

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Remedying Undue Discrimination through
Open Access Transmission Service and
Standard Electricity Market Design

Docket No. RM01-12-000

Summary of Comments of Industrial Consumers

The Electricity Consumers Resource Council (ELCON), the American Chemistry Council (ACC), and the American Iron and Steel Institute (AISI), collectively referred to as “Industrial Consumers,” submit these additional comments in response to FERC’s July 31, 2002 Notice of Proposed Rulemaking (NOPR). These comments supplement our initial comments filed November 15, 2002 and address five separate issues identified in the Commission’s October 2, 2002 Notice of Conferences and Revisions to Public Comment Schedule.

I. Market Design for the Western Interconnection

Industrial Consumers believe that a separate market design for the Western Interconnection should be allowed to evolve consistent with FERC’s Orders on RTO West and WestConnect. Nonetheless, Industrial Consumers support standardized products and services in the West with the same “look and feel” as the comparable products and services in the East. Departures from the basic SMD template should not be used to obstruct the development of competitive markets at either the wholesale or retail level. (¶¶ 211-220)

II. Transmission Planning and Pricing, Including Participant Funding

Industrial Consumers support the need for an adequate transmission infrastructure. However, we are wary of the motives behind so-called Participant Funding, and believe that

some Transmission Owners may be deliberately under-building transmission to preserve their generation market power and their retail market share.

A. Industrial Consumers Generally Support the NOPR’s Proposed Method for Recovering the Costs of New Transmission Facilities. Any Application of Participant Funding or Rolled-In Rate Treatment Should Be Carefully Evaluated by an Independent, Regional Planning Process. (¶¶ 191-202)

The Commission proposes to consider the use of Participant Funding for new transmission facilities only if the proposed facilities are included in a regional planning process which is conducted by an independent entity, whether an RTO, ISO, or some other independent entity. But in the absence of independence, the NOPR proposes to apply a default pricing policy that would roll-in, on a region-wide basis, all high voltage network upgrades of 138 kV and above. Industrial Consumers support this proposed default pricing policy and process subject to conditions stated below. We also recommend lowering the voltage threshold for the default policy to 69kV.

Industrial Consumers do not oppose the general principle behind Participant Funding, only the potential harm resulting from the misapplication of this cost recovery method that betrays the true principles of cost causation. Historically, every retail customer has benefited from the costs of every transmission upgrade. Simply stated, Participant Funding intends to allocate the costs of transmission construction and upgrades to the beneficiaries. But most transmission investments are characterized by their “lumpiness,” *i.e.*, they are not predicated on incremental needs. This characteristic makes it difficult to apply a strict form of Participant Funding that assigns the investment costs to a limited, discrete set of beneficiaries. Further, to do so in a competitive market amounts to a form of vintage pricing that is patently discriminatory because generation owned by the incumbent utilities will have benefited from transmission that received rolled-in rate treatment. Regulators should exercise considerable discretion when

evaluating the merits and financing of any new transmission projects needed for connections to new load or new generation additions. The risk is relatively low that too much transmission will be built and considerably higher that too little will be built, causing great harm to customers. The “lumpiness” of transmission projects results from the technology’s scale economies and network attributes. Incremental expansions are highly likely to be inefficient in both the near term and long run and therefore more costly to customers. For these reasons, Industrial Consumers support rolled-in rate treatment of new transmission investment unless a compelling case is made for other treatment.

Rolled-in rate treatment is clearly appropriate for a new transmission project if it is: (1) necessary to maintain or improve reliability, and/or (2) will likely increase economic benefits to customers in excess of the project’s cost. It is essential that the rate treatment of new transmission projects be subject to a regional planning process that includes a strong role for stakeholders. A Transmission Owner must not be allowed to unilaterally determine the rate treatment of new projects to ensure that the Owner does not benefit from rolled-in rate treatment for projects that only confer a competitive advantage to its own generation, or does not use Participant Funding to discriminate against potential competitors. If a Transmission Owner seeks rolled-in rate treatment in the absence of a regional planning process, it must prove that the project’s benefits to ratepayers will exceed the project’s costs. Participant Funding may be required where a new project will only benefit an identifiable customer or group of customers. If the benefits begin to accrue to a broader group of customers, a crediting mechanism should be established to reimburse or compensate the original funding participants.

B. Industrial Consumers Recommend That FERC Require Transmission Owners to Show Due Diligence/ Reasonable Efforts to Ensure Transmission Adequacy As a Condition of Market-based Rate Authorization or as a Market Power Mitigation Measure.

Vertical integration creates powerful economic incentives to withhold transmission and therefore increase or maintain the value of affiliated generation resources, deny competitors market access, or gain congestion rents where local market power is preserved. In states with retail access, an under-built transmission system also helps a utility retain its retail market share by restricting end-use customers' access to more affordable alternatives.

Industrial Consumers believe that pursuant to FERC's mandate under § 205 of the Federal Power Act (FPA) to assure just and reasonable rates, and FERC's mandate under § 206 to redress undue discrimination, that the Commission should require transmission owners to show due diligence/reasonable efforts to ensure transmission adequacy as a condition of market-based rate authorization and as another market power mitigation measure in the SMD rule.

1. FERC Recognized in Docket EL01-118-000 That Section 206 Gives FERC Authority To Revoke Market-Based Rates If Market Power Is Exercised.

FERC recognized in its order launching the Investigation of Market-based Rates that it has a statutory obligation to assure that rates charged by entities with market-based rate authority are just and reasonable and do not reflect the exercise of market power.

2. Adequate Mitigation of Market Power Must be an Essential Precondition of Any Application of Market-Based Rates.

As a precondition to obtaining approval to charge market-based rates, the seller and its affiliates must show that they lack generation and transmission market power or mitigate any market power that they may have. The major concern of the Commission should be whether the seller or its affiliates can limit competition and thereby unduly drive up prices. If the seller or its affiliates owned or controlled transmission facilities it could, by denying access or imposing

discriminatory terms or conditions on transmission service, foreclose other generators from competing.

Open access under Order No. 888 is insufficient to mitigate market power where transmission is constrained. To assure that mitigation of transmission power is meaningful, on a case-by-case basis FERC must adjudicate that utilities have exercised best efforts/due diligence to relieve transmission constraints and that utilities have not deliberately exercised market power by unreasonably refusing to expand.

3. The Commission's Authority To Allow Market-Based Rates Requires That Market Power Be Mitigated.

FERC may be vulnerable on judicial review if it routinely grants market-based rate approvals based solely on a finding that an OATT exists and its decision is challenged on the basis that due to unreasonable failure to expand transmission, the transmission-owning utility has deliberately exercised market power in transmission.

4. Order No. 888 Requires Transmission-Owning Utility to Expand Transmission Facilities to Meet Firm Commitments to Avoid Exercises of Market Power; It is a Logical Extension to Impose the Duty to Expand to Non-Firm Commitments Where Necessary to Avoid a Given Utility's Exercise of Market Power.

FERC recently addressed the circumstances under which a Transmission Owner can be required to build new transmission in *NEPOOL*, 100 FERC ¶ 61,259 (September 6, 2002). In this order, FERC explained why the Order No. 888 obligation to build additional facilities does not apply in unique circumstances such as the Cross Sound merchant transmission project. What is significant is the discussion comparing merchant transmission facilities with vertically-integrated transmission owners who may exercise market power when they refuse to expand transmission facilities. The OATT imposes a duty to expand transmission for firm transmission customers on the conventional IOU subject to compensation. *See* Order No. 888 final rule, 61

Fed. Reg. 20,540 (1996), Tariff provisions §§ 13.5, 15.4 and 27. The OATT establishes the principle that a duty to build facilities may be necessary to redress market power, although the OATT is limited to “firm” transactions.

5. Expansion of Transmission Facilities Should Also be Ordered Under the Market Power Mitigation Features of the SMD Rulemaking.

Despite the recognition that transmission infrastructure may bear on market power, the NOPR’s market power mitigation provisions are limited to measures related to generation market power such as must-run units and bid caps. While these measures are much needed to address other incidents of market power, the NOPR does not go far enough to address market power caused by transmission constraints that vertically-integrated utilities have no incentive to resolve. FERC should utilize its § 206 authority to put teeth into the requirement that ITPs dictate *compensated* transmission upgrades where necessary to mitigate market power.

6. The Essential Facilities Doctrine Provides Support for the Relief Requested Herein.

Industrial Consumers do not argue that in every instance a transmission monopolist’s refusal to upgrade transmission facilities is inevitably an example of monopoly leveraging or a violation of the Sherman Act. However, denial of access to essential facilities on reasonable terms raises serious competitive concerns and justifies FERC scrutiny to assure itself that the conduct is not anticompetitive and an abuse of market power.

Thus, FERC has the authority and duty under § 205 and § 206 to revoke market-based rates where generation or transmission market power threatens achievement of just and reasonable, non-discriminatory rates. In Docket No. EL01-118-000, FERC proposed to revise market-based rate approvals prospectively to incorporate a condition allowing FERC to revoke market-based rate authority and/or impose refund obligations if the Commission found economic or physical withholding of supply. The same logic would apply if, on a case-by-case basis,

FERC finds that a given utility in an exercise of market power has failed to provide reasonable transmission access to competitors through unreasonable refusal to expand facilities.

Transmission is the paradigmatic essential facility and deliberate under-building can result in withholding and discrimination against competitors.

In addition or alternatively, in the SMD rule, FERC could require that ITPs or RTOs address market power abuse by ordering compensated transmission expansion where it is necessary and cost-effective to relieve congestion. Where market power is found to exist due to constrained transmission facilities, the RTO or the ITP could be charged with requiring a demonstration of best efforts/due diligence by transmission owners to relieve the constraint.

III. Regional State Advisory Committees and State Participation

Industrial Consumers encourage state regulators to actively participate in each ITP or RTO's stakeholder process. (¶¶ 551-555)

Industrial Consumers are concerned that the NOPR's proposal to establish Regional State Advisory Commissions creates a potential new layer of regulation. The open-ended charge and regional discretion given to these committees creates the potential for state or local interference in interstate electricity markets that would nullify the noble objectives of SMD. We do not oppose a strong role for states in the affairs of ITPs, but that role should be at the table with other stakeholders in each ITP's stakeholder process. We see no evidence from the experience of ISOs that such a role does not provide adequate representation of state interests. States that seek a stronger voice in the RTO or ITP process should do so by becoming voting members of the stakeholder advisory committee. Should they elect that venue, they should be included in a sector reserved for public interest groups—not with end users.

IV. Resource Adequacy

Resource adequacy and forward contracting are important federal policy objectives, but the breadth and scope of the NOPR proposal is unnecessary and needlessly complex. (¶¶ 457-550) Industrial Consumers support the NOPR’s conclusion that the Installed Capacity (ICAP) requirement should not be imposed as a national standard. (¶ 483) We also believe that requiring ITPs to ensure sufficient resource adequacy as prescribed in the NOPR is beyond the Commission’s statutory authority. (¶¶ 457-550) We urge FERC to adopt a forward-looking resource adequacy requirement on an interim basis with a default regional reserve margin (12%). (¶ 493) We also recommend that each ITP be required to conduct a simple auction for the amount of resources needed to meet the default regional reserve margin. (¶¶ 494-519)

V. Congestion Revenue Rights (CRRs) and Transition Issues

Industrial Consumers support the allocation of the value of the transmission system exclusively to LSEs and Market-Participating Loads by either direct assignment or auction. In either case, the value of the transmission system should always “follow the load.” (¶¶ 376-382) Industrial Consumers are concerned that if the market value of the transmission system—as represented by Congestion Revenue Rights or CRRs—is separated from end-use customers who ultimately pay for the transmission system, some market participants will unduly profit at the expense of consumers by using CRRs to game their bids and generation dispatch and not for their intended purpose which is to allow customers to hedge congestion costs. We are also concerned that if there is not a sufficient amount of CRRs available in the market, end-use customers (or their suppliers) may not be able to hedge their transactions against congestion, and power markets will remain unnecessarily unstable and potentially face future reliability problems. These concerns form the basis for our position on the allocation of CRRs by either direct assignment or auction.

Industrial Consumers support the direct assignment of CRRs in some reasonably short transition period to LSEs and all Market-Participating Loads (MPLs). Auctions should be delayed until LSEs and MPLs have some experience with the new market mechanics and some understanding of the innate value of the CRRs that they hold. We believe that CRRs or the market value of CRRs as determined by auction should be allocated directly to end-use customers based on the historic use of the transmission system by their historic supplier.

Industrial Customers also recommend that the Commission not permit any entities other than LSEs and MPLs (or their agents) to hold CRRs or participate in auctions until such time there has been a determination by the Commission that such other entities—*e.g.*, generators or ITCs—lack market power such that they cannot abuse the congestion management system through the ownership of CRRs. CRRs will be scarce even under the best of circumstances. It is not sound public policy to allow CRR ownership for the purpose of gaming the dispatch process.

Industrial Consumers believe that FERC has an obligation to ensure reliable and reasonably stable competitive markets. Therefore, it is vital that the transition to and allocation of CRRs support a liquid and transparent forward market for transmission rights that ultimately reaches out to the horizon of new generation and transmission construction. The forward locational price discovery necessary to provide the “lead compensation” necessary to make markets stable can only be derived from the forward trading of CRRs to hedge expected LMP charges, not the LMP charges themselves.

To ensure reasonably stable markets and that consumers can adequately hedge themselves against LMP congestion charges, a sufficient number of CRRs must be available to the market by auction or in the secondary markets. This means that ultimately all allocated CRRs must be auctioned and the market value of those CRRs must be allocated rather than the

CRRs themselves. It also means in those regions where a substantial amount of the total CRRs have been allocated, a move to mandatory auctions (*i.e.*, the allocation of the value of CRRs rather than the CRRs themselves) will need to happen sooner rather than later. Moreover, in such situations, an allocation of CRRs rather than the value of CRRs will be an impediment to retail access as it will be difficult for end-use customers (or their suppliers) to obtain the CRRs required to fully hedge their transactions against LMP charges.

