transmission is sold at retail as part and parcel of the delivered product called electric energy, the transaction is a sale of electric energy at retail. Under the FPA, the Commission's jurisdiction over sales of electric energy extends only to wholesale sales. However, when a retail transaction is broken into two products that are sold separately (perhaps by two different suppliers: an electric energy supplier and a transmission supplier), we believe the jurisdictional lines change. In this situation, the state clearly retains jurisdiction over the sale of the power. However, the unbundled transmission service involves only the provision of "transmission in interstate commerce" which, under the FPA, is exclusively within the jurisdiction of the Commission. Therefore, when a bundled retail sale is unbundled and becomes separate transmission and power sales transactions, the resulting transmission transaction falls within the Federal sphere of regulation.

In asserting jurisdiction over unbundled retail transmission in interstate commerce by public utilities, the Commission in no way is asserting jurisdiction to order retail transmission directly to an ultimate consumer. Section 212(h) of the FPA clearly prohibits us from doing so. In addition, as stated in both the initial Stranded Cost NOPR and the Open Access NOPR, we do not address whether states have authority to order retail wheeling in interstate commerce. The Commission's assertion of jurisdiction is that if retail transmission in interstate commerce by a public utility occurs voluntarily or as a result of a state retail wheeling program, the Commission has exclusive jurisdiction over the rates, terms, and conditions of such transmission and public utilities offering such transmission must comply with the FPA by filing proposed rate schedules under section 205.

The Commission clarifies that nothing in this jurisdictional determination changes historical state franchise areas or interferes with state laws governing retail marketing areas of electric utilities. Section 212(g) of the FPA prohibits Commission orders that would be inconsistent with such laws. However, we reject arguments made by some of the commenters that section 212(g) could somehow be construed to give states authority over the rates, terms, and conditions of unbundled interstate transmission within retail marketing areas.[FN542] While our ***21626** jurisdiction cannot affect whether and to whom a retail electric service territory (marketing area) is to be granted by the state, and whether such grant is exclusive or non-exclusive, neither can state jurisdiction affect this Commission's exclusivejurisdiction over transmission in interstate commerce by public utilities.

In response to several of the commenters, we further clarify that the Commission's jurisdiction over the rates, terms, and conditions of unbundled retail transmission is no broader than our authority over transmission used for wholesale transactions, and will not affect matters otherwise left to the states by Congress.[FN543] The Federal Power Act recognizes that retail marketing areas are governed by state law. Moreover, we believe that states have authority over the service of delivering electric energy to end users. In exercising this authority, state regulatory commissions and state legislatures have traditionally developed social and environmental programs suited to the circumstances of their states. State regulation of most power production and virtually all distribution and consumption of electric energy is clearly distinguishable from this Commission's responsibility to ensure open and non-discriminatory interstate transmission service. Nothing adopted by the Commission today, including its interpretation of its authority over retail transmission or how the separate distribution and transmission functions and assets are discerned when retail service is unbundled, is inconsistent with traditional state regulatory authority in this area.

The Commission reiterates its strong interest in preventing any balkanization of the interstate power market. Although the Commission believes its Final Rule will accommodate retail competition, if it is offered voluntarily by a utility or ordered by a state, our policies relate only to the bulk power market and not traditional state regulation of the retail market.[FN544]

NARUC has requested that the Commission specifically clarify in §35.27 of its proposed rules[FN545] that nothing in our final rule limits the authority of a state commission "to allow or disallow the inclusion of the costs of electric energy purchased at wholesale in retail rates subject to such State commission jurisdiction." We will adopt NARUC's proposal with modification, but add it as a separate subsection. The Final Rule adopts a new §35.27(b) as follows:

Nothing in this part (i) shall be construed as preempting or affecting any jurisdiction a state commission or other state authority may have under applicable state and federal law, or (ii) limits the authority of a state commission in accordance with state and federal law to establish (a) competitive procedures for the acquisition of electric energy, including demand-side management, purchased at wholesale, or (b) non-discriminatory fees for the distribution of such electric energy to retail consumers for purposes established in accordance with state law.

With respect to the Commission's adoption of the Open Access NOPR's functional/technical tests for determining what facilities are Commission-jurisdictional facilities used for transmission in interstate commerce and what facilities are state-jurisdictional local distribution facilities, the case law supports a bright line for unbundled wholesale transmission, i.e., transmission of electric energy that is being sold for resale. This is consistent with the bright line drawn by Congress to fill the Attleboro gap for regulating wholesale sales of electric energy. The case law also supports a bright line with respect to retail transmission by intervening utilities, i.e., transmission by those utilities between the new retail generation supplier and the public utility that previously provided bundled retail service to the end user. However, despite many commenters' arguments to the contrary, we cannot divine such a bright line for unbundled retail transmission by the public utility that previously provided bundled retail service to the end user. In fact, the limited case law, including CL&P and Colton, supports a case-by-case determination. [FN546] Accordingly, we believe our technical test, with its seven indicators, will permit reasoned factual determinations in individual cases.

