” *Speculation may provide liquidity to the secondary market for CRRs; however, the potentially higher liquidity comes at a cost of potentially higher prices for CRRs sold in the secondary market as compared to CRRs sold in the periodic auctions for newly created and expired receipt-point-to-delivery-point CRRs.*

V. E: Characteristics of Tradable Congestion Revenue Rights

FERC intends to treat receipt-point-to-delivery-point CRRs as tradable financial rights.¹⁰⁴ This much is clear from the discussion in Section V. D. 3. It also is revealed through that discussion that tradable CRRs can introduce pure speculation into the transmission sector of an electric-power industry. Now, we set out to show how tradable CRRs can affect the optimality of a security-constrained dispatch.

V. E. 1: Trading or Reassignment of Congestion Revenue Rights

The NAS tariff does not prevent the trading or reassignment of CRRs.¹⁰⁵ Conversely, this transmission-service tariff does not mandate reassignment or trading of these rights. FERC, in fact, is counting on the development of a flourishing secondary market for CRRs. FERC’s position is premised on the assumption that transmission customers will be willing to incur the transaction costs that will accompany the creation of a *de novo* secondary market for CRRs. If such events do occur, then FERC believes that tradable CRRs will increase the flexibility of the transmission network for NAS users.¹⁰⁶ More specifically, transmission customers would find it easier to transmit electric power within the service area of an ITP without worrying about an uncertain congestion charge.

V. E. 1. a: Auctions, Swaps and Forward Contracts for Congestion Revenue Rights

¹⁰³ SMD NOPR, p. 142.

¹⁰⁴ SMD NOPR, p. 11.

¹⁰⁵ SMD NOPR, pp, 78, 80.

¹⁰⁶ SMD NOPR, p. 78.

It is implicit in FERC's reasoning that CRR holders either will use them in support of electric power delivery or offer them for sale through an auction in the secondary market. However, there is a third possibility. A CRR holder might not use them and might not auction them off. It is this third possibility that renders problematic the assumption that the mere construction of a *de novo* market for trading CRRs will result in the emergence of a liquid secondary market for CRRs. Therefore, it is problematic whether there actually will be a significant number of CRR sales in the secondary market.

It is more likely that there will be swaps of CRRs with or without cash side-payments. A bilateral transaction between a seller and buyer of CRR is a special case of a swap, where the seller exchanges the ownership of a CRR for cash. However, a swap may also be a simple trade, with no cash transaction involved. CRRs can be swapped in the same way that stamps or baseball cards are traded among adults and children. I have a receipt-point-to-delivery-point CRR at a location where I do not need it, and you have a receipt-point-to-deliver-point CRR at a location where you do not need it. But as fate would have it, I need the CRR that you have, and you need the CRR that I have. The solution to this problem is simple: We agree to trade our CRRs. The only transaction cost is finding each other, which will not be difficult considering how many LSEs will there be in the service of an ITP.

Another alternative to the auction of CRRs in a secondary market is a forward contract tied to generation assets. If an existing CRR holder knows that it will not need receipt-point-to-delivery-point CRRs for every moment of the duration of a multi-year CRR contract, then this CRR holder is in the position to sell a forward contract to a transmission customer without CRRs. In this way, the existing holder of CRRs retains control of the CRRs over the duration of a multi-year CRR contract, thereby reducing the transaction costs and making it more likely that multi-year contracts for CRRs actually will be entered into by an ITP and transmission customers.

V. E. 1. b: Speculation in Congestion Revenue Rights

Auctions and forward contracts not tied to generation assets in contrast to swaps of and forward contracts tied to generation assets for CRRs increase the likelihood of speculation in the secondary market for CRRs. This much is certain because FERC proposes that anyone will be able to buy or sell CRRs in the secondary market. This speculation, however, will be disguised as financial intermediation.

To see what is meant by disguised financial intermediation consider the following situation. An entity, which we will call the financial intermediary, buys CRRs at auction in the secondary market, but it does not intend to transmit electric power. This event, by definition, takes CRRs out-of-service unless the financial intermediary undertakes sales activity subsequently.

The financial intermediary, clearly, has a real incentive to swap CRRs when there is a cash side-payment that goes its direction, that is, the financial intermediary receives the

cash side-payment. But, this financial transaction is nothing more than speculation. The financial intermediary has a real incentive to buy a forward contract at a low price and then divide the acquired CRRs into smaller forward contracts of the same or less duration and sell these forward contracts at higher prices. These financial activities, in sum, also amount to speculation. The financial intermediary has a real incentive to resell its acquired CRRs at a subsequent auction for a higher price. Once again, this is speculation. *In short, a CRR holder that does not intend to transmit electric power is a speculator, regardless of how its activities are characterized.*

V. F: Periodicity of Congestion Revenue Rights Primary Auctions

As noted previously, FERC proposes that the initial distribution of CRRs to LSEs and other approved market participants such as direct-access customers will be based on historical data associated with the use of the transmission network. *Although the ownership status of the initially distributed CRRs is far from clear, it is apparent that FERC does not intend for some unspecified period of time to expose LSEs, such as regulated electricity distribution companies, to the uncertainties of CRR auctions. FERC notes that the periodic primary auctions of CRRs will not affect the CRRs that have been included in the initial distribution of CRRs and are still held by the market participants to whom the CRRs have been distributed.*¹⁰⁷

Three categories of CRRs are subject to periodic primary auction. First, there are CRRs given up by their initial holders without resale in the secondary market. Second, there are CRRs that have been given up by their secondary holders after unsuccessful attempts to resell again in the secondary market. Third, there are CRRs that have been created as a result of reliability-enhancing transmission investments, the cost of which has been rolled into the rate base of the ITP.

FERC proposes that the periodic primary auctions of CRRs begin some time during the first two years of an ITP's operation.¹⁰⁸ The periodicity for these auctions that has been suggested by FERC is contract terms of 1 year, 6 months and 1 month. Then, in the third year of its operation, an ITP shall offer CRRs with terms of 10 years and 5 years in addition to the by then already existing terms of 1 year, 6 months and 1 month. FERC also proposes that an ITP can offer CRRs of different contract durations, if requested by an eligible transmission customer.

VI. Conclusions

To state the obvious, market design flaws often result in unintended consequences—some of which may be simply bad outcomes. This analysis set out to uncover some of the

¹⁰⁷ SMD NOPR, p. 68.

¹⁰⁸ SMD NOPR, pp. 67-68.

implications associated with the Standard Market Design in general and Congestion Revenue Rights in particular. Arguably, the most important of the implications of FERC's proposed Standard Market Design is that, so construed, tradable Congestion Revenue Rights would permit speculation, which in turn has the potential to drive up transmission prices to the detriment of load-serving entities and retail customers. The analysis has also demonstrated other aspects of the SMD NOPR that could result in upward pressure on bundled retail electricity service prices, as well as aspects of the NORP that could affect service reliability.

State regulatory authorities and federal regulatory authorities alike want any reform of the electricity industry to result in adequate and reliable supplies of electric energy at a just and reasonable price. However, the state authorities are concerned primarily with retail electricity prices while the federal authority is concerned primarily with the wholesale price. There would not be any dissonance of interest if the wholesale and retail electricity markets were competitive in the sense of manifesting merely negligible market power. However, wholesale and retail electricity markets in the United States are not competitive in this sense. Consequently, the interests of state and federal regulatory authorities are likely to diverge, absent the development and implementation of comprehensive policies to mitigate market-power abuses.