Industrial Customers are concerned that the delay towards moving to allocating the revenues from the allocated CRRs, rather than the CRRs themselves, will undermine the liquidity in the market for CRRs such that LSEs and MPLs will not be able to obtain sufficient CRRs from either the ITP or the secondary market to adequately hedge their bilateral transactions against congestion charges. CRRs may be allocated on a *pro rata* basis based on the incumbent utility's historical usage of the transmission system to serve its native load. Release of these CRRs to LSEs or MPLs on a load ratio share basis will provide the value of the transmission system for which transmission customers have historically paid, but it will not necessarily provide them with CRRs that are useful to hedge bilateral transactions against congestion charges and the incumbent may still have locked-up the lion's share of the CRRs. By only allocating the value of the allocated CRRs as determined in the ITP auction, rather than the CRRs themselves, LSEs and MPLs will be able to receive the value of the transmission system while still being able to acquire the specific CRRs they need to hedge their bilateral transactions against congestion charges. The Commission should require that the auction revenues from allocated CRRs, rather than the CRRs themselves, be awarded to LSEs and MPLs where retail access has been introduced.

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The Electricity Consumers Resource Council (ELCON), the American Chemistry Council (ACC), and the American Iron and Steel Institute (AISI), collectively referred to as “Industrial Consumers,” welcome the opportunity to submit comments in response to the Federal Energy Regulatory Commission’s July 31, 2002 Notice of Proposed Rulemaking (NOPR) on remedying undue discrimination through open access transmission service and standard electricity market design. These comments supplement our initial comments filed November 15, 2002 and address five separate issues identified in the Commission’s October 2, 2002 Notice of Conferences and Revisions to Public Comment Schedule: (1) market design for the Western Interconnection; (2) transmission planning and pricing, including participant funding; (3) Regional State Advisory Committees and state participation; (4) resource adequacy; and (5) CRRs and transition issues.

I. Comments of Industrial Consumers

Industrial Consumers strongly support the restructuring of the U.S. electric industry at both the wholesale and retail levels. In fact, we believe that a competitive market is ultimately a single market that cannot be encumbered with an artificial jurisdictional division that currently

categorizes and segregates interstate transmission -- based upon service for “wholesale” or “retail” transactions. This division of interstate transmission is the result of historical coincidence, is not supported by physics or the “commingling” theory, and is a significant burden on interstate commerce. Lack of centralized, federal regulatory jurisdiction over all interstate transmission has inhibited needed development of robust wholesale power markets due to inconsistent market rules and protocols. Standardized markets or market products would eliminate or diminish these regional differences and establish a basis for compensation of transmission investment needed to alleviate known constraints, which would improve physical reliability and economic predictability of energy delivery on a regional basis. End-use customers of all sizes are harmed by the perpetuation of the artificial jurisdictional split over interstate transmission based on transaction type — wholesale and unbundled retail transactions *versus* bundled retail transactions. This division, while purportedly supporting states’ rights, actually diminishes individual consumer rights by denying consumers the benefits of customer choice and innovation, typical of well-functioning commodity markets. The five issues identified in the Commission’s October 2 Notice are largely symptomatic of parochial concerns that would preserve the inefficient regulated industry and the historic allocation of political control and market shares to various incumbent parties. Such pressures are not an attempt to promote efficiency or deliver more customer-focused products and services to end-use customers. We strongly urge the Commission to resist such pressures and to expeditiously implement its long overdue restructuring initiative.

A. Industrial Consumers Believe that a Separate Market Design for the Western Interconnection Should be Allowed to Evolve Consistent with FERC’s Orders on RTO West and WestConnect. Nonetheless, Industrial Consumers Support Standardized Products and Services in the West with the Same “Look and Feel” As the Products and Services in the East. (¶¶ 211-220)

The Western Interconnection has a distinctly different physical resource base compared to the Eastern Interconnection or ERCOT. Sponsors of western RTO proposals cite other differences. For example, control areas in the Eastern Interconnection must be operated and centrally dispatched to account for minimal storage capability. In the West, there is significant hydroelectric storage capability that allows producers to alter their production decisions on an inter-temporal basis.¹ The extent to which such differences preclude full implementation of the SMD in the West is an open question. These differences are captured in the proposed market design of RTO West and to a lesser extent in the proposed market designs of WestConnect and the CAISO. Nonetheless, RTO West and CAISO are adopting major features of the SMD, a recent FERC order encouraged WestConnect to do the same, and the entire West is actively engaged in resolving “seams” problems between the three ISOs/RTOs with the intent of creating a single market.² While Industrial Consumers have long advocated a single RTO for the West, it is *a single market* that is most important, not the institutional platform. We are confident that once a single market has been established, and proven its worth, the benefits of a single RTO/ITP structure will compel institutional consolidation. *A recent MOU was signed by RTO West, West Connect and Cal ISO to jointly work to resolve seams issues within the relative market structures.*

¹ Comments of the Industrial Customers of Northwest Utilities, Docket No. RM01-12-000 (“Electricity Market Design and Structure Notice of Working Paper”), April 10, 2002.

² The Seams Steering Group – Western Interconnection (SSG-WI), whose members include CAISO, RTO West and WestConnect – was established to facilitate implementation of one seamless, west-wide market with “common business practices, no trade barriers and minimum transaction costs.” Bud Krogh, “The Future of Market Monitoring in the West,” SSG-WI, November 16, 2001.

In its September 18, 2002 order on RTO West’s Stage 2 filing, and also in its October 10, 2002 order approving WestConnect’s motion for declaratory order, FERC ruled that:

... unless the Commission has specifically indicated in this order that an element of the RTO proposal is inconsistent with the SMD proposal or needs further work in light of the SMD proposal, we do not intend, in the final SMD rule, to revisit prior approvals or acceptances of RTO provisions because of possible inconsistencies with the details of the final rule.

The Commission has recognized that a strict application of SMD—a market design that evolved from tight power pools that only existed in the Eastern Interconnection—in the West may not be prudent in the near term and a limited departure from the SMD template may be warranted. Industrial Consumers believe that a separate market design should be allowed to evolve in the West provided that it is consistent with the RTO West and WestConnect orders and is otherwise justified based on any unique physical attributes of the Western Interconnection. Departures from the basic SMD template, however, should not be used to obstruct the development of competitive markets at either the wholesale or retail level. It is imperative that the transmission products and services in the West have the same “look and feel” as comparable products and services in the Eastern Interconnection. A true national (or continental) market—with standardized products and services—must be the end state or the goal of the restructuring process. The gaming of Western markets that attended the collapse of the California market in 2000 was enabled, in part, by the lack of standardization across state or interregional boundaries. A repetition of such behavior can only be prevented by the adoption of a common market design and business practices across the West.

B. Industrial Consumers Strongly Support the Need for an Adequate Transmission Infrastructure. However, We Remain Wary of the Motives Behind So-called “Participant Funding,” and Believe That Some Transmission Owners May be Deliberately Under-Building Transmission to Preserve the Market Power of Their Affiliates or the Utilities’ Generation.

1. Industrial Consumers Generally Support the NOPR’s Proposed Method for Recovering the Costs of New Transmission Facilities. However, Any Application of Participant Funding or Rolled-In Rate Treatment Should Be Carefully Evaluated by an Independent, Regional Planning Process. (¶¶ 191-202)

The Commission proposes to consider the use of “participant funding” for new transmission facilities only if the proposed facilities are included in a regional planning process that is conducted by an independent entity, whether an RTO, ISO, or some other independent entity. Participant funding also should be considered for transmission enhancements approved by the RTO/ISO or ITP in any revised plan. In the absence of independence, the NOPR proposes to apply a default pricing policy that would roll-in, on a region-wide basis, all high voltage network upgrades of 138 kV and above. Industrial Consumers support this proposed default pricing policy and process. We also recommend lowering the voltage threshold for the default pricing policy to 69kV.

Industrial Consumers do not oppose the general principle behind “participant funding,” only the potential harm resulting from the misapplication of this method of cost recovery. Simply stated, participant funding intends to allocate the costs of transmission construction and upgrades to the beneficiaries. But most transmission investments are characterized by their “lumpiness,” *i.e.*, they are not predicated on incremental needs. This characteristic makes it difficult to apply a strict form of participant funding that essentially assigns the investment costs to a limited, discrete set of market participants. Further, to do so in a competitive market amounts to a form of vintage pricing that is patently discriminatory. Regulators should exercise

considerable discretion when evaluating the merits and financing of any new transmission projects needed for connections to new load or new generation additions. The risk is relatively low that too much transmission will be built and considerably higher that too little will be built at great harm to customers. The “lumpiness” of transmission projects results from the technology’s scale economies. Incremental expansions may be inefficient in both the near and the long run and more costly to customers. For these reasons, Industrial Consumers support rolled-in rate treatment of new transmission investment unless a compelling case is made for other treatment.

Rolled-in rate treatment is clearly appropriate for a new transmission project if it is: (1) necessary to maintain or improve reliability, and/or (2) will likely increase economic benefits to customers in excess of the project’s cost. It is essential that the rate treatment of new transmission projects be subject to a regional planning process that includes a strong role for stakeholders. A Transmission Owner must not be allowed to unilaterally determine the rate treatment of new projects to ensure that the Owner does not benefit from rolled-in rate treatment for projects that only confer a competitive advantage to its own generation, or does not use participant funding to discriminate against potential competitors. If a Transmission Owner seeks rolled-in rate treatment in the absence of a regional planning process, it must prove that the project’s benefits to ratepayers will exceed the project’s costs. Participant funding should be required where a transmission project will only benefit an identifiable customer or group of customers. If the benefits begin to accrue to a broader group of customers, some form of crediting mechanism should be established to reimburse or compensate the original funding participants.

The NOPR’s proposal that an independent entity, such as an RTO or ITP, determine the applicability of participant funding is a positive step and we support this proposal in concept.

This is especially important if the transmission owner is part of a vertically integrated utility system. We are also concerned that the criteria established by some advocates of participant funding assume the continuation of the contract-path method of transmission pricing. In the context of SMD, this assumption is frivolous because SMD explicitly abandons the “contract path.”

Where multiple beneficiaries exist, participant funding and rolled-in rate treatment converge as cost allocation methods—the only difference being the number of customers who are allocated a rolled-in portion of the investment. Other provisions in the NOPR’s transmission pricing proposals may contribute to the convergence of rolled-in treatment with participant funding in a truly unified fashion—provided cost causation principles are consistently applied. This is a very desirable outcome and we urge the Commission to pursue it. For example, the inter-regional transmission service-pricing proposal may help accomplish this objective and, therefore, we also support this pricing proposal because it eliminates a potential source of transmission “free-riders” by expanding the regional coverage of embedded rates.³ The free-ridership issue is a major argument advanced by proponents of unadulterated participant funding.

But absent from the NOPR is any candid assessment of some of the real impediments to new transmission upgrades and investments, including state-mandated retail rate freezes and the unwillingness of many utilities to expose their existing allowed return on their rate bases to renewed scrutiny as a condition to recovering new investments. These are the problems that need to be recognized and addressed, otherwise, any discussion of “participant funding” or “incentives” may, in many cases, be a diversion. Lastly, but perhaps most important, Industrial

³ We address below (pages 35-39) inter-regional transfers and inter-regional pricing in our responses to the Commission’s direct questions and requests for comments in ¶¶ 186-190.

Consumers believe that many transmission owners are deliberately under-building the transmission system to preserve the market power of their generation and retail affiliates. We address this concern in detail below.

As discussed in our November 15, 2002 comments, Industrial Consumers oppose the proposition that these problems can be solved by putting for-profit Independent Transmission Companies (ITCs) in charge of RTOs or the new ITPs. Transmission ownership is a monopoly, and incumbent transmission owners are capable of exercising undue influence as policymakers debate the form and number of “incentives” necessary to induce them to do their job. They can exercise this influence because, given the nature of state siting laws and regulations, the “market” for transmission upgrades is not very contestable. Industrial Consumers urge the Commission not allow these monopolists to dictate the terms (and price) for meeting such basic public interest responsibilities—all in the name of infrastructure adequacy.

Industrial Consumers believe that an honest debate on participant funding must produce a transmission pricing policy that: (1) adheres to strict principles of cost causation, (2) establishes a clear set of rules for cost allocation and recovery that is fair and nondiscriminatory, (3) is not unduly burdensome to competitive entry in competitive regional markets, and (4) facilitates investment in adequate transmission infrastructure to improve physical reliability and economic viability in support of the “just and reasonable” rate mandate under which the Commission must operate.

Whether there is motive or not, treating existing generation owned by incumbents or sold by utility incumbents to third parties differently than new generation connected to the transmission grid provides a distinct competitive advantage to incumbent generation. For example, in Texas interconnection costs are kept to a minimum and transmission expansion costs

are considered on a regional basis with certainty in compensation for transmission investment for approved projects.

2. Industrial Consumers Recommend That the Commission Require Transmission Owners to Show Due Diligence/Reasonable Efforts to Ensure Transmission Adequacy As a Condition of Market-based Rate Authorization Or Alternatively as Another Market Power Mitigation Measure.

Vertical integration creates powerful economic incentives to withhold transmission expansion to increase (or maintain) the value of affiliated generation resources, to deny competitors access to the grid, and to gain congestion rents where local market power is preserved. In states that have authorized retail access, an under-built transmission system also helps a utility retain its retail market share by restricting end-use customers' access to more affordable alternatives. Industrial Consumers believe that pursuant to FERC's mandate under § 205 of the Federal Power Act (FPA) to assure just and reasonable rates, and FERC's mandate under § 206 to redress undue discrimination, that the Commission should require transmission owners to show due diligence/reasonable efforts to ensure transmission adequacy as a condition of market-based rate authorization and as another market power mitigation measure in the SMD rule.

- a. FERC Recognized in the Market-Based Rates Investigation Docket EL01-118-000 That Section 206 Gives FERC Authority To Revoke Market-Based Rates If Market Power Is Exercised.