Although we are unable to draw the bright line for local distribution facilities that many commenters would like, we believe it is important to make two clarifications regarding local distribution in the context of retail wheeling. First, even when our technical test for local distribution facilities identifies no local distribution facilities for a specific transaction, we believe that states have authority over the service of delivering electric energy to end users. Second, through their jurisdiction over retail delivery services, states have authority not only to assess stranded costs but also to assess charges for stranded benefits, such as low-income assistance and demand-side management. Because their authority is over services, not just the facilities, states can assign stranded costs and benefits based on usage (kWh), demand (kW), or any combination or method they find appropriate. They do not have to assign them to specific facilities.[FN547]

Thus, while we believe in most cases there will be identifiable local distribution facilities subject to state jurisdiction, we also believe that even where there are no identifiable local distribution facilities, states nevertheless have jurisdiction in all circumstances over the service of delivering energy to end users. Under this interpretation of state/federal jurisdiction, customers have no incentive to structure a purchase so as to avoid using identifiable local distribution facilities in order to bypass state jurisdiction and thus avoid being assessed charges for stranded costs and benefits.

Based on concerns raised by state commissions as well as some utilities, we have further determined that it is appropriate to provide deference to state commission recommendations regarding certain transmission/local distribution matters that arise when retail wheeling occurs. We also believe it is important to develop mechanisms to avoid regulatory conflict and to help provide certainty to utilities as to which regulator has jurisdiction over which facilities. These are discussed below.

***21627** Determining where to draw the jurisdictional line for facilities used in unbundled retail wheeling transactions will involve case-specific determinations that evaluate the seven local distribution indicators that we are adopting. We believe that the Commission should take advantage of state regulatory authorities' knowledge and expertise concerning the facilities of the utilities that they regulate. Therefore, in instances of unbundled retail wheeling that occurs as a result of a state retail access program, we will defer to recommendations by state regulatory authorities concerning where to draw the jurisdictional line under the Commission's technical test for local distribution facilities, and how to allocate costs for such facilities to be included in rates, provided that such recommendations are consistent with the essential elements of the Final Rule.[FN548] Moreover, we recognize that in some cases the Commission's seven technical factors may not be fully dispositive and that states may find other technical factors that may be relevant. We will consider jurisdictional recommendations by states that take into account other technical factors that the state believes are appropriate in light of historical uses of particular facilities.

Some commenters have asked the Commission to provide a forum to prevent or resolve disputes over the correct classification of facilities as transmission or local distribution. As a means of facilitating jurisdictional line-drawing, we will entertain proposals by public utilities, filed under section 205 of the FPA, containing classifications and/or cost allocations for transmission and local distribution facilities. However, as a prerequisite to filing transmission/local distribution facility classifications and/or cost allocations with the Commission, utilities must consult with their state regulatory authorities. If the utility's classifications and/or cost allocations are supported by the state regulatory authorities and are consistent with the principles established in the Final Rule, the Commission will defer to such classifications and/or cost allocations.[FN549] We encourage public utilities and their state regulatory authorities to attempt to agree to utility-specific classifications and allocations that the utility may file at the Commission.

A number of commenters have asked the Commission to defer to state commission recommendations or decisions regarding rates, terms and conditions of unbundled retail transmission in interstate commerce by public utilities. Some have suggested that we set broad guidelines for such rates, terms, and conditions, and then allow states to actually implement the guidelines. While the Commission cannot simply turn over its jurisdiction for the states to implement, we understand the concerns raised by many state regulators and believe that deference to state commissions with regard to rates, terms, and conditions may be appropriate in some circumstances, as discussed below.

As we determined in the NOPR, when unbundled retail wheeling in interstate commerce occurs, the transaction has two components for jurisdictional purposes—a transmission component and a local distribution component. The Commission has jurisdiction over facilities used for the transmission component of the transaction, and the state has jurisdiction over facilities used for the local distribution component.[FN550] Thus, the rates, terms and conditions of unbundled retail transmission by a public utility must be filed at the Commission. When this occurs, we will generally expect unbundled retail wheeling customers to take service under the same FERC tariff that applies to wholesale customers. However, if the unbundled retail wheeling occurs as part of a state retail access program, it may be appropriate to have a separate retail transmission tariff[FN551] to accommodate the design and special needs of such programs. In such situations, the Commission will defer to state requests for variations from the FERC wholesale tariff to meet these local concerns, so long as the separate retail tariff is consistent with the Commission's open access policies and comparability principles reflected in the tariff prescribed by this Final Rule. In addition, rates must be consistent with our Transmission Pricing Policy Statement, and the guidance herein concerning ancillary services.[FN552]

A final jurisdictional issue raised in the Open Access NOPR concerns buy-sell transactions. We remain concerned, just as we were with buy-sell arrangements in the gas industry, that buy-sell arrangements can be used by parties to obfuscate the true transactions taking place and thereby allow parties to circumvent Commission regulation of transmission in interstate commerce. Thus, we reaffirm our conclusion that we have jurisdiction over the interstate transmission component of transactions in which an end user arranges for the purchase of generation from a third-party. However, we recognize that there is a wide range of programs and transactions that might or might not fall within this category. We will address these on a case-by-case basis.