FERC recognized in its order establishing the Market-based Rates Investigation docket (EL01-118-000) that it has a statutory obligation to assure that rates charged by power marketers and other utilities with market-based rate authority are just and reasonable and do not reflect exercise of market power:

In today's electric industry, the Commission is faced with power and energy sales markets that are increasingly interstate in nature and increasingly dependent upon one another, and with power and energy sales markets that are in varying stages of transition to competition at the wholesale and, in numerous states, the retail level. We have a responsibility under the FPA to monitor wholesale markets to ensure that jurisdictional rates in the markets remain within a zone of reasonableness. *Our responsibility is to ensure that sellers not charge unjust and unreasonable wholesale rates, and that the market structures and market rules governing public utility sellers nationwide, and affecting the wholesale rates of such public utility sellers, do not result in, or have the potential to result in, wholesale rates that are unjust, unreasonable, unduly discriminatory, or preferential. We have become increasingly concerned about the potential that public utilities with market-based rate authorization might, under certain circumstances, exercise market power or engage in anticompetitive behavior that could result in unjust or unreasonable rates.*

Although we do not find here that particular sellers have, for example, exercised market power, we propose to take steps now to minimize the potential for any such market power abuse or anticompetitive behavior and thus protect against possible unjust and unreasonable rates. Pursuant to FPA section 206, we are establishing a refund effective date 60 days from the date on which notice of initiation of this investigation is published in the Federal Register and seek comments on our proposal to revise all market-based rate tariffs and authorizations in effect to condition public utility sellers' market-based rate authority to prevent anticompetitive behavior or the exercise of market power.

November 20, 2001 Order in Docket No. EL01-118-000, Order Establishing Refund Effective Date and Proposing to Revise Market-Based Rate Tariffs and Authorizations (emphasis added).⁴

The Market-based Rates Investigation docket focused on physical and economic withholding of generation. FERC would impose refunds or the sanction of revocation of market-

⁴ FERC proposed that prospectively market-based rate tariffs would include a generic refund condition:

“In particular, all such market-based rate tariffs and authorizations would be revised to include the following provision: ‘As a condition of obtaining and retaining market-based rate authority, the seller is prohibited from engaging in anticompetitive behavior or the exercise of market power. The seller’s market-based rate authority is subject to refunds or other remedies as may be appropriate to address any anticompetitive behavior or exercise of market power. We will also require that this provision be included in all new market-based rates tariffs and authorizations. Violation of such provision would constitute a violation of a tariff or rate schedule on file under FPA section 205, and the Commission would have the authority to address promptly potential instances of anticompetitive behavior or exercises of market power through the imposition of refunds or such other remedies as may be appropriate.’”

based rate authority if case-by-case review indicates that the utility has engaged in prohibited behavior. The same statutory authority and objectives would justify a similar utility-specific review of whether transmission-owning utilities have exercised market power by unreasonably failing to expand their transmission system.

b. Adequate Mitigation of Market Power Must be an Essential Precondition of Any Application of FERC's Market-Based Rate Authorization.

As a precondition to obtaining approval to charge market-based rates, the seller and its affiliates must show that they lack generation and transmission market power or mitigate any market power that they may have. The major concern of the Commission was whether the seller or its affiliates could limit competition and thereby unduly drive up prices. If the seller or its affiliates owned or controlled transmission facilities it could, by denying access or imposing discriminatory terms or conditions on transmission service, foreclose other generators from competing. FERC explained in Order 888, 75 FERC ¶ 61,080 (1996): “The most likely route to market power in today’s electric utility industry lies through ownership or control of transmission facilities.” FERC’s requirement that utilities mitigate market power by affording comparable access was imposed as a condition of approval for power producers to charge market-based rates⁵ and as a condition of merger approval⁶ long before adoption of Order 888. In *Heartland Energy Services, Inc.*, 68 FERC ¶ 61,223 (1994), the Commission applied its comparability standard to an affiliated electric power marketer seeking blanket authorization to sell electricity at market-based rates. The Commission explained that for all future cases

⁵ See, e.g., *Ocean State Power*, 44 FERC at ¶ 61,261 (1988); *Commonwealth Atlantic Limited Partnership*, 51 FERC ¶ 61,368 (1990); *Citizens Power & Light Company*, 48 FERC ¶ 61,210 (1989); *Orange and Rockland Utilities, Inc.*, 42 FERC ¶ 61,012 (1988); *Doswell Limited Partnership*, 50 FERC ¶ 61,251 (1990); and *Dartmouth Power Associates Limited Partnership*, 53 FERC ¶ 61,117 (1990).

⁶ *El Paso Elec. Co.*, 68 FERC ¶ 61,182 (1994).

involving blanket approval of market-based rates “an offer of comparable transmission services will be required before the Commission will be able to find that transmission market power has been adequately mitigated.” In the context of an affiliated power marketer, this has meant that all of its affiliated utilities must have a comparable transmission tariff on file. Post Order 888, the open access requirement in power marketer approval dockets is a superfluous condition given that a FERC rule imposes open access on all transmission owners.

Open access, by itself, is insufficient to mitigate market power where transmission is constrained. To assure that mitigation of transmission power is meaningful, on a case-by-case basis FERC must adjudicate that utilities have exercised best efforts/due diligence to relieve transmission constraints and that utilities have not deliberately exercised market power by unreasonably refusing to expand its system.

c. The Commission’s Authority To Allow Market-Based Rates Requires That Market Power Be Mitigated.

FERC may be vulnerable on judicial review if it continues to routinely grant market-based rate approvals based solely on a finding that an open access tariff exists and its decision is challenged on the basis that due to unreasonable failure to expand transmission, the transmission-owning utility has deliberately exercised market power in transmission.

Section 205 of the FPA provides: “All rates and charges made, demanded, or received by any public utility for or in connection with the . . . sale of electric energy subject to the jurisdiction of the Commission and all rules and regulations affecting or pertaining to such rates or charges shall be just and reasonable and any such rate or charge that is not just and reasonable is hereby declared to be unlawful.” 16 U.S.C. Section 824d(a). The overriding purpose of prohibiting unjust and unreasonable rates and charges is “to protect consumers from exorbitant prices and unfair business practices. This purpose can be seen in the statutory requirement that

rates be just, reasonable and nondiscriminatory.” *Public Systems v. FERC*, 606 F.2d 973, 979, n.27 (D.C. Cir. 1979). “[T]he prevailing price in the marketplace cannot be the final measure of ‘just and reasonable’ rates mandated by the Act.” *FPC v. Texaco, Inc.*, 417 U.S. 380, 397 (1974).

Courts have stated that to be “just and reasonable,” rates must fall within a “zone of reasonableness” where they are neither “less than compensatory” to producers nor “excessive” to consumers. When the inquiry is on whether the rate is reasonable to a producer, the underlying focus of concern is on the question of whether it is high enough to both maintain the producer’s credit and attract capital. When the inquiry is whether a given rate is just and reasonable to the consumer, the underlying concern is whether it is low enough so that exploitation by the regulated business is prevented. *Farmers Union Central Exchange v. FERC*, 734 F.2d 1486, 1502 (D.C. Cir. 1984), citing *City of Chicago v. FPC*, 458 F.2d 731, 750-51 (D.C. Cir. 1971, cert. den. 405 U.S. 1074 (1974)).

While FERC has discretion in ratemaking methods, the burden is on the Commission to justify departures from cost-based rates. See *City of Chicago, supra*, 458 F.2d at 749 (a heavy burden is imposed on the Commission to justify departures from cost-based ratemaking). Rates must fall within a “zone of reasonableness” which is “bounded at one end by the investor interest against confiscation and at the other by the consumer interest against exorbitant rates.”⁷ As the Commission has recognized, FERC must justify departures from cost-based rulemaking under

⁷. *Jersey Central Power & Light Co. v. FERC*, 810 F.2d 1168, 1177 (D.C. Cir. 1987).

this just and reasonable standard: “Each deviation, however, must be found not to be unreasonable and to be consistent with the Commission’s statutory responsibility.”⁸

“[W]hen there is a competitive market the FERC may rely upon market-based prices . . . to assure a ‘just and reasonable’ result.” *Elizabethtown Gas Co. v. FERC*, 10 F.3d 866, 870-71 (D.C. Cir. 1993). “*In a competitive market, where neither buyer nor seller has significant market power, it is rational to assume that the terms of their voluntary exchange are reasonable, and specifically to infer that the price is close to marginal cost, such that the seller makes only a normal return on its investment.*” *Tejas Power Corp. v. FERC*, 908 F.2d 998, 1004 (D.C. Cir. 1990) (emphasis added).

FERC has the flexibility to allow market-based rates *if it is assured that the result is just and reasonable rates, e.g., because market power does not exist or had been mitigated.* In *Farmers Union*, 734 F.2d 1502, the court rejected the Commission’s reliance on a cost-based cap for oil transportation rates, because the cap was set at a level designed merely to prevent “egregious exploitation and gross abuse” rather than to ensure a just and reasonable rate. Although premised on an assumption that competition would keep prices in the “zone of reasonableness,” the Commission made no findings that competition for oil transportation services was in fact sufficient to do so. The Commission did not look at market share or otherwise assess the number of competitors available to provide transportation service.

Similarly, in *Tejas Power*, the court rejected a gas inventory charge (“GIC”) that deviated from the cost-based model then in place for natural gas pipeline regulation. The court held that the Commission had erred in accepting the rate as part of a larger settlement package, having

⁸ See *Public Service Company of Indiana, Inc.*, 51 FERC ¶ 61,367 (1990).

made no prior finding that the pipeline lacked significant market power vis-à-vis the customers. 908 F.2d at 1004.

FERC may implement a market-based rate regime only if it has made the appropriate analysis and findings. In *Elizabethtown Gas Co. v. FERC*, the D.C. Circuit upheld a market-based rate for the sale of natural gas because it found the market was competitive:

[W]e have indicated that when there is a competitive market the FERC may rely upon market-based prices in lieu of cost-of-service regulation to assure a “just and reasonable” result. *See Tejas Power*, 908 F.2d [at] 1004 (“*in a competitive market, where neither buyer nor seller has significant market power, it is rational to assume that the terms of their voluntary exchange are reasonable, and specifically to infer that the price is close to marginal cost, such that the seller makes only a normal return on its investment*”). *See also Farmers Union*, 734 F.2d [at] 1510.

Here the Commission specifically found that “Transco’s markets are sufficiently competitive to preclude it from exercising significant market power in its merchant function

In *Louisiana Energy and Power Authority v. FERC*, 141 F.3d 364 (D.C. Cir. 1998), the court rejected arguments by a municipal utility claiming that the grant of market-based rate authority to its competitor would allow the competitor to engage in predatory pricing. In so doing, the court relied on the Commission’s prediction that its new open access transmission policies would prevent such an outcome and that competition and consumer welfare would be enhanced if the competitor were authorized to sell at market-based rates. 141 F.3d at 370. “[S]hould the Commission’s sanguine predictions about market conduct prove incorrect, LEPA can file a new complaint for any abuses of market power that do occur.”

FERC can meet the zone of reasonableness test if and only if the Commission is satisfied that the seller does not possess market power in any relevant market and cannot “significantly influence price in the market by withholding service and excluding competitors for a significant

period of time.” *Citizens Power & Light Co.*, 48 FERC ¶ 61,210 (1989). Only if market power does not exist will market forces drive prices towards marginal cost such that the seller makes only a normal return on its investment.⁹ Only if FERC finds that market power cannot be exercised can it find that the seller’s rates are just and reasonable. Thus, when the Commission authorizes market-based rates, it is under a continuing duty to ensure that the relevant market remains sufficiently competitive to prevent unjust and unreasonable prices. *Process Gas Consumers v. FERC*, 177 F.3d 995 (D.C. Cir. 1999) (“FERC must remain attuned to the status of the affected market vis-à-vis monopoly and competition.”)). Where markets are not sufficiently competitive to keep prices at reasonable levels, a court is likely to conclude that market-based rates are unlawful.

- d. Order No. 888 Requires Transmission-Owning Utility to Expand Transmission Facilities to Meet Firm Commitments to Avoid Exercises of Market Power; It is a Logical Extension to Impose the Duty to Expand to Non-Firm Commitments Where Necessary to Avoid a Given Utility’s Exercise of Market Power.

FERC recently addressed the circumstances under which a transmission owner can be required to build new transmission in *NEPOOL*, 100 FERC ¶ 61,259 (September 6, 2002) (In this order, FERC explained why the Order No. 888 obligation to build additional facilities does

⁹ As the Commission observed in a gas industry order:

In a competitive industry, market forces drive prices toward the producer’s marginal cost. Where price equals marginal cost, consumers are paying precisely the social cost incurred to produce the last unit of output. If at any time the price is too high, excessive returns will encourage other producers to enter the market, thereby increasing production, lowering prices, and eliminating excessive returns. Similarly, if demand increases, price will rise, encouraging additional production that was not economically viable at the lower price. This process will continue until supply and demand reach equilibrium and price reflects marginal cost. Prices established by competitive market forces are in this way driven toward marginal cost. Such prices send the proper signals to both producers and consumers, leading them to produce and consume the optimal amount of goods and services, and thus ensuring that society makes the most efficient use of its resources.

Ceiling Prices: Old Gas Pricing Structures, Order No. 45, FERC Stats. & Regs. ¶ 30,701 at 30,233 (1986), 51 Fed. Reg. 33,168 (June 18, 1986) (emphasis added).

not apply in unique circumstances such as the Cross Sound merchant transmission project). What is significant is the discussion comparing merchant transmission facilities with vertically-integrated transmission owners who may exercise market power when they refuse to expand transmission facilities (emphasis added).¹⁰

NEPOOL explains that the pro-forma open access tariff of Order No. 888 was the response to the Commission's conclusion that "the key to competitive bulk power markets is opening up transmission services."¹¹ The Commission found that vertically integrated utilities -- "monopoly suppliers to their native load" -- exercised market power through the control of transmission. Because open access places vertically integrated utilities' generation at risk, the Commission reasoned, the "utilities have an incentive to deny access by . . . offering transmission services inferior to those used by the transmission owner."