In summary, the Commission reaffirms and clarifies its prior jurisdictional conclusions and tests for determining the demarcation between federal and state jurisdiction over transmission in interstate commerce and local distribution. We have attempted to address these issues in a way that provides for flexibility and recognition of legitimate state concerns. With regard to retail services, we recognize the states' concerns that the unbundling of retail transactions would result in changes from what historically has been regulated by the states (principally, the rates of transmission assets previously included in retail rate base). However, the decision to provide unbundled retail wheeling is not the Commission's to make because we have no authority to order transmission directly to an ultimate consumer. In addition, even if a retail access program occurs, we do not believe the unbundling of retail transactions will radically change fundamental state authorities, including authority to regulate the vast majority of generation asset costs, the siting and maintenance of generation facilities and transmission lines, and decisions regarding retail service territories. Further, the Commission intends to be respectful of state objectives so long as they do not balkanize interstate transmission of power or conflict with our interstate open access policies. As the electric industry and state regulatory authorities continue to develop new competitive market structures and consider retail wheeling programs, we believe that the tests and mechanisms we have provided in this Rule will accommodate both Federal and state interests and will help provide jurisdictional certainty to market participants.

*21628 *J. Stranded Costs*

1. Justification for Allowing Recovery of Stranded Costs

In the Supplemental Stranded Cost NOPR, the Commission noted that the Open Access Rule would give a utility's historical wholesale customers greatly enhanced opportunities to reach new suppliers.[FN553] This would affect the way in which utilities have recovered costs under the traditional regulatory system that, on the one hand, imposed an obligation to serve,[FN554] and, on the other hand, permitted recovery of all prudently incurred costs. We noted that if customers leave their utilities' generation systems without paying a share of these costs, the costs will become stranded unless they can be recovered from other customers. The Commission stated in the NOPR that we must address the costs of the transition to a competitive industry by allowing utilities to recover their legitimate, prudent and verifiable stranded costs simultaneously with any final rule we adopt requiring open access transmission.[FN555]

Comments

Virtually all of the investor-owned utility commenters as well as commenters representing state commissions and other constituencies support the NOPR's premise that stranded costs can be created when a customer switches suppliers. They endorse the proposal to allow the recovery of legitimate and verifiable stranded costs.[FN556] Numerous commenters also support the Commission's proposal to link stranded cost recovery with open access tariffs. These commenters agree that the recovery of stranded costs is critical to the successful transition of the industry to an open transmission access, competitive industry.[FN557] Commenters such as EEI and NU submit that open access and stranded cost recovery should be implemented simultaneously; that unbundled transmission service should not be required until a stranded cost recovery mechanism is in place. Some commenters propose that if the full recovery of stranded costs is disallowed as a result of rehearing or judicial review, utilities that have filed open access transmission tariffs should be permitted to withdraw them, or the Commission should otherwise reconsider its rule on open access transmission in light of such a reversal.[FN558]

Commenters representing the financial community reiterate their strong support for the full recovery of stranded costs, noting that the prospect of not recovering stranded costs could erode a utility's ability to attract capital which, in turn, could impede the long-term goal of achieving competitive wholesale markets.[FN559] Several commenters also argue that stranded cost recovery is economically efficient and is necessary to ensure parity among competitors and to avoid uneconomic bypass.[FN560]

The commenters that oppose allowing utilities to recover legitimate and verifiable stranded costs repeat many of the arguments that were raised in response to the initial Stranded Cost NOPR. For example, a number of commenters argue that the risk that a utility could lose customers (and thereby incur stranded costs) is not a new phenomenon created by regulatory and statutory initiatives that utilities could not have anticipated.[FN561] Some commenters argue that there was never an implied obligation to serve at wholesale.[FN562] According to TDU Systems, monopoly power, not regulatory obligation, has kept wholesale customers captive over the years.

Other commenters argue that allowing the recovery of stranded costs would make it uneconomic for customers to seek alternative sources of power and that the prospect of liability for and protracted litigation over stranded cost claims would create paralyzing uncertainty for customers, uncertainty that may dissuade them from taking advantage of new opportunities in the wholesale power market.[FN563] Some commenters also argue that stranded cost recovery would be a disincentive to efficient operation by affording the greatest protection to utilities that made the worst investment decisions.[FN564]

Commenters also argue that the scope of the proposed rule is overbroad; that stranded cost recovery should be allowed, if at all, on a case-by-case basis; that there should be no presumption that every utility will experience stranded costs; and that utilities should not be allowed to recover 100 percent of prudently incurred stranded costs.[FN565]

Several commenters suggest that there is no factual basis for the stranded cost rule, citing a lack of evidence of a wholesale stranded cost problem.[FN566] TDU Systems refers to a Resource Data International study that shows that, of $114 billion in potential investor-owned utility stranded investment, only $10.4 billion is associated with wholesale transactions.[FN567] Others submit that the *21629 Commission should obtain more current data concerning the magnitude of potential stranded cost recovery before issuing the final rule.[FN568] In reference to the statement in the Supplemental NOPR that the Commission will continue to gather information on the magnitude of potential stranded costs,[FN569] DE Muni states that the Commission must commit to making public all the data it obtains so that all can evaluate the impact of the recovery of stranded costs on an ongoing basis.