...

NEPOOL contends that it is evident that the obligation to expand was not directed to merchant transmission owners. First, the predicate for the obligation to expand long predates the existence of merchant transmission. Indeed, the Commission's finding of undue discrimination -- to which the obligation to expand is addressed -- was directed at traditional vertically integrated utilities... Unlike a traditional utility, CSC LLC has no generation, no service territory, no native load, no obligation to serve or concomitant right to recover a revenue requirement, and finally, no right of condemnation associated with any transmission expansion. *Unlike a traditional utility whose obligation to expand to serve wholesale transmission customers is comparable to its obligation to expand as necessary to serve native load, CSC LLC has no obligation to native load. Accordingly, NEPOOL contends that the principles of comparability do not warrant an obligation by CSC LLC to expand to serve wholesale transmission customers.*

Second, NEPOOL states that *the open access tariff was intended to mitigate monopoly utilities' potential exercise of market power. CSC LLC is not a monopoly and has no ability to exercise market power as an owner of CSC.* Further, NEPOOL argues, the reason the Commission authorized CSC LLC to sell CSC transmission rights at negotiated rates, rather than regulated rates, was because CSC LLC was not in a position to exercise market power. Even if all CSC capacity were to be withheld (which would not be allowed under the OASIS

¹⁰ With respect to merchant transmission power, FERC issued a notice on November 26, 2002 in Docket RM01-12-000 inviting comment on whether merchant transmission should have an obligation to expand.

¹¹ Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, FERC Stats. & Regs. ¶ 32,514, at 33,049 (1995) ("Open Access NOPR").

posting requirements from the Commission's June 2000 Order), that would not denigrate the competitive status quo ante. As a result, NEPOOL contends, there is no purpose served in directing an obligation to expand to the CSC.

Thus, the OATT imposes a duty to expand transmission for firm transmission customers on the conventional IOU subject to compensation. *See* Order No. 888 final rule, 61 Fed. Reg. 20,540 (1996), Tariff provisions §§ 13.5, 15.4 and 27. The OATT establishes the principle that a duty to build facilities may be necessary to redress market power, although the OATT is limited to "firm" transactions.

e. Expansion of Transmission Facilities Should Also be Ordered Under the Market Power Mitigation Features of the SMD Rulemaking.

FERC bases its SMD NOPR and its new Network Access Service tariff on a need "to remedy undue discrimination, enhance competition, remove economic inefficiencies and ensure just and reasonable rates, terms and conditions of transmission of electric energy..." SMD NOPR ¶ 6.

The SMD NOPR at Paragraph 434 provides that the Market Monitor's work "must be integrated into the regional planning process. The market monitor's analysis of the markets will help identify load pockets and can help provide direction for needed investment in generation, including distributed generation, demand response capability *and transmission infrastructure to improve the competitive structure of markets.*" (Emphasis added.)

Despite the recognition that transmission infrastructure may bear on market power, the market power mitigation provisions of the NOPR are limited to measures related to generation market power such as must run units and bid caps. While these measures are much needed to address other incidents of market power, the SMD NOPR does not go far enough to address market power caused by transmission constraints which vertically-owned utilities have no

incentive to resolve. FERC can and should utilize its Section 206 authority to put teeth into the requirement that RTOs and ITPs require implementation of *compensated* transmission enhancements where necessary to mitigate market power.

f. The Essential Facilities Doctrine Provides Support for the Relief Requested Herein.

A recent decision, *Covad Communications v. BellSouth Corp.*, 299 F.3d 1272 (11th Cir. 2002) is instructive. Covad is a seller of high-speed Digital Subscriber Line (“DSL”) internet service (dial-up Internet access). BellSouth is a regional telephone service and telecommunications provider, which also sells DSL service. Covad and BellSouth entered into an “interconnection agreement” to allow Covad to provide DSL service to consumers over BellSouth’s existing telephone lines. To bring its services to consumers in BellSouth’s region, Covad must have dependable, timely, and affordable access to the local telephone network controlled by BellSouth. The local telephone network facilities controlled by BellSouth cannot practicably be duplicated. Thus, to operate feasibly, Covad must be able to “interconnect” its DSL network with BellSouth’s local telephone network, which means, at its most basic, that Covad needs to be able to connect its wires to the BellSouth wires that make up the local telephone network. Covad’s complaint alleged that BellSouth frustrated its competitor’s access to the essential facility it controlled by denying Covad access on the basis that space was inadequate:

In this suit, Covad alleges that BellSouth aimed to stifle competition and protect and extend its local telephone monopoly, in violation of the Interconnection Agreement and the antitrust laws, by embarking on a series of dilatory, anticompetitive acts designed to prevent or delay Covad’s entry into the DSL market, impede its ability to deliver service to consumers, and drive Covad from the marketplace. In particular, Covad alleges that BellSouth regularly misrepresented the availability of space in BellSouth’s central offices so as initially to effectively deny collocation altogether.

Id. at 1277. Similarly, BellSouth “strategically understaffed its wholesale division” which “slowed down order processing and created backlogs.” Conrad alleged:

By refusing to develop adequate systems for placing wholesale orders, BellSouth thwarted Covad’s aggressive first-to-market strategy, caused Covad to lose customers, impeded Covad’s ability to deliver high quality service, and protected BellSouth’s monopoly.

The court denied BellSouth’s motion to dismiss, on the basis that Covad had stated sufficient facts to state a claim under the Sherman Act. The court observed:

Covad complains that BellSouth denied Covad the use of an “essential facility,” namely its network of telephone lines. Although, as Covad recognizes, the antitrust laws in general do not require that firms (including monopolies) affirmatively help their competitors to succeed, there is a narrow exception to this general rule when a monopolist improperly withholds access to an “essential facility” without which a competitor cannot enter or compete in a market. *See, e.g., Consolidated Gas Co. of Fla., Inc. v. City Gas Co. of Fla.*, 880 F.2d 297, 301 (11th Cir. 1989) (hereinafter, “Consolidated Gas I”).

Id. at 1284. The court found that monopoly leveraging could occur if BellSouth, which at present has no monopoly in the high-speed internet market “used its monopoly in the communications market by refusal to deal with or provide essential facilities to competitors in the high-speed internet market.” *Id.* at 1284. Monopoly leveraging can violate the Sherman Act, § 2.

The court explained the Essential Facilities Doctrine as follows:

The withholding of access to an essential facility without which a competitor cannot enter or compete in a market is a violation of the antitrust laws. *See Consolidated Gas I*, 880 F.2d at 301. Under the well-established “essential facilities” doctrine, an inference of anticompetitive intent in violation of Section 2 arises upon a showing of four elements: (1) control the essential facility by a monopolist; (2) a competitor’s inability practically or reasonably to duplicate the essential facility; (3) the denial of the use of the facility to a competitor; and (4) the feasibility of providing the facility. *See MCI Communications Corp. v. AT&T*, 708 F.2d 1081, 1132-33 (7th Cir. 1983). By exercising its control over an

essential facility (sometimes called a “bottleneck”) to withhold access to that facility, a monopolist can exclude competition. For example, in *Consolidated Gas I*, we found that a massive system of natural gas pipes controlled by the defendant was an essential facility. Control over that bottleneck, the gas pipelines, enabled the defendant to exercise its power in the market to exclude competition. *See Consolidated Gas I*, 880 F.2d at 301. “Thus, the antitrust laws have imposed on firms controlling an essential facility the obligation to make the facility available on non-discriminatory terms.” *MCI*, 708 F.2d at 1132.

Id. at 1285.¹²

BellSouth argued that the essential Facilities Doctrine imposes no duty on the monopolists to build. The court found that Covad’s allegations were sufficient to state a claim whether or not it could ultimately prove a violation:

... BellSouth argues that Covad is attempting to use antitrust law not merely to gain access to facilities, but also to force BellSouth to construct new facilities or to alter the nature of its business and become a renter of facilities for competitors to use. BellSouth observes that “no case has suggested that the monopolist must build new capacity to satisfy a would-be sharer...” BellSouth characterizes Covad’s claim as an attempt to harness the antitrust law to force BellSouth to build new facilities, to develop new software, or to modify existing facilities quickly enough to meet Covad’s alleged business needs.

For the most part, these are arguments that must be addressed at a later stage of the proceedings, such as summary judgment or trial. We note that with regard to BellSouth’s first point, Section 2 prohibits denial of access to essential facilities on reasonable terms. *See Alaska Airlines, Inc. v. United Airlines, Inc.*,

¹² Covad relied on *MCI* because its facts were similar:

In *MCI*, 708 F.2d at 1133, the Seventh Circuit held that the local telephone network was an essential facility and that AT&T could not deny *MCI* reasonable access to it. Covad argues that *MCI* is essentially indistinguishable from the present case, and uses it as a template in stating the elements of its essential facilities claim. First, Covad alleges that BellSouth controls an essential facility, indeed, the same essential facility (local telephone exchange) at issue in *MCI*. *See id.* Second, Covad alleges that it would not be economically feasible “to duplicate Bell’s local distribution facilities (involving millions of miles of cable and line to individual homes and businesses), and regulatory authorization could not be obtained for such an uneconomical duplication.” *Id.* Third, Covad contends that BellSouth denied interconnections to the essential facilities, and fourth, did so even though the interconnections could have been feasibly provided. *See id.* Finally, Covad maintains that BellSouth’s conduct was intended to, and did, leverage BellSouth’s local exchange monopoly into the local internet access markets to exclude Covad and to create or preserve BellSouth’s monopoly power in the local internet access markets.

Id. at 1285-86.

948 F.2d 536, 542 (9th Cir. 1991); *City of Vernon*, 955 F.2d at 1367; *Laurel Sand & Gravel, Inc. v. CSX Transp., Inc.*, 924 F.2d 539, 545 (4th Cir. 1991); accord *Del. & Hudson Ry. V. Consol. Rail Corp.*, 902 F.2d 174, 179-80 (2d Cir. 1990) (“it is sufficient if the terms of the offer to deal are unreasonable”). The “applicable legal standard” is that “any company which controls an ‘essential facility’ or a ‘strategic bottleneck’ in the market violates the antitrust laws if it fails to make access to that facility available to its competitors on fair and reasonable terms that do not disadvantage them.” *United States v. AT&T*, 524 F. Supp. 1336, 1352-53 (D.D.C. 1981) ... Whether or not Covad can ultimately prove a violation, its complaint does allege that BellSouth sometimes denied access to its facilities outright and other times denied access on reasonable terms.

Id. at 1286-87.

Industrial Consumers do not argue that in every instance a transmission monopolist’s refusal to upgrade transmission facilities is inevitably an example of monopoly leveraging or a violation of the Sherman Act. However, denial of access to essential facilities on reasonable terms raises serious competitive concerns and justifies FERC scrutiny to assure itself that the conduct is not anticompetitive and an abuse of market power.

Thus, FERC has the authority and duty under Sections 205 and 206 of the FPA to revoke market-based rate authority where generation or transmission market power threatens achievement of just and reasonable, non-discriminatory rates. In its Market-based Rates Investigation docket (EL01-118-000), FERC proposed to revise market-based rate approvals prospectively to incorporate a condition allowing FERC to revoke market-based rate authority and/or impose refund obligations if the Commission found economic or physical withholding of supply. The same logic would apply if, on a case-by-case basis, FERC finds that a given utility in an exercise of market power has failed to provide reasonable transmission access to competitors through unreasonable refusal to expand facilities. Transmission is the paradigmatic essential facility and deliberate under-building can result in withholding and discrimination against competitors.

In addition or alternatively, in the SMD rule, FERC could require that ITPs or RTOs address market power abuse by ordering compensated transmission expansion where it is necessary and cost-effective to relieve congestion. In the SMD NOPR, FERC recognized that transmission congestion may reflect exercise of market power. The concern that FERC has correctly identified is not addressed by the market power mitigation proposal in the SMD NOPR which should be expanded. Where market power is found to exist due to constrained transmission facilities, the RTO or the ITP could be charged with requiring a demonstration of best efforts/due diligence by transmission owners to relieve the constraint.

C. Industrial Consumers Encourage State Regulators to Actively Participate in Each ITP or RTO’s Stakeholder Process. (¶¶ 551-555)

The NOPR would require each ITP to have a Regional State Advisory Committee (RSAC). The RSAC would be formed and have direct contact with the ITP board “in a manner which recognizes its public interest responsibilities, and be designed to provide the board as well as market participants and the Commission with a consensus view from states in the area.” Each region will decide how to form its RSAC and FERC seeks public comments on how RSAC members should be selected.

RSACs are expected to work with RTOs or ITPs “to seek regional solutions to issues that may fall under federal, state, or shared jurisdiction.” These issues include: (1) resource adequacy requirements, (2) transmission planning and expansion, (3) rate design and revenue requirements, (4) market power and market monitoring, (5) demand response and load management, (6) distributed generation and interconnection policies, (7) energy efficiency and environmental issues, and (8) RTO management and budget review.

The NOPR identifies “rate design and revenue requirements” as issues that RSACs can bring “a valuable regional perspective” and “play a role in deciding these issues in partnership with the Commission.” Once RSACs are established, FERC intends to work with them to “establish protocols for deciding these regional rate issues.”

Industrial Consumers are concerned that this proposal creates a potential new layer of regulation. The open-ended charge and regional discretion given to these committees creates the potential for state or local interference in interstate electricity markets that would nullify the noble objectives of Standard Market Design. Industrial Consumers do not oppose a strong role for states in the affairs of ITPs, but that role should be at the table with other stakeholders in each ITP’s stakeholder process. We see no evidence from the experience of ISOs that such a role does not provide adequate representation of state interests.¹³ States that seek a stronger voice in the RTO or ITP process should do so by becoming voting members of the stakeholder advisory committee. Should they elect that venue, they should be included in a sector reserved for public interest groups—not with end users.

D. Resource Adequacy and Forward Contracting are Important Federal Policy Objectives, But the Breadth and Scope of the NOPR Proposal is Unnecessary and Needlessly Complicated. (¶¶ 457-550)

1. Industrial Consumers Support the NOPR’s Conclusion That the Installed Capacity (ICAP) Requirement Should Not be Imposed as a National Standard. (¶ 483)

The LMP-based standard market design adopts the energy-only dispatch methodology from the old industry regime. Under traditional cost of service, the utility’s fixed costs were separately recovered in some form of explicit or implicit demand charge. But fixed cost

¹³ For example, the states within the footprint of PJM have executed a Memorandum of Understanding with PJM that establishes the working relationship between the state commissions and the ISO.

recovery in the transition to a more competitive market paradigm has been problematic in the Northeast and elsewhere (¶ 483). For a number of reasons, liquid forward markets have not emerged.¹⁴ The trading practices of merchant generators, including utility-owned generators with market-based rate authority, tend to favor the bidding of generation into the short-term spot markets and relying on intermittent “scarcity rents” to recover the capital costs of the assets.¹⁵ But the potential for politically unpopular price spikes forced the Commission to impose bid-caps in all the bid-based markets making it difficult for some generators (but not all) to fully recover their fixed costs.¹⁶ The installed capacity (ICAP) requirement was subsequently established with the intent of ensuring generation resource adequacy. The NOPR describes the flawed results of the ICAP markets in the Northeast (¶¶ 483, 527 and 536), and correctly rejects the application of ICAP as a national requirement (¶ 483).

2. Industrial Consumers Believe that Requiring ITPs to Ensure Sufficient Resource Adequacy as Prescribed in the NOPR is Unnecessarily Expansive and Beyond the Bounds of the Commission’s Statutory Authority. (¶¶ 457-550)

As proposed in the NOPR, ITPs must complete an annual demand forecast for their areas and then assess whether the collective resource plans of load-serving entities are adequate to meet projected future needs. *Id.* ¶ 489. The level of reserves would be set by regional state advisory committees. *Id.* ¶ 492. The ITP must determine if each LSE’s planned resources meet certain minimum standards and satisfy the entity’s share of the regional resource requirement.

¹⁴ Industrial Consumers do not consider the large volume of transitional vesting contracts such as state-mandated Provider of Last Resort (POLR) contracts as a valid measure of the amount of bilateral contracting that is taking place in the forward markets of existing ISOs.

¹⁵ The combination of a uniform-price auction that clears the bid-based markets and the absence of any meaningful price elasticity in the form of demand response contribute to this skewed market preference.

¹⁶ The generators of incumbent utilities recovered their fixed costs in the form of “competitive transition charges.” Other generators were more than capable of earning a return on, and of their investments within a \$1,000 bid cap.

Id. ¶¶ 509-510. Generation must be owned or under contract to the LSE under conditions such as a shortage. *Id.* ¶ 512. The ITP must be satisfied that the generation is feasible and sufficient transmission is available. The resource adequacy requirement is enforced with either Commission-set tariff penalties or curtailment. *Id.* ¶ 527.

It is a fact that the electric grid is interconnected, for areas outside ERCOT, and that events in one section of the grid impact grid users and consumers elsewhere. This has been highlighted numerous times since the massive black-outs experienced in the Northeast in the mid-1960s. Because the Commission's jurisdiction concerns interstate transmission and the wholesale power market, and because the Commission is charged with ensuring that energy prices in the wholesale power market are "just and reasonable," it appears reasonable that the Commission should impose a limited resource adequacy requirement upon users of the interstate grid. Absent requirements to assure adequate generation supply for firm markets, the industry may again experience chronic price spikes as those experienced in the West in 2000-2001, due primarily to supply shortages. Not to impose resource adequacy requirements would be ignoring the fundamentals upon which sound markets operate and leaves individual utilities and consumers to fend off market dislocations caused, for example, by load-serving entities which may not have adequately planned for dry years in hydro dependent regions. Adequate supply is necessary to mitigate price spikes that will occur during peak demand periods. Because it is politically unacceptable and undesirable to have prolonged price spikes, the Commission must ensure that mechanisms are in place to assure adequate supply for anticipated demand in the wholesale market or for demand impacting the wholesale market to enable prices to float within a "zone of reasonableness" and thereby be determined to be "just and reasonable".

The Commission has already seen the ill effects in California with lack of appropriate planning to meet electricity demand on a portfolio basis and the industry will be attempting to resolve knock-on problems caused by this dilemma for years. However, because the Commission does not have direct jurisdiction over generation supply nor jurisdiction over requirements for retail electricity providers (utilities and retail marketers), the Commission must confine its actions to those tools necessary for the wholesale market. The physical and economic distress in western power markets in 2000 and 2001 form the initial basis for economic assessment for support of any resource adequacy program needed to establish an explanation or adequate record of support for FERC's assertion of such jurisdiction.

Nonetheless, Industrial Consumers strongly believe that if there was a truly liquid and transparent forward market, the market would itself assure resource adequacy. We may not see a truly liquid and transparent forward market for many years if the skewed economic incentives associated with bidding generation into the spot market are not removed. As noted in our November 15, 2002 comments, Industrial Consumers believe that integration of demand response into the markets, vigilant market power mitigation (an essential interim measure until demand response is adequately integrated in the markets) and market monitoring may help correct this problem.

Industrial Consumers have several major concerns with the resource adequacy requirement as defined in the NOPR.

First, the burden of proof of adequacy is on the customers (LSEs and Market-Participating Loads).¹⁷ In some markets, there is no incentive (structural or otherwise) for

¹⁷ In the November 15, 2002 Comments of Industrial Consumers, we proposed a new definition in the SMD Tariff of "Market-Participating Loads," which would include loads that are authorized under state laws and regulations to buy electricity services from competitive suppliers and/or sell demand response. The purpose for this

generators to fairly negotiate the bilateral contracts envisioned by this requirement. If generators can exercise market power in short-term markets, or if they can exercise local market power, they can merely transfer that market power into the forward market. In addition, Industrial Consumers' support for industry restructuring was originally predicated on the desirability of shifting the risk of generation investments into the private capital markets. Under the old regulatory regime, ratepayers often bore all the risk of failed generation projects. We fear that the resource adequacy requirement will tend to restore that risk on native load customers because we fear that LSEs may not prudently comply with this requirement. They may, in fact, over-comply. This possibility could lead to a new round of "stranded" generation investments.

Second, the forward markets that may emerge from the resource adequacy requirement may be distorted by a fixed planning horizon, *e.g.*, three years. It is hard to imagine what unintended consequences might emerge with a quasi-standardized contract term, but the desired outcome in any workably competitive forward market is a mix of contract periods that reflect different degrees of customer and producer risk, new construction lead-times, and the existing resource base. This "mix" is best left to the market and not made an administrative duty of the ITP or RTO.

Third, we are concerned with the risk associated with ostensibly rebundling the industry and creating a new form of vertically integrated utility. The evolution from ISOs, to RTOs, and now to ITPs has produced a proposed entity that is not simply a "transmission provider" but also a market maker, a market monitor, and a resource planner. The NOPR would allow ownership

proposal was to distinguish between LSEs (that are typically distribution utilities) and loads in retail-access states or are otherwise authorized to participate in the wholesale markets.

of transmission assets and even solicits comment on making the ITP a provider of last resort for energy (generation) resources.

Finally, we are concerned with the potential to restore inefficient, central planning-type practices such as Integrated Resource Planning (IRP) and Demand Side Management (DSM). We note in particular that demand response is not DSM, and DSM is not demand response. DSM, as practiced in the 1980s and early 1990s, was regulation at its worse. One class of customers was taxed to subsidize the appliances or process equipment of other customers, under the pretense of promoting energy efficiency. For example, industrial end users that made energy efficiency investments on their own were forced to subsidize investments of their competitors who did not make such investments on the same timely basis. The NOPR's resource adequacy requirement would potentially restore this type of misguided public policy.

3. Industrial Consumers Support Establishing a Forward-Looking Resource Adequacy Requirement On an Interim Basis With a Default Regional Reserve Margin (12%). (¶ 493)

In comments to the Commission before the issuance of the NOPR, Industrial Consumers maintained that inadequate forward contracting resulted from the ease with which the spot markets could be gamed for speculative purposes. We believe that an energy-only market can provide sufficient payments to generators to recover fixed costs but only after a fully functioning market for demand response is in place to prevent the exercise of market power. As an interim measure, Industrial Consumers support the concept of the resource adequacy requirement, including the default regional reserve margin (12%). We support establishing a forward-looking resource adequacy requirement in the form of a new interim Ancillary Service in the SMD Tariff, but recommend stopping short of the prescriptive resource planning requirements envisioned in the SMD NOPR. SMD NOPR ¶ 457-550. Nonetheless, we highly commend the

Commission for recognizing the imbalance between the spot and forward markets, and we applaud the Commission's effort to correct this imbalance by attempting to create an economic incentive for greater forward contracting.

The interim Ancillary Service we propose would likely take the form of a new capacity product that each RTO or ITP would acquire via an auction. The service should meet the following six principles.

First, the requirement should be based on load served as measured at the retail meter at the time of system peak. This approach requires that customers be charged for loads they place on the system as measured at the retail meter, and also requires cost allocations for any such product to be based on actual consumption at the time of system peak. It is essential that such requirements be based on actual usage of the system by customers as measured at the meter (customer interface) and not some fictitious attribution of "phantom load" based on non-jurisdictional events or processes occurring behind the meter.

Second, any new capacity product should not require a forward procurement regime that eliminates the value of real-time demand response. In other words, the capacity product must be structured so as not to disincent customer demand response.

Third, any new capacity product should avoid all aspects of grandfathering incumbent capacity resources. In order to avoid having capacity requirements manipulated by incumbents to bar entry into the market and inhibit retail access, FERC must assure that new entrants are not disadvantaged by discriminatory "deliverability" requirements that, through a vintage process,

exclude new capacity resources from competing with incumbents for use of the existing transmission system.¹⁸

Fourth, capacity payments should not “double recover” capacity cost already incorporated in energy prices.

Fifth, a capacity product should never be structured to guarantee the recovery of costs.

And finally, a capacity product should be based on a regional reserve requirement that takes into account the economic cost of various levels of reliability when setting reserve margins. Reliability must not be maintained at any cost.

4. Industrial Consumers Recommend that the ITP Conduct a Simple Auction for the Amount of Resources Needed to Meet the Default Regional Reserve Margin. (§§ 494-519)

Industrial Consumers recommend that the *interim* resource adequacy requirement focus exclusively on the ITP’s requirement to preserve short-term reliability on a forward-looking basis over some reasonable planning horizon. The ITP would generally assess each LSE’s coverage of its share of a regional reserve margin, while at the same time recognizing the benefits of load and resource diversity in reliability management. The regional reserve margin is a public good and its cost should be socialized in the SMD Tariff as a new form of interim Ancillary Service (*e.g.*, Forward Reserves).

This approach need not be a complex, administrative task. Should the ITP determine that a shortage may develop during its planning horizon, the ITP should conduct a competitive auction for the amount of resources needed to meet the regional reserve margin. The NOPR’s

¹⁸ We note that in PJM, such requirements were used to effectively curb retail competition because incumbent suppliers of ICAP were successful in promoting the myth that only their electrons were deliverable and not those of their electrically identical competitors. This enabled the incumbent suppliers to corner the ICAP market and drove up costs for loads served by competitive suppliers.

approach could easily result in too much generation. Industrial Consumers oppose the need for complex audits, resource standards and other trappings of command-and-control regulation that are suggested in the NOPR.

E. Industrial Consumers Support the Allocation of the Value of the Transmission System Exclusively to LSEs and Market-Participating Loads by Either Direct Assignment or Auction. In Either Case, the Value of the Transmission System Should Always “Follow the Load.” (¶¶ 376-382)

The NOPR proposes to either directly assign Congestion Revenue Rights (CRRs) to customers that currently have the receipt and delivery points identified in their existing contracts (“actual or implicit”), or current customers would be given the auction revenues from the sale of CRRs. The NOPR expresses a preference for auctions, but proposes that “regions” be given flexibility in setting the initial terms for CRRs sold in auctions. During an initial transition period of four years, the NOPR proposes that regions also be allowed to decide to directly assign CRRs. At the end of the transition period, the ITP would be required to submit a filing to move to an auction for CRRs with the auction revenues allocated to those customers that pay the access charges. The ITP may justify why a longer transition period is necessary.

Industrial Consumers are concerned that if the market value of the transmission system—as represented by CRRs—is separated from end-use customers who ultimately pay for the transmission system, some market participants will unduly profit at the expense of consumers by using CRRs to game their bids and generation dispatch and not for their intended purpose which is to hedge. We are also concerned that if there is not a sufficient amount of CRRs available in the market, end-use customers (or their suppliers) may not be able to hedge their transactions against congestion, and power markets will remain unnecessarily unstable and potentially face

future reliability problems. These concerns form the basis for our position on the allocation of CRRs by either direct assignment or auction.

Industrial Consumers support the direct assignment of CRRs in some reasonably short transition period to LSEs and all Market-Participating Loads (MPLs). Auctions should be delayed until LSEs and MPLs have some experience with the new market mechanics and some understanding of the innate value of the CRRs that they hold. We believe that CRRs or the market value of CRRs as determined by auction should be allocated directly to end-use customers based on the historic use of the transmission system by their historic supplier.

Industrial Customers also recommend that the Commission not permit any entities other than LSEs and MPLs (or their agents) to hold CRRs or participate in auctions until such time there has been a determination by the Commission that such other entities—*e.g.*, generators or ITCs—lack market power such that they cannot abuse the congestion management system through the ownership of CRRs.¹⁹ CRRs will be scarce even under the best of circumstances.²⁰ Therefore it is not sound public policy to allow CRR ownership for the purpose of gaming the dispatch process.