NRRI submits that the Commission has drawn the wrong conclusion from its natural gas industry experience. According to NRRI, pipelines were "caught in an unusual transition" by changes caused by Congress and the Commission. In the case of the electric industry, NRRI submits that although there are uneconomic wholesale power contracts, the Commission is not responsible for this situation.[FN570]

Several commenters suggest that the Commission condition a utility's ability to recover stranded costs upon the utility agreeing to take certain actions (such as reducing environmental effects [FN571] or ensuring the payment of costs that are stranded if the utility commences direct service to an end-use customer that was previously a wholesale customer of a transmission dependent utility [FN572]), or agreeing to refrain from certain actions (such as seeking unilaterally to terminate or modify IPP contracts).[FN573] CCEM proposes that open access, conversion rights, and divestiture should each be a precondition to a utility's eligibility for any stranded cost recovery. VT DPS submits that, if the Commission adopts a stranded cost rule, it should limit utility stranded cost claims to those cases where the utility can demonstrate that its costs have been rendered unrecoverable as a direct result of the final rule.[FN574]

A number of commenters object that the proposed rule contains no provisions for non-transmission-owning utilities to collect stranded costs.[FN575] Illinois Municipal Electric Agency asks the Commission to consider providing a forum for municipals to recover stranded costs from their customers under the same guidelines as investor-owned utilities. Recognizing that the FPA gives the Commission no general jurisdiction over municipalities for purposes of rate regulation,[FN576] Illinois Municipal Electric Agency argues that the FPA nevertheless does not prevent the Commission from providing a forum for municipalities that may experience stranded costs as a result of new federal regulations. NE Public Power District, RUS, and rural electric cooperative commenters object that the NOPR gives public utilities a greater chance than other transmitting utilities to recover stranded costs from departing customers by offering public utilities two avenues of recovery (an exit fee under a power sales contract or a transmission surcharge) but offering other transmitting utilities only one avenue (a transmission surcharge).[FN577]

PA Munis objects that the Commission's proposal to impose stranded costs only on wholesale requirements customers (and not on other wholesale customers) is unduly discriminatory and counter to the goals of the Open Access NOPR. It submits that the Commission's proposal, by subjecting a wholesale requirements customer to increased transmission rates for stranded costs not levied on other wholesale customers, is indistinguishable in substance from the pre-Order 436 plan held to be discriminatory in Maryland People's Counsel v. FERC.[FN578]

ELCON and others[FN579] urge the Commission to clarify that stranded costs do not arise when a customer leaves a system because its plant becomes uneconomic or the customer wishes to co-generate or self-generate. They note that "[t]hese alternatives have always existed and do not arise from new opportunities for wholesale and retail wheeling."[FN580]

Commission Conclusion

We reaffirm our preliminary determination that the recovery of legitimate, prudent and verifiable stranded costs should be allowed. Having considered the arguments raised by the commenters that oppose stranded cost recovery, we continue to believe that utilities that entered into contracts to make wholesale requirements sales under an entirely different regulatory regime should have an opportunity to recover stranded costs that occur as a result of customers leaving the utilities' generation systems through Commission-jurisdictional open access tariffs or FPA section 211 orders,[FN581] in order to reach other power suppliers. As we indicated in the Supplemental Stranded Cost NOPR, we do not believe that utilities that made large capital expenditures or long-term contractual commitments to buy power years ago should now be held responsible for failing to foresee the actions this Commission would take to alter the use of their transmission systems in response to the fundamental changes that are taking place in the industry.[FN582] We will not ignore the effects of recent significant statutory and regulatory changes on the past investment decisions of utilities.[FN583] While, as some commenters point out, there has always been some risk that a utility would lose a particular customer, in the past that risk was smaller. It was not unreasonable for the utility to plan to continue serving the needs of its wholesale requirements customers and retail customers, and for those customers to expect the utility to plan to meet future customer needs. With the new open access, the risk of losing a ***21630** customer is radically increased. If a former wholesale requirements customer or a former retail customer uses the new open access to reach a new supplier, we believe that the utility is entitled to recover legitimate, prudent and verifiable costs that it incurred under the prior regulatory regime to serve that customer.[FN584]

We learned from our experience with natural gas that, as both a legal and a policy matter, we cannot ignore these costs. During the 1980s and early 1990s, the Commission undertook a series of actions that contributed to the impetus for restructuring of the gas pipeline industry. The introduction of competitive forces in the natural gas supply market as a result of the Natural Gas Policy Act of 1978[FN585] and the subsequent restructuring of the natural gas industry left many pipelines holding uneconomic take-or-pay contracts with gas producers. When the Commission initially declined to take direct action to alleviate that burden, the U.S. Court of Appeals for the District of Columbia Circuit faulted the Commission for failing to do so.[FN586] The court noted that pipelines were "caught in an unusual transition" as a result of regulatory changes beyond their control.[FN587]

As we stated in the Supplemental NOPR, the court's reasoning in the gas context applies to the current move to a competitive bulk power industry. Indeed, because the Commission failed to deal with the take-or-pay situation in the gas context, the court invalidated the Commission's first open access rule for gas pipelines. Once again, we are faced with an industry transition in which there is the possibility that certain utilities will be left with large unrecoverable costs or that those costs will be unfairly shifted to other (remaining) customers. That is why we must directly and timely address the costs of the transition by allowing utilities to seek recovery of legitimate, prudent and verifiable stranded costs. At the same time, however, this Rule will not insulate a utility from the normal risks of competition, such as self-generation, cogeneration, or industrial plant closure, that do not arise from the new availability of non-discriminatory open access transmission. Any such costs would not constitute stranded costs for purposes of this Rule.