Industrial Consumers believe that the Commission has an obligation to ensure reliable and reasonably stable competitive markets. Therefore, it is vital that the transition to and allocation of CRRs support a liquid and transparent forward market for transmission rights that ultimately reaches out to the horizon of new generation and transmission construction. The forward locational price discovery necessary to provide the “lead compensation” necessary to

¹⁹ CRRs are the “rights” of end-use customers who have paid for the transmission system. LSEs do not have comparable rights to CRRs. Instead, CRRs that are allocated to LSEs (or the value of the CRRs as determined by auction) are only held in trust by the LSEs. LSEs have no claim to CRRs other than as trustee for native loads.

²⁰ This results, in part, from the simultaneous feasibility requirement, and, in part, from chronic public opposition to new or expanded transmission corridors.

make markets stable can only be derived from the forward trading of CRRs to hedge expected LMP charges, not the LMP charges themselves.²¹

To ensure reasonably stable markets and the ability of consumers to adequately hedge themselves against LMP congestion charges, a sufficient number of CRRs must be available to the market by auction or in the secondary markets. This means that ultimately all allocated CRRs must be auctioned and the market value of those CRRs must be allocated rather than the CRRs themselves. It also means in those regions where a substantial amount of the total CRRs have been allocated, a move to mandatory auctions (*i.e.*, the allocation of the value of CRRs rather than the CRRs themselves) will need to happen sooner rather than later. Moreover, in such situations, an allocation of CRRs rather than the value of CRRs will be an impediment to retail access as it will be difficult for end-use customers (or their suppliers) to obtain the CRRs required to fully hedge their transactions against LMP charges.

Industrial Customers are concerned that the delay towards moving to allocating the revenues from the allocated CRRs, rather than the CRRs themselves, will undermine the liquidity in the market for CRRs such that LSEs and MPLs will not be able to obtain sufficient CRRs from either the ITP or the secondary market to adequately hedge their bilateral transactions against congestion charges. CRRs may be allocated on a *pro rata* basis based on the incumbent utility's historical usage of the transmission system to serve its native load. Release of these CRRs to LSEs or MPLs on a load ratio share basis will provide the value of the

²¹ By "lead compensation," we mean the locational forward price discovery provided by a liquid and transparent forward market for transmission rights. This provides an advance signal to the market on the need for new generation and transmission construction that compensates for the lag associated with the lead time for that construction. This works to improve the precision of meeting the infrastructure needs of consumers while reducing the response time of the market to those needs. It is analogous to the term "lead compensation" as it is used in linear control system theory where such "lead compensation" improves steady-state accuracy and significantly reduces settling time. Settling time is the time required for the output of a control system to first reach and thereafter remain within a prescribed percentage of its final value. A control system with a shorter settling time more quickly responds to a required adjustment and more quickly stops oscillating around the final adjusted output.

transmission system for which transmission customers have historically paid, but it will not necessarily provide them with CRRs that are useful to hedge bilateral transactions against congestion charges and the incumbent may still have locked-up the lion's share of the CRRs. By only allocating the value of the allocated CRRs as determined in the ITP auction, rather than the CRRs themselves, LSEs and MPLs will be able to receive the value of the transmission system while still being able to acquire the specific CRRs they need to hedge their bilateral transactions against congestion charges. The Commission should require that the auction revenues from allocated CRRs, rather than the CRRs themselves, be awarded to LSEs and MPLs where retail access has been introduced.

II. Responses of Industrial Consumers to the Commission's Direct Questions or Requests for Comments on Selected Issues and Alternatives.

Inter-Regional Transfers

Paragraph 186. The Commission proposes that as long as transmission owners have an opportunity to recover their embedded costs—to increase competition—the Commission intends to prevent customers from being assessed multiple transmission charges (“rate pancakes”). The Commission proposes to create a mechanism that recognizes the import/export quantities in establishing the revenue requirement to be recovered through the access charge. The NOPR seeks comment on two approaches that could be used. One method would be to have the "source" Independent Transmission Provider allocate a portion of its revenue requirement to the "sink" ITP's transmission customers. An ITP's revenue requirement could be reduced by the amount of revenues associated with through-and-out service and that portion of the revenue requirement would then be included as uplift in the scheduling charge paid by all customers of the sink ITP in whose service area the power sinks. Under this approach, costs would not be

shifted from the beneficiaries of the inter-regional transaction to the load on the source side of the transaction.

Paragraph 187. Alternatively, under a revenue crediting approach, inter-regional transfers could be priced at the load ratio share charge (or a similar transmission charge) and the inter-regional transaction charges would be netted out over some time period (*e.g.*, one month or one year). This method would assign the inter-regional charges to all customers within the sink ITP.

Response of Industrial Consumers:

The Commission seeks comment on two different ways to provide a mechanism that recognizes the import/export quantities in establishing the revenue requirement to be recovered through the proposed SMD access charge. The Commission's motivation to provide a mechanism appears to be driven by a desire to avoid the transfer of embedded cost charges from through-and-out transmission customers to LSE transmission customers with the removal of rate pancaking. The Commission also appears to be adopting a policy of "participant funding" for new, non-reliability related, transmission expansion when an ITP has a regional planning process in place. Under the Commission's proposal, transmission expansion related to through-and-out transmission service would not be rolled into embedded costs.

If the Commission adopts or allows a participant funding proposal for transmission pricing, the Commission should only consider providing a mechanism to recognize import/export quantities in establishing revenue requirements on a transitional basis. Under participant funding, transmission expansion to support through-and-out service would not be rolled into embedded costs unless there were bona fide system benefits whereby a portion of the costs may be legitimately rolled-in. Therefore, there is only an issue of legacy costs and the impact of cost

shifts to mitigate. The Commission should transition out the mechanism over a period of no more than five years.

In regard to the choice of mechanism, the Commission proposed to either (i) allocate a portion of the revenue requirement of the “source” ITP to the revenue requirement of the “sink” ITP or (ii) apply a load ratio charge share for inter-regional transfers that would be paid for by net importing transmission customers of a net importing ITP. Unfortunately, neither approach is satisfactory. The first approach fails to recognize that intervening ITPs on the contract path between the source and sink ITP were also formerly receiving revenues that were being applied against its revenue requirement. In addition, the first proposal fails to recognize that all ITPs who experienced a portion of the actual flow of power from source to sink were adversely affected and likely experienced an increase in embedded transmission costs due to the transaction. Therefore, the Commission should find the first proposed mechanism unsatisfactory.

The second proposed mechanism is not satisfactory either. It too perpetuates the contract path fiction and fails to recognize that all ITPs that experienced a portion of the actual power flow from source to sink likely saw an increase in embedded transmission costs due to the transaction. Moreover, the second proposal would defeat the goal of the Commission to not discourage access to long-distance competitors. Under the second proposal, transmission customers are penalized with higher scheduling charges for importing power from outside the ITP’s transmission system.

Instead of adopting either of the two proposed mechanisms, the Commission should instead adopt a variation of the first proposal under which instead of just allocating a portion of the “source” ITP revenue requirement to the “sink” ITP, a portion of the revenue requirement of

each and every ITP experiencing flow from the transaction from source to sink would be allocated to the “sink” ITP in proportion to the amount of power flowing over each ITP system and the amount of miles of transmission facilities on each ITP system appropriately weighted to reflect the cost of transformers, phase shifters and other costly non-wires transmission facilities. This would appropriately line up legacy transmission costs with those parties that caused them. However, the Commission should only adopt this mechanism on a transitional basis unless it chooses to roll-in transmission expansion rather than adopt participant funding for transmission expansion.

Paragraph 188. The NOPR seeks comment on whether there should be a uniform cost allocation of inter-regional costs among all zones within an ITP's system.

Response of Industrial Consumers:

The inter-regional costs should be allocated using the flow-based mechanism we recommended above. If the ITP is using postage stamp pricing, the sink should be considered to be the entire ITP system and the costs should be uplifted to all ITP loads. If an ITP is using license plate pricing, the sink should be considered on a zone-by-zone basis within the ITP and costs should be uplifted to ITP loads in the specific zones that are causing inter-regional costs via the recommended flow-based revenue requirement allocation mechanism.

Paragraph 189. The proposed rule advocates treating inter- and intra-regional transmission pricing the same. As explained elsewhere, customers within the region who pay the access charge will be entitled to CRRs or the revenues from the auction of those rights. The Commission proposes a similar result for inter-regional transactions when customers in one region are paying a portion of the embedded costs of another region. The NOPR seeks comment on how to assign CRRs to the customers of the importing region.

Response of Industrial Consumers:

With the removal of rate pancaking coupled with the revenue requirements sharing between ITPs on an aggregate actual flow basis as we have proposed above, CRRs should be allocated from source to sink across to each LSE and MPL for all ITP systems involved in transmission of the LSE's historical transactions. The Commission's proposed SMD relies on LMP that works on actual flow principles rather than contract path principles. CRRs that would be allocated from source to sink need to be evaluated in a coordinated fashion by all affected ITPs, and if the proposed CRR passes the simultaneous feasibility test, CRRs should be awarded to the LSE or MPL as necessary on each ITP system. Otherwise, the LSE or MPL will effectively be subjected to rate pancaking as it will be allocated CRRs only in its sink ITP and would have to purchase CRRs on other ITP systems in the secondary market if it chose to supply its load from resources located outside the sink ITP's transmission system. This conflicts with the Commission goal of not discouraging access to distant competitors.

Application of Inter-Regional Pricing to Parallel Path Flows

Paragraph 190. To the extent the Commission adopts a true-up methodology for recovering the costs of through-and-out services, should a similar pricing methodology be applied to parallel path flows? Parallel path flows are comparable in that one region benefits by the use of a neighboring region's transmission facilities. Parallel path flows are currently resolved through cooperation. An alternative method would be to price all uses of the grid. The NOPR seeks comment as to how cost impacts of parallel path flows across regional borders should be addressed.

Response of Industrial Consumers:

The cost impact of parallel flows across regions can be addressed using the actual flow based revenue sharing mechanism we have proposed above. Under the mechanism the revenue requirements of each ITP are shared based on the aggregate flow of transactions over those systems. If participant funding is not adopted this revenue sharing mechanism could be used on a permanent basis. If participant funding is implemented in the future, participant funding will inherently handle parallel flow impacts, provided expansions are evaluated on a source to sink basis and all affected ITPs coordinate the evaluation of any proposed expansion to ensure CRRs are allocated in a coordinated fashion.

Pricing of New Transmission Capacity

Paragraph 202. The Commission has established as a goal the removal of any cost recovery impediments to transmission expansion so that needed upgrades get built. To that end, the Commission states in the NOPR that its preference is to allow recovery of the costs of expansion through participant funding, *i.e.*, “those who benefit from a particular project (such as a generator building to export power or load building to reduce congestion) pay for it.” In the Generation Interconnection proposed rule, the Commission introduced the idea that participant funding may be an acceptable pricing policy where an independent entity determines: (1) the cost of and responsibility for needed upgrades; (2) congestion price signals to which the customer responds (along with CRRs); and (3) the assumptions underlying the power flow analysis. The Commission envisions that, under the SMD, the ITP will perform all of these functions, which will allow the Commission to consider the use of participant funding. Accordingly, the NOPR proposes that for transmission upgrades included in a regional planning process conducted by an independent entity such as an ISO or RTO, the Commission will consider participant funding for

that project. Otherwise, in the absence of independence, a default pricing policy will apply. Under the default pricing policy, all high voltage network upgrades of 138kV and above will be rolled-in. The NOPR also proposes to assign a portion of embedded costs to distant beneficiaries in the form of an interregional transmission service pricing mechanism. Through this mechanism, cost would be allocated to the region that benefits from the expansion, which may not be the same region in which the expansion facilities are located.

The NOPR seeks comment whether these pricing proposals are appropriate to meet our goal of expediting needed infrastructure investment or whether another method would be more effective.

Response of Industrial Consumers:

Most transmission upgrades can be characterized by their investment “lumpiness.” This characteristic makes it difficult to apply a strict form of participant funding that essentially assigns the investment costs to a limited set of market participants. Generally, Industrial Consumers support rolled-in rate treatment of new transmission investment unless a compelling case is made for other treatment. Proposing that an independent entity such as an RTO or ITP make this determination is an essential step and we strongly support this proposal. Other features in the NOPR’s transmission pricing proposals may contribute to the convergence of rolled-in treatment with participant funding, provided cost causation principles are consistently applied. This is a very desirable outcome and we urge the Commission to pursue it. The interregional transmission service pricing proposal helps accomplish this outcome and we also support this pricing proposal because it eliminates a potential source of transmission “free-riders” by expanding the regional coverage of embedded rates

Absent from the NOPR is a candid assessment of some real impediments to new transmission upgrades, including state-mandated retail rate freezes and the unwillingness of many utilities to expose the allowed return on their rate bases to renewed scrutiny as a condition to recovering new investments. These are the problems that need to be addressed and any discussion of “participant funding” or “incentives” may, in many cases, be a diversion.

However, Industrial Consumers also believe that some transmission owners may under-build their transmission systems in order to preserve the market power of their generation and retail marketing affiliates. This problem cannot be solved by changing the pricing policy. In fact, some forms of participant funding are a manifestation of this exercise of market power. Industrial Consumers believe that pursuant to FERC’s mandate under § 205 of the Federal Power Act (FPA) to assure just and reasonable rates and FERC’s mandate under § 206 to redress undue discrimination, the Commission should require transmission owners to show due diligence/reasonable efforts to ensure transmission adequacy as a condition of market-based rate authorization and as another market power mitigation measure in the SMD rule.

Paragraph 219. The Commission agrees that the operational limits of both the resources and the transmission systems need to be fully considered in the design of the specific market rules. For example, there is likely a need to calculate opportunity costs for hydroelectric resources differently from thermal plants. These differences can affect market mitigation measures. However, the Commission is concerned about whether different market designs can be in place in the Northwest and the rest of the West, and ask for comment on whether the entire West must have a common set of market rules to eliminate seams and prevent manipulation.