We are issuing the Stranded Cost Final Rule simultaneously with the Open Access Final Rule because we believe that the recovery of legitimate, prudent and verifiable stranded costs is critical to the successful transition of the electric industry to a competitive, open access environment. We believe that our decision today will be upheld by the courts. While the D.C. Circuit is still considering the various appeals of Order No. 636,[FN588] it has already upheld, in at least two instances, our ultimate decision to allow the recovery of costs stranded in the transition to a competitive natural gas industry.[FN589] As a result, we reject the suggestions of some commenters that a utility's obligation to comply with the provisions of the Open Access Final Rule should be conditioned upon final court approval of the Stranded Cost Final Rule. We also decline otherwise to condition a utility's ability to recover its stranded costs. As described in greater detail in Section IV.J.8, if a utility can make the necessary evidentiary showings, it will be eligible for stranded cost recovery.

With regard to the magnitude of potential wholesale stranded costs, as the Supplemental Stranded Cost NOPR recognizes, the level may be small relative to that of retail stranded costs. Nevertheless, wholesale costs may be stranded as a result of open access transmission. Because the significance of such costs to the utilities that would face them may be great (and the prospect of not recovering such costs could erode utilities' ability to attract capital and be very detrimental to a diverse array of utility shareholders), we believe that we have a responsibility to allow for the recovery of such costs.

We disagree with the commenters who contend that this Rule would discriminate against certain segments of the industry, such as non-transmission-owning utilities (who would not be allowed to collect stranded costs) or wholesale requirements customers (who would be subject to stranded cost charges while other wholesale customers would not). These commenters misconstrue the purpose of this Rule and the nature of the stranded costs for which this Rule would allow recovery. This rule is designed to address a new and specific problem: The fact that a utility that historically has supplied bundled generation and transmission services to a wholesale requirements customer and incurred costs to meet reasonably expected customer demand may experience stranded costs when its customer is able to reach a new generation supplier due to the availability of open access transmission. This rule proposes a solution to that problem by allowing the recovery of legitimate, prudent and verifiable costs incurred by a utility to provide service to a wholesale requirements customer that subsequently becomes, in whole or in part, an unbundled wholesale transmission services customer of the utility. The opportunity for extra-contractual wholesale stranded cost recovery is allowed for only a discrete set of requirements contracts for which the utility can demonstrate that it had a reasonable expectation of continuing service, as well as for retail-turned-wholesale situations in which the utility satisfies the necessary evidentiary criteria. Thus, the fundamental premise of this rule—namely, that a utility should have an opportunity to recover reasonably-incurred costs that arise because open access use of the utility's transmission system enables a generation customer to shop for power—would not apply to a non-transmission-owning utility that, by definition, has no transmission by which its generation customer can escape to another supplier.

The same historical relationship discussed above, including the expectation of continued service, justifies imposing the stranded costs covered by this rule on wholesale requirements customers only (not on non-requirements customers that contract separately for transmission services to deliver their purchased power). Requirements customers historically were long-term customers who typically did not expect to take service from other suppliers. Utilities thus assumed they would continue ***21631** serving these customers and may have made significant investments based on that long-term expectation. In contrast, utilities did not (and do not today) generally make investments for short-term economy-type transactions. Rather, such transactions were entered into only when the utility temporarily had available capacity or energy that could be provided to the buyer at a price lower than the buyer's decremental cost. The utility was not obligated in any way—either explicitly or implicitly—to provide for the needs of non-requirements customers. Because coordination transactions were not the cause of stranded investment decisions, it would be inappropriate to allocate such costs to non-requirements customers.

Further, although some commenters object that the Rule would give public utilities a greater opportunity than other transmitting utilities to recover stranded costs, our jurisdiction over transmitting utilities that are not also public utilities is limited. If the selling utility under an existing contract is a transmitting utility that is not also a public utility, its wholesale requirements contracts are not subject to this Commission's jurisdiction. Thus, we can allow such a transmitting utility to recover stranded costs only through Commission-jurisdictional transmission rates under sections 211 and 212 of the FPA. Nevertheless, in the context of a specific section 211 case, we would expect to apply similar principles to the extent possible to assure full stranded cost recovery. We also encourage such transmitting utilities to negotiate mutually agreeable stranded cost provisions with their customers.

2. Cajun Electric Power Cooperative, Inc. v. FERC[FN590]

In the Supplemental Stranded Cost NOPR, the Commission made a preliminary finding that the Cajun court decision does not bar the recovery of stranded costs as proposed in the NOPR and set forth our reasoning in support of that finding.[FN591]

Comments

Various commenters contend that the proposal to permit recovery of stranded costs at all, or particularly through transmission rates of departing customers, fails to address the Cajun court's concerns.[FN592] These commenters repeat many of the same arguments previously raised in this proceeding, which we have already addressed. Some commenters argue that including generation-based stranded costs in transmission rates is an anticompetitive tying arrangement and that Cajun compels the Commission to abandon this aspect of its stranded cost proposal or, at a minimum, to explain how the chosen method of recovery differs from that remanded in Cajun.[FN593]

Several commenters[FN594] question whether the NOPR's stranded cost provisions would undermine the "meaningful" access to alternative suppliers referenced by the Cajun court.[FN595] For example, Arkansas Cities asserts that the Commission has failed to address whether a transmitting utility retains market power over transmission even after imposition of an open access tariff. It contends that this question is vital to determining whether imposition of stranded costs would interfere with a wholesale transmission customer's meaningful access to other power suppliers.

Some commenters also submit that the proposed procedures for a customer to obtain an estimate of its stranded cost liability are inadequate because they do not ameliorate the uncertainty confronting the customer, which was a concern of the court in Cajun. They suggest that a customer would still face the prospect of litigation concerning whether a proposed stranded cost charge is appropriate.[FN596]

Other commenters argue that Cajun requires a trial-type evidentiary hearing before stranded costs may be recovered. They question whether the Commission's generic proposals on open access and the Commission's statements about the need to recover stranded costs are adequate.[FN597] ELCON references the Cajun court's statement that "if the Commission is wrong at the outset concerning the possibility of legitimate stranded investment cost, it is not fair or reasonable to create such a mechanism for recovery."[FN598] ELCON submits that the factual record does not demonstrate any significant wholesale stranded cost problem and, as a result, a final rule allowing recovery of such costs would not be "fair or reasonable."

Many other commenters, in contrast, believe that the NOPR is distinguishable from the case that was before the court in Cajun and that the Commission has fully addressed the Cajun court's concerns. According to the Coalition for Economic Competition, this proceeding is very different from the Cajun proceeding because the proposed rule would not automatically permit utilities to charge market-based rates. The Coalition for Economic Competition states that in the absence of generic market-based rate authorization, there is no basis in Cajun for barring the recovery of stranded investment in transmission tariffs.[FN599]

A number of commenters agree with the Commission that the Cajun court was concerned with the need for a more complete explanation of the basis for stranded cost recovery and the mechanism selected for such recovery. These commenters believe that the NOPR provides both the evidentiary record for addressing these concerns on a generic basis and the opportunity for all participants to present evidence and arguments.[FN600]

Noting the Cajun court's concern as to whether the wholesale customer in that case had "meaningful" access to alternative suppliers, a number of commenters agree that the Commission, through the open access provisions of the NOPR, is in fact providing wholesale customers meaningful, reasonable access to alternative suppliers.[FN601]

As evidence that the Cajun court was concerned with inadequate explanation and procedures and did not find that stranded costs could never be justified, several commenters point out that the Cajun court did not mention the D.C. Circuit's landmark decision in AGD, which strongly supports stranded cost ***21632** recovery.[FN602] For example, Coalition for Economic Competition suggests that construing Cajun to hold that stranded cost recovery is always anticompetitive would be at odds with AGD and other decisions that have upheld the Commission's policy of allowing recovery of the costs of the transition to competitive markets.[FN603]

Numerous commenters also support the Commission's conclusion that stranded cost recovery through transmission rates is not a tying arrangement.[FN604] Among other things, these commenters argue that a tying claim requires that the defendant force the sale of a separate product with the sale of a product over which it has market power, and that here there is no second product being tied to transmission. Several commenters also suggest that, in any event, stranded cost recovery as proposed in the NOPR would be considered a legitimate business justification under the antitrust laws.[FN605] Com Ed explains that the Commission, as part of its effort to enhance competition in generation by opening up the transmission network, is avoiding placing on utilities the entire burden of the stranded costs resulting from their past regulatory obligations; it is not permitting utilities to maintain a monopoly of power sales.

Commission Conclusion

We reaffirm that we do not interpret the Cajun court decision as barring the recovery of stranded costs. The court in that case did not bar stranded cost recovery, as some commenters suggest; it instead found that the Commission had not provided adequate proceedings and had not fully explained its decision. The Commission had failed to hold an evidentiary hearing concerning whether the inclusion of a stranded cost recovery provision in a particular utility's transmission tariff, along with other provisions in the tariff, resulted in the adequate mitigation of Entergy's market power so as to justify market-based rates. The court also found that the Commission had failed to explain adequately its approval of the stranded cost provision, among other provisions. In contrast, as discussed below, we have addressed in this consolidated proceeding (the Stranded Cost NOPR, the Supplemental Stranded Cost NOPR, the Open Access NOPR, and the Open Access/Stranded Cost Final Rule) all of the Cajun court's concerns.

Our interpretation of Cajun is bolstered by a recent opinion of the Court of Appeals for the D.C. Circuit (the same circuit that decided Cajun) that confirms the validity of Commission imposed stranded cost recovery mechanisms in the transition to competitive markets. In Western Resources, Inc. v. FERC,[FN606] the court affirmed the Commission's decision to allow the recovery of costs stranded in the transition of the natural gas industry to a competitive market.[FN607] We believe that, by this decision, the court has again affirmed the Commission's ability to allow stranded cost recovery, as long as we follow adequate procedures and explain our decision.[FN608]

We are providing in this proceeding the evidentiary record to support our decision to allow the recovery of legitimate, prudent and verifiable stranded costs on a generic basis. We also are ensuring the "meaningful" access to alternative suppliers that was identified as a concern of the Cajun court. The Open Access Final Rule is designed to attack one essential element of market power—namely, control over transmission access. The standard we are adopting for transmission service is far stricter than the standard we used at the time Cajun was decided; we now require non-discriminatory open access transmission, as well as a code of conduct and non-discriminatory sharing of transmission information (OASIS). The collective effect of these actions is that public utilities that own, control or operate interstate transmission facilities will not be able to favor their own generation and will have to compete on an equal basis with other suppliers.[FN609] All public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce will have tariffs on file that offer to any eligible customer any transmission services that the public utility could provide to itself, and under comparable terms and conditions.