Response of Industrial Consumers:

There should be a common market design throughout the West that internalizes the unique features of the Northwest hydro resource base with the rest of the Interconnection's thermal resource base. We also believe that transmission products and services in the West should have the same "look and feel" as comparable products and services in the East. Independent Market Monitors in the West will likely face challenges that are different from their Eastern peers but that only indicates a need to retain the appropriate expertise.

Ultimately, there should be a single RTO or ITP for the entire Western Interconnection. Industrial Consumers believe that allowing the proposed three western RTOs to run their course for some period of time will make the case for eventual consolidation.

Congestion Revenue Rights

General Features

Paragraph 238. The Independent Transmission Provider would be required to offer CRRs for all of the transmission transfer capability on the grid, but it would not be allowed to sell more rights than can be accommodated. CRRs would be available over a variety of terms, such as weekly, monthly, yearly and perhaps for longer terms. If an entity pays to construct new generation or transmission facilities that add transfer capability, and the costs of the upgrade are not rolled in, the entity would receive the CRRs associated with the new transfer capability. In the past the Commission has allowed credits for upgrades; is there still a role for credits under Standard Market Design?

Response of Industrial Consumers:

CRRs should not be offered as incentives or "credits" to induce new transmission upgrades. CRRs exist for the limited purpose of providing loads insurance against congestion costs and

must always “follow the loads.” By limiting the ability to own and use CRRs to LSEs and MPLs, the potential for gaming is greatly reduced.

Notwithstanding, it would not be unreasonable for merchant developers of new High Voltage Direct Current (HVDC) transmission facilities to be permitted to offer CRRs to LSEs and MPLs through those developers that own open season auction for new HVDC transmission capacity. However, these developers should be limited to entities that do not possess exclusive eminent domain privileges for new transmission facilities in the geographical area where the new HVDC transmission facilities would be constructed. Such CRRs would be defined on a point-to-point basis between the injection point of power from the Alternating Current (AC) transmission system into the HVDC transmission facilities and the extraction point from the HVDC facilities back into the AC transmission system at a different location. Moreover, the merchant developer would be responsible for paying any congestion rents associated with those CRRs to holders of the CRRs awarded by that developer. In exchange, the ITP would pay the merchant transmission developers a special congestion rent based on the real-time locational price difference across the HVDC facility times the actual amount of transmission capacity made available across that HVDC facility to the ITP in real-time operations. This would hold the ITP harmless from the merchant transmission developer’s performance while properly matching the risks and rewards associated with merchant transmission with the merchant transmission developer.

Industrial Customers do not believe merchant AC transmission facility development is feasible at this time because flow across individual AC transmission facilities is not generally controllable with present technology. For practical purposes, a HVDC transmission facility appears to the AC transmission system as a load on one end and a generator on the other end. Thus, HVDC transmission facilities readily lend themselves to competitive merchant

development except where such developers might have market power over such development through exclusive eminent domain privileges for transmission facilities in the geographic area where the transmission facilities would be constructed.

Requirement for Offering Rights

Paragraph 249. Congestion Revenue Rights could be offered for various terms, *e.g.*, one month or five years. Some customers may desire CRRs with multi-year terms to correspond to the terms of long-term power contracts, including contracts used to satisfy the resource adequacy requirement. At the same time, it may be difficult for the market to value long-term CRRs until a region has actual operating experience under an LMP congestion management system. This could create problems in an area that auctions all CRRs and allocates the auction revenue rights to load. The NOPR seeks comment on whether the Commission should require the Independent Transmission Provider to offer multi-year CRRs when Standard Market Design is first implemented. Additionally, the NOPR seeks comment on whether the ITP should be required to offer CRRs with terms tied to the planning horizon used in the region to satisfy the resource adequacy requirement.

Response of Industrial Consumers:

Industrial Consumers believe that CRRs or the value of those CRRs as determined by an auction by the ITP should be directly allocated to LSEs and Market-Participating Loads. Allocation of CRRs (or alternatively of the value of those CRRs as determined from an auction of those CRRs) ensures that end-use customers truly receive the value of the transmission system that have earned by paying for the embedded cost for the transmission system via access charges. Auctions of CRRs should be available for terms out to the length of any planning horizon that is established in the region to satisfy any resource adequacy requirements that may be in the final

rule. Auctions should be limited to LSE and Market-Participating Loads, or non-LSEs acting as agents for LSEs, to prevent the gaming of the dispatch process by the ownership of CRRs.

Funding for the Congestion Revenue Rights

Paragraph 251. The Commission proposes that any revenue surpluses be paid to transmission owners, but seeks comment on the potential of this policy to discourage transmission expansions and if alternative mechanisms should be used to distribute the revenue surpluses.

Response of Industrial Consumers:

Industrial Consumers are concerned that if revenue surpluses from the collection of LMP charges less payments to generators and CRR holders are paid to transmission owners, those owners will be motivated to understate transmission capacity available for CRRs during the simultaneous feasibility evaluation. An ITP that owned transmission facilities or in any way received a portion of these excess LMP revenues would be motivated to understate the amount of CRRs available to transmission customers. Even if the ITP did not own transmission facilities or did not benefit in any way from surplus LMP revenues, the ITP would have to be especially vigilant to make sure that any contribution by transmission owners to the simultaneous feasibility testing process for CRRs was not overly conservative. In general, surplus LMP revenues should be used to make up for future LMP revenue shortfalls. However, surplus LMP revenue balance at year-end should be returned to LSEs and MPLs. This approach will ensure transmission owners and ITPs are properly motivated to maximize the commercial availability of CRRs.

Allocation of Congestion Revenue Rights

Paragraph 376. The Commission seeks comment as to whether and under what circumstances load growth should be accommodated in the direct allocation of Congestion Revenue Rights.

Response of Industrial Consumers:

Each ITP should be required to establish guidelines for certifying forecasted load growth that qualify for CRR allocation (or an allocation of the value associated with CRRs that would have been allocated). The ITP's Market Monitor should oversee this process and monitor the accuracy of past forecasts, and, on its own initiative, recommend changes to the process to minimize over- or under-allocation of CRRs on the basis of such forecasts. In the case of loads in retail open-access states, a similar process should be established to accommodate any expected increase in demand at a commercial or industrial facility.

Paragraph 378.

Either of two methods could ensure that current customers receive the value of their current contracts (actual or implicit) – direct assignment and an auction with a revenue assignment. For network contracts and implicit contract, it is likely that customers would continue service for the foreseeable future (without a contract termination date). The NOPR seeks comment on what type of term should be used for purposes of the Congestion Revenue Rights allocation for these contracts.

Response of Industrial Consumers:

A short transition period should be allowed given the uncertainties associated with market operation and CRR allocation. One source of uncertainty is the introduction and efficacy of option and flowgate rights. Regional deference on this issue should not be allowed if the LSEs

and MPLs in any region oppose such action. However, in regions where a substantial portion of the total CRRs were allocated, a shorter transition period to auctions may be needed to ensure liquid trading of CRRs and that LSEs and MPLs can adequately hedge their transactions against congestion.

For reasons stated elsewhere in Industrial Consumers' comments, we believe that, initially, CRRs should be allocated directly to LSEs or Market-Participating Loads. If auctions are used, only LSEs, Market-Participating Loads, or non-LSEs acting as agents for LSEs or Market-Participating Loads should be allowed to participate in such auctions. When an MPL in a retail open-access state switches supplier(s), the appropriate CRRs "follow the load." The LSE that formerly served the load must not be allocated those CRRs (or the value of the CRRs as determined by auction) on a going-forward basis and any CRRs the LSE retains after the customer switches supplier(s) must be surrendered to the ITP for reallocation to the MPLs or reconfiguration, as necessary. Speculative ownership of CRRs should be prohibited until such time as an ITP's Market Monitor certifies that generator market power has been eliminated. CRRs should never be allocated to transmission owners such as ITCs, or marketers or brokers that are not acting as agents for LSEs or MPLs.

Paragraph 380. Customers may desire long-term Congestion Revenue Rights to correspond to the term of the long-term contracts used to satisfy the long-term resource adequacy requirement. The NOPR seeks comment on whether the SMD should require long-term Congestion Revenue Rights in such cases.

Response of Industrial Consumers:

The Commission should require that ITPs offer CRRs by auction for a term long enough to meet any planning horizon established as part of any resource adequacy requirement included in the

final rule. Moreover, to the extent the Commission initially requires allocation of CRRs they should be available in allocations of a long enough term to meet any planning horizon established as part of any resource adequacy requirement included in the final rule. Such allocated CRRs will need to be reallocated from LSEs to MPLs, or other LSEs acting as agents for MPLs, when, and if, such load chooses a different supplier under retail access.

Load bids for long-term CRRs will not go to infinity because if the ITP is required to build sufficient transmission capacity such that all firm loads can be served reliably (this is likely), there will be sufficient CRRs for all loads, but not necessarily the specific CRRs certain loads desire. However, the desirable CRRs may be expensive in some cases due to insufficient transmission capacity in the form of CRRs available to reach economic sources of capacity. This possibility reflects the scarcity of economic capacity on a locational basis in the long-term forward market the FERC is trying to force into existence with their resource adequacy requirement. The ability to meet the requirement with newly constructed generation or demand response should limit this market power in the forward generation capacity market. However, there may still be some siting barriers for new generation in certain geographical areas that will reduce the effectiveness of this theoretical market discipline. This issue also relates to the participant funding versus rolled-in transmission upgrades issue because the local scarcity of economic capacity in the forward market signals a need for additional transmission capacity. If siting barriers for transmission (or FERC's regulatory policies economically) prevent the construction of additional transmission capacity and siting barriers are in the way of new local generation capacity, the existing generation in the local area will have market power that can only be mitigated by restricting that generation capacity to cost-based rates in the long-term forward generation capacity market.

Paragraph 382. The SMD NOPR establishes a preference for the auction of Congestion Revenue Rights. However, for an initial transition period of four years, this rulemaking proposes to allow regional flexibility on this issue. The NOPR seeks comment on whether to allow a transition period before the start of Congestion Revenue Rights auction allocations and, if so, what the length of such a transition should be.

Response of Industrial Consumers:

A transition period of at least four years should be allowed given the uncertainties associated with market operation and CRR allocation. One source of uncertainty is the introduction and efficacy of option and flowgate rights. However, the proposed four-year transition period may need to be shortened significantly if a substantial portion of the total CRRs have been allocated in order to provide liquid trading of CRRs and ensure that LSEs and MPLs can hedge their transactions against congestion. Regional deference on this issue should not be allowed if the LSEs and MPLs in any region oppose such action.

For reasons stated above in these comments, Industrial Consumers believe that, initially, CRRs should be allocated directly to LSEs and Market-Participating Loads (MPLs). If auctions are used, only LSEs, MPLs, or non-LSEs acting as agents for LSEs or MPLs should be allowed to participate in such auctions. When a Market-Participating Load switches supplier(s), the appropriate CRRs “follow the load.” The LSE that formerly served the load must not be allocated those CRRs on a going-forward basis and any CRRs the LSE retains after the customer switches supplier(s) must be surrendered to the ITP for reallocation to the MPL or reconfiguration, as necessary. Speculative ownership of CRRs should be prohibited until such time as an ITP’s Market Monitor certifies that generator market power has been eliminated.

CRRs should never be allocated to transmission owners such as ITCs, or marketers or brokers that are not acting as agents for LSEs or loads.

Long-Term Resource Adequacy

Level of Resource Adequacy

Paragraph 489. An ITP would be required to do an annual demand forecast for its area. After the area's demand is forecast, the ITP must assess whether the collective resource plans of load-serving entities in this area are adequate to meet the projected future peak need with allowance for adequate reserves. This requires a regional determination of the appropriate level of resource reserves, for example, whether the reserve margin (if reserve margin is the region's measure of resource adequacy) should be 12, 15, 18 percent, or another level. The Commission seeks comment on and encourages regional discussion of appropriate planning targets in energy-limited areas, specifically on how to incorporate volatility of annual hydropower supply.

Industrial Consumers:

The proposed reserve margin floor of 12% is adequate absent some extenuating circumstance such as a drought in regions dependent on hydropower. The decision to temporarily increase the regional reserve margin should be determined in a RTO's or ITP's stakeholder process and subject to FERC approval.

Paragraph 492. The Commission proposes that the level of reserves should be set by a Regional State Advisory Committee. States in the region should have this strong role in determining the level of resource adequacy because a higher level provides greater reliability and also incurs higher costs that affect most retail customers. However, the NOPR asks for comment on what fallback provision should be employed if the Regional State Advisory Committee does not reach agreement on the appropriate level of resource adequacy.

Response of Industrial Consumers:

Industrial Consumers believe that a 12% default level for a regional reserve margin is adequate absent some extenuating circumstance such as drought, coal strike (in any region dependent on coal-fired generation), and similar contingencies. We oppose giving the RSAC unilateral control for setting the regional reserve margin. The level should be set in the stakeholder process with state participation.

Load-Serving Entities Share of the Regional Resource Requirement

Paragraph 498. The NOPR requests comment on two methods for determining each load-serving entity's share of the regional requirement.

One method is to allocate the future resource adequacy needs to loads based on each load's forecasted future demand. For example, if the load forecast is for three years ahead and a particular load is growing faster than the regional average, its share of the adequacy requirement could be based on its forecast load ratio share for three years ahead, not on the present load ratio share. This method assigns more adequacy responsibility – and cost – to faster growing loads. However, if the Independent Transmission Provider's forecast is made through a "bottom up" method that adds up individual load forecasts, it must rely on each load to report its growth rate accurately. This approach creates an incentive for loads to understate their growth to lower their resource costs.

The second method is to allocate the future adequacy requirement to loads based on each load's most recently documented load ratio share. This method is less subject to manipulation. However, an area with a slow load growth located within a region of generally high load growth may subsidize the high reserve needs of its neighbors.

The NOPR asks for comment on which of these two methods the Commission should choose in the Final Rule. Alternatively, the NOPR seeks comments on whether this issue should be left to regional determination.

Response of Industrial Consumers:

The method should not be left to regional determination because this would be inconsistent with the fundamental objective of a standard market design. Industrial Consumers support the second method posed in the NOPR but subject to an adjustment. This adjustment would reflect the LSE or MPL's need for additional CRRs during the planning horizon. Industrial Consumers are concerned that neither method may adequately capture resource diversity and that a substantially additive approach will over-estimate total resource needs and result in too much generation at great cost to consumers.

Paragraph 502. Once each load-serving entity's share of the regional adequacy requirement is determined, the Independent Transmission Provider must inform each load-serving entity of its share. It must require each load-serving entity to report and document how it plans to meet its adequacy requirement. The time available to the load-serving entity from being informed of its resource share to having to report to the Independent Transmission Provider must be adequate to allow it to develop arrangements for meeting future resource needs. The NOPR asks for comment on how much time is needed for these purposes.

Response of Industrial Consumers:

Industrial Consumers have no comment on this issue at this time.

Resources That Can Satisfy the Resource Needs

Resource Standards

Paragraph 510. The Independent Transmission Provider must determine if each load-serving entity's planned resources meet certain standards. The resources must meet the standards to count toward satisfying the entity's share of the regional resource requirement. Both generation and interruptible or biddable load must meet standards to satisfy the requirement. The NOPR proposes here certain minimum standards for comment. The Commission also is considering in the Final Rule to ask the North American Energy Standards Board (NAESB) to develop more detailed standards for determining whether resources satisfy the resource adequacy requirement, and seeks comments on this approach.

Response of Industrial Consumers:

Industrial Consumers believe that the minimum standards, and any standards developed by NAESB, should address the minimum necessary resource requirements necessary to fulfill the ITP's responsibility to maintain short-term reliability. The standards must not attempt to judge or prescribe the resource technology or fuel mix adopted by an LSE or Market-Participating Load to meet its requirements, except to the extent the resource mix may adversely impact short-term reliability.

Generation Standards

Paragraph 512. Generation must be owned by or under contract to the load-serving entity and committed to meet the resource needs of the load-serving entity at least during certain conditions such as an operating reserve shortage. The Independent Transmission Provider must be satisfied that the generation is physically feasible; that is, the generating units are capable of generating the power planned, and enough transmission is available to deliver the power from

the generating station to the particular load. The generating units under contract must be real and specific generators. Because the purpose of this requirement is to encourage the development of new resources including new generation, generation under contract for development within the planning horizon should satisfy the requirement. Should the Commission specify the contract content needed to rely on generation under development? If so, should the Final Rule refer this matter to NAESB to determine the content?

Response of Industrial Consumers:

LSEs or loads should only be required to summarize their respective resources and perhaps notarize the accuracy of the information. The ITP could then determine whether the generation and transmission enabled physical delivery to the load.

Paragraph 513. For these reasons also, a contract with a marketer to deliver power at a future time from unspecified sources cannot satisfy the requirement. The purpose here is not to transfer financial risk for nonperformance to a marketer but to ensure performance, that is, to ensure that enough actual, deliverable generating capacity is available or developed at satisfactory locations to avert a future shortage. However, a forward contract with a marketer that is linked to specific generation and demonstrates transmission adequacy would satisfy the requirement. The NOPR asks for comment on whether the Commission should allow a liquidated damages contract for power from unspecified sources to be included in the resource adequacy plan, and also on whether it should allow a load-serving entity that initially fails to satisfy the resource adequacy contract, but later brings in new resources under a liquidated damages contract for the amount of its resource deficiency, to avoid the penalty price and first curtailment in the spot market during a shortage.

Response of Industrial Consumers:

Industrial Consumers have no comment on this issue at this time.

Transmission Standards

Paragraph 514. Generation must be deliverable to satisfy the requirement. A Congestion Revenue Right for the appropriate year is one way to satisfy this requirement. The NOPR proposes to adopt a practice (used in PJM) that allows a resource owner to pay for the development of adequate transmission to deliver its energy to a load and then to sell its Congestion Revenue Rights while still satisfying the requirement that its generation be deliverable. Should a commitment by any load-serving entity to pay congestion costs no matter how high also satisfy the requirement? If so, how should the Independent Transmission Provider respond if the sum total of all such commitments exceeds the available capacity of a bottleneck interface?

Response of Industrial Consumers:

Industrial Consumers have no comment on this issue at this time.

Planning Horizon

Paragraph 524. The purpose of a forward-looking resource adequacy requirement is to create a demand for new resource entry in advance of a shortage so that enough supply construction and demand response infrastructure installation are begun in time to avert the shortage. The planning horizon for each region is the number of years ahead for which the Independent Transmission Provider must forecast annually its area's load, as well as the number of years ahead for which load-serving entities must show that they have adequate resources. The Commission proposes to have the Regional State Advisory Committee determine the planning horizon for the region. The Independent Transmission Provider (including each Independent

Transmission Provider in a region with more than one Independent Transmission Provider) must provide information and support to the Committee, as requested, to help it to determine the region's planning horizon. The NOPR requests comment on how to resolve any lack of consensus within the Committee regarding the appropriate planning horizon. The NOPR also asks for comment on whether the Commission should establish limits on the region's choice of planning horizon, such as at least three years and no more than five years.

Response of Industrial Consumers:

The planning horizon should be reasonably standardized across all regions, recognizing that the planning horizon for transmission expansion and generation differ. To the extent the objective of the resource adequacy requirement is to satisfy the ITP's responsibility to maintain short-term reliability on a going-forward basis (Industrial Consumers' recommendation), a standard three-year planning horizon seems more than adequate. Three years should be plenty of time to get new peaking units sited and constructed. The exception, of course, would be in those regions that historically have had a long lead-time for generation permitting and additions.

Paragraph 525. The NOPR also asks for comment on whether to have a resource adequacy requirement before the end of the first planning horizon period. For example, if the horizon is three years, should there be a requirement for resource adequacy in the first two years?

Response of Industrial Consumers:

Yes, if the purpose of the resource adequacy requirement is to maintain short-term reliability.

Enforcement

Paragraph 526. The Commission proposes a procedure to enforce the resource adequacy requirement, along with some alternative enforcement procedures, and asks for comment on the most effective enforcement method. Unlike some ICAP requirements, the approach adopted in

the NOPR does not require a load-serving entity to pay a penalty in the near term for failure to have adequate future resources. The Commission's proposed approach relies primarily on two enforcement mechanisms: (1) a Commission-set tariff penalty imposed on a load-serving entity that threatens reliable transmission operation by taking energy from the spot market during a shortage in a year for which it fails to meet its resource adequacy requirement, and (2) a Commission requirement that the spot market electric service of such a load-serving entity must be curtailed first when the shortage that is severe enough to require that some customers be curtailed. Each of these mechanisms, the penalty rate and the load curtailment, would occur at the end of the planning horizon, not the beginning. The penalty price would increase in stages as the shortage becomes more severe. For example, the penalty price could be \$500 (in addition to the spot market energy price) when operating reserves are just below the minimum level, \$600 when operating reserves are more than below 1 percent below the minimum level, \$700 when operating reserves are more than 2 percent below the minimum level, and so on. The Commission asks for comment on having such a graduated penalty and the appropriate penalty rates.

Response of Industrial Consumers:

The modification to the resource adequacy requirement proposed by Industrial Consumers would eliminate the need for such penalties. Industrial Consumers also believe that exposure to spot market risk should be ample incentive to plan on a forward a basis.

Paragraph 534. If the Independent Transmission Provider does not have direct control of the circuit equipment needed to implement a curtailment and relies on the load-serving entity to follow its instructions to implement a curtailment, the load-serving entity would be subject to a severe penalty for the unauthorized taking of power from the spot energy market because this

jeopardizes grid reliability. The NOPR proposes to charge the applicable Locational Marginal Price plus \$1000/MWh for all unauthorized energy taken following an instruction to implement curtailment. The NOPR also seeks comment on whether the \$1000/MWh penalty would be sufficient to deter unauthorized taking of energy and, if these penalties are paid, who should receive these revenues.

Response of Industrial Consumers:

Industrial Consumers support the need for an effective deterrent against unauthorized energy taken after the ITP has instructed the execution of a curtailment. Exposure to the spot market risk should be adequate deterrent.

Paragraph 536. Having presented the Commission's enforcement proposal, the NOPR suggests variations of this proposal and asks for comments on these alternatives. As mentioned, under the proposal the penalty rate or load curtailment would occur at the end of the planning horizon, not the beginning. However, the NOPR asks for comment on this approach compared to an alternative approach that may provide a more immediate and effective incentive to a load-serving entity to take action to provide for future resources well in advance of facing a penalty or first curtailment. This is to impose a penalty on the load-serving entity immediately (that is, in year 2004 to continue the example used above) if it fails to submit a satisfactory plan to meet its 2007 resource adequacy requirement. The Commission did not propose this option as its first choice because it has some of the unfavorable features of some ICAP programs that focus more on avoiding immediate penalties than on motivating long-term resource development. However, the NOPR asks for comments on the merits of this alternative approach.

Response of Industrial Consumers:

Industrial Consumers have no comment on this issue at this time.

Paragraph 537. As presented, the Independent Transmission Provider audits the plan of each load-serving entity only at the beginning of the planning period (in 2004 in the example above). The Commission is concerned that a load-serving entity may submit a satisfactory plan but fail to fully implement the plan. The proposal permits but does not require the Independent Transmission Provider to audit each year the progress of the load-serving entity in implementing its plan, and the NOPR asks whether the Final Rule should explicitly require this. If the load-serving entity's progress is unsatisfactory, should the Independent Transmission Provider find that it fails to satisfy its resource adequacy requirement? If the load-serving entity implements its plan but some of its resources fail to perform when needed during a shortage, should that load-serving entity, in addition to having a greater need for spot market energy at a presumably higher spot market price, also be subject to either of the enforcement mechanisms set out above?

Response of Industrial Consumers:

Industrial Consumers believe that exposure to spot market risk is adequate incentive to plan for resource adequacy on a forward basis.

Paragraph 538. Another feature of the Commission's proposal is that it would not affect electric service from the self-generation and bilateral contracts of a load-serving entity that fails to meet its resource adequacy requirement (except that it would be subject to a penalty price during a shortage for balancing energy in the spot energy market). The Commission asks for comment on whether this proposal unduly weakens the incentive to develop regional resources and whether, in the alternative, the Independent Transmission Provider should first curtail service to the load serving entities that failed to meet their share of the resource adequacy requirement, including transmission service from resources acquired outside the spot market, freeing up those resources for the use of those that planned adequately.

Response of Industrial Consumers:

Industrial Consumers have no comment on this issue at this time.

Paragraph 541. Finally, the Commission’s proposed enforcement mechanisms are designed to create an incentive to avoid a future penalty or first curtailment. During the public outreach process for developing this proposed rule, some commenters recommended a stronger ITP role in compliance with a mandatory resource adequacy requirement. One proposal is for the Commission to require the ITP to procure resources on behalf of load-serving entities that fail to meet fully their requirement and charge them for the cost of the resources. Another is for the Final Rule to require the ITP to either (1) calculate an expected capacity deficiency and purchase the call options necessary to meet the adequacy requirement on behalf of the load-serving entities, allocating costs pro rata, or (2) require load-serving entities to purchase reserves at the price produced by an ITP-run auction. These approaches have advantages as well as disadvantages. Among the advantages are that they provide a greater assurance of achieving adequate resources and avoid the possible pitfalls of applying penalty rates or first curtailment. Among the disadvantages are that they take away one demand response option, namely curtailment, from the range of policy choices. Also, the latter approaches appear to require the ITP to take a position in the capacity market, which places the ITP in a role that may be incompatible with its independence. What is the effect of these alternate enforcement mechanisms on the incentives and business risks of the load serving entities in the region? Is there another enforcement mechanism that is both appropriate and effective?

Response of Industrial Consumers:

Industrial Consumers have no comment on this issue at this time.

Regional Flexibility

Paragraph 549. The Commission proposes to apply the requirement set out above to all regions, including regions that already have an ICAP requirement that has been previously approved by the Commission. This requirement would replace the current ICAP program. Nevertheless, the NOPR asks for comment on whether, under the approach to resource adequacy proposed here, the Final Rule should require an ITP to create a market to facilitate load-serving entities meeting their resource adequacy requirement efficiently.

Response of Industrial Consumers:

Industrial Consumers recommend that the resource adequacy proposal be modified (and greatly simplified) as discussed above in section I.D.

Paragraph 550. Despite the claimed flexibility of the Commission's proposed approach, regions with a historical reliance on a tight pool for sharing reserve may argue for a continuation of some form of ICAP program. The NOPR asks for comment on how existing Commission-approved ICAP mechanisms can be transitioned and modified so as to be made consistent with our resource adequacy proposal here without disrupting financial commitments made under existing rules. What are the disadvantages of particular elements of the ICAP approach that should be avoided in the approach proposed here? Do any of the enforcement proposals or alternatives discussed above re-introduce any such disadvantageous elements?

Response of Industrial Consumers:

Industrial Consumers believe that the ICAP programs of existing ISOs should be abandoned as soon as possible and replaced with the modified resource adequacy requirement proposed in these comments.

State Participation in RTO Operations

Paragraph 553. The NOPR seeks comment on whether there should be a single Regional State Advisory Committee, or separate committees for siting and other issues. The NOPR also seeks comment on how the state representatives should be selected (*e.g.*, whether the governor should select them or some other process should be used).

Response of Industrial Consumers:

Industrial Consumers do not support the need for Regional State Advisory Committees. State regulators should be encouraged to participate in each RTO's or ITP's stakeholder process.

There is no need for a formal selection process. Any state regulatory commissioner or member of a commission's staff should be able to participate. In existing ISO/RTO stakeholder processes, state regulators typically participate as non-voting member of the stakeholder process and therefore no limit is necessary on their participation.

Respectfully submitted,

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