We note that the Cajun court identified several provisions in Entergy's proposed tariff as potentially restraining competition: Entergy's retention of sole discretion to determine the amount of transmission capability available for its competitors' use; [FN610] the point-to-point service limitation;[FN611] the failure to impose reasonable time limits on Entergy's response to requests for transmission service;[FN612] and Entergy's reservation of the right to cancel service in certain instances,[FN613] even where a customer had paid for transmission system modifications.[FN614] These types of provisions, which have the potential to restrain competition, will not be allowed under the Open Access Rule. On the contrary, the Final Rule pro forma tariff contains terms and conditions to ensure the provision of non-discriminatory transmission service. In addition, the requirements that a public utility take service under its own tariff, adopt a non-discriminatory transmission information network, and separate power marketing and transmission functions further ensure non-discrimination and remove constraints to fair competition. Thus, the nondiscriminatory open access ***21633** transmissionthat is the hallmark of this Rule is designed to ensure meaningful access to alternative suppliers and goes far beyond that which was offered in the transmission tariff that was under review in Cajun.

We also have addressed the Cajun court's concern over the method of recovery. In that case, Entergy proposed to include a charge in the departing customer's transmission rate to recover its stranded investment costs. The court said that this might constitute an anticompetitive tying arrangement.[FN615] As we explained in the Supplemental NOPR, the stranded cost recovery procedure we prescribe in this Rule is a transitional mechanism only that is intended to enable utilities to recover costs prudently incurred under a different regulatory regime. The purpose and effect of the stranded cost recovery mechanism that we approve in this Rule is to facilitate the transition to competitive wholesale power markets. Although we recognized in the Supplemental NOPR that stranded cost recovery may delay some of the benefits of competitive bulk power markets for some customers, such transition costs must nevertheless be addressed at an early stage if we are to fulfill our regulatory responsibilities in moving to competitive markets. The stranded cost recovery mechanism that we direct here is a necessary step to achieve pro-competitive results. In the long term, the Commission's rule will result in more competitive prices and lower rates for consumers.

The Commission's approach also is consistent with the traditional regulatory concept of cost causation. We do not believe it is an illegal tying arrangement to hold a customer accountable for the consequences of leaving an incumbent supplier if, under our rules, the incumbent supplier must show a reasonable expectation of continuing service before it can recover stranded costs from the customer.

Further, in response to the Cajun court's concern that the Commission had failed in that case to explain adequately its approval of the stranded cost provision and other provisions, we have provided in this proceeding a detailed explanation of the fundamental industry and regulatory changes that have given rise to the potential for stranded costs; the transitional nature of stranded costs; the critical need to deal with these costs in order to reach more competitive wholesale markets; and the consumer benefits that will result from competitive generation markets. We also have provided a detailed explanation of the terms and conditions in the Final Rule pro forma tariff that will meet the non-discriminatory open access service requirement.

Several commenters (and the Cajun court) express concern for the need to provide as much certainty as possible for departing customers concerning their potential stranded cost obligation. Without some certainty, customers may be unable to shop for alternative suppliers. In response to these concerns, we have modified the stranded cost recovery mechanism to include a formula for calculating a departing customer's potential stranded cost obligation. As discussed in greater detail in Section IV.J.9, the revenues lost formula is designed to provide certainty for departing customers and to create incentives for the parties to address stranded cost claims between themselves without resort to litigation.

We conclude that we have fully explained our decision to allow the recovery of legitimate, prudent and verifiable costs that are stranded in the transition to competitive wholesale bulk power markets. We also have provided ample opportunity for all concerned to present arguments and evidence on the issue. Further, we have significantly strengthened our open access requirements to ensure mitigation of transmission market power. Thus, we have fully addressed the concerns of the Cajun court.

3. Responsibility for Wholesale Stranded Costs (Whether To Adopt Direct Assignment to Departing Customers)
In the Supplemental Stranded Cost NOPR, the Commission made a preliminary finding that direct assignment of stranded costs to the departing wholesale generation customer is the appropriate method for recovery of such costs.[FN616]

Comments
Numerous parties representing all constituencies support direct assignment of stranded costs to the departing generation customer.[FN617] These commenters argue, among other things, that direct assignment is consistent with the cost causation principle and preferable to increasing the delivered price of electricity to a whole region through the imposition of a wires charge, and that recovery of stranded costs from remaining customers would not be in the public interest. Several state commenters seek assurance from the Commission that native load customers will be held harmless from stranded costs resulting from other customers leaving the system.[FN618] KY Com submits that the possible results of a broader assessment of stranded costs, with the related uncertainty of its impact on the utilities' cost of capital, is more problematic in the long run than the possibility that the direct assignment of stranded costs would deter customers from shopping for power.

Although TAPS opposes stranded cost recovery in general, it submits that, if the Commission decides to allow recovery, the Commission should directly assign stranded costs and not spread them across the board to all transmission users.

Several commenters also oppose any allocation of stranded cost liability to shareholders.[FN619]

Some commenters state that direct assignment of stranded costs sends the correct pricing signals during the transition to a competitive regime. For example, Electric Consumers Alliance states that a wholesale customer should be able to obtain power elsewhere, but that the motive to do so should not be to escape responsibility for sunk investments made on its behalf. El Paso submits that failure to make the departing generation customer liable for stranded cost recovery would create a "first-off" incentive; the customers that leave the system first would not suffer from higher future rates designed to recover prudently incurred costs from the reduced base of remaining customers.

Some commenters support direct assignment but oppose recovery of stranded costs through transmission rates. These commenters prefer an exit fee or lump-sum approach that would reflect cost causation in an unbundled fashion.[FN620] DOJ maintains that a ***21634** transmission adder is analogous to an excise tax and that the excise tax approach would distort pricing signals and customers' decisions on the use of electric power. It submits that the lump-sum approach, on the other hand, would establish a fixed, sunk liability that would not depend upon how much transmission service the departing customer takes in the future.[FN621]

Other commenters oppose direct assignment as being inconsistent with wholesale competition.[FN622] They argue that placing all of the responsibility for stranded costs on departing generation customers would discourage customers from switching to other generation providers and would thereby inhibit competition.[FN623] Some commenters also assert that departing generation customers are not the sole "cause" of stranded costs.[FN624] VT DPS contends that direct assignment cannot be reconciled with the Commission's refusal to allow the imposition of exit fees by gas pipelines when their wholesale customers depart.[FN625]

Some commenters support spreading the burden of stranded costs broadly among departing customers, shareholders, and remaining wholesale customers on the basis that it would be equitable for all industry stakeholders to share both the benefits and the costs of the transition to competition.[FN626]

Others support spreading the costs to all customers through, for example, a meter charge to all utilities (to be passed on to customers), a one-time charge across the total market base, an access fee on the transmission system, or a component of transmission rates.[FN627] Nordhaus proposes a uniform national tax on all customers, at a rate that declines over time in a predetermined manner. He submits that this approach would remove "gaming" between utilities and potential exiters, would ensure that the stranded costs are not disproportionately loaded on price-sensitive demanders (that is, exiting customers), and would gradually disappear over time in a predictable fashion, thereby increasing the predictability of the new market.

PA Munis disputes the Commission's assertion in the Supplemental Stranded Cost NOPR that there is no compelling reason to assess costs broadly. It argues that a broad-based recovery mechanism that distributes uneconomic stranded costs to all power users would minimize the competition-inhibiting aspects of the Commission's proposed surcharge on departing generation customers. In a similar fashion, NSP states that across-the-board recovery from all users of the grid would recognize the societal benefits to be achieved from the transition to a competitive bulk power market and would reflect precedent set during the move to competition in the natural gas and telephone industries. It submits that the cost per service unit would be lower than exit fees assigned to particular customers and would eliminate the need for detailing stranded cost exposure for each customer contemplating leaving the system.

FTC submits that some investments that now appear as stranded costs may have been intended to benefit customers over a wider area than a single utility. It suggests that national regional assessment methods could recover stranded costs undertaken to benefit these wider groups of customers.

We also received comments suggesting that less than full recovery of stranded costs should be allowed. A number of commenters urge the Commission to require some shareholder liability for stranded cost recovery to give utilities an incentive to mitigate.[FN628] Several of these commenters assert that utility shareholders should be required to pay a portion of any stranded costs (such as 25-50 percent) because at least some of the responsibility for stranded costs lies with poor business decisions by utility management.[FN629] Occidental Chemical proposes that the Commission grant utilities a "presumption of prudence" in return for requiring them to absorb a minimum of 25 percent (up to 50 percent) of stranded costs, citing as support the Commission's precedent in the natural gas industry.

Commission Conclusion
We reaffirm our decision that direct assignment of stranded costs to the departing wholesale generation customer through either an exit fee[FN630] or a surcharge on transmission is the appropriate method for recovery of such costs. We believe it is appropriate that the departing generation customer, and not the remaining generation or transmission customers (or shareholders), bear its fair share of the legitimate and prudent obligations that the utility undertook on that customer's behalf.

In reaching this decision, we have carefully weighed the arguments supporting direct assignment of stranded costs against those supporting a more broad-based approach, such as spreading stranded costs to all transmission users of a utility's system. ***21635** Recognizing that each approach has advantages and disadvantages, we conclude that, on balance, direct assignment is the preferable approach for both legal and policy reasons.

One of the main reasons to adopt direct assignment of stranded costs is that direct assignment is consistent with the well-established principle of cost causation, namely, that the party who has caused a cost to be incurred should pay it. Direct assignment of stranded costs to departing generation customers is particularly appropriate given the nature of the stranded cost recovery mechanism contained in this Rule, which links the incurrence of stranded costs to the decision of a particular generation customer to use open access transmission to leave the utility's generation system and shop for power, and which bases the prospect of stranded cost recovery on the utility's ability to demonstrate that it incurred costs with the reasonable expectation that the customer would remain on its generation system.

A broad-based approach, in contrast, would violate the cost causation principle by shifting costs to customers (such as transmission users of the utility's system) that had no responsibility for stranding the costs in the first place. In addition, if the Commission were to adopt a broad-based approach, it would have to determine whether to base the transmission surcharge on all users of a utility's transmission system on a one-time, up-front estimate of stranded costs (that is, each utility claiming stranded costs would make a one-time, comprehensive determination of stranded costs for the utility as a whole) or on an as-realized basis (the surcharge would be based on actual customer departures and would be adjusted each time a customer departs). Each option would have disadvantages that are not present in the direct cost causation approach we are adopting.

For example, a major disadvantage of an up-front, broad-based transmission surcharge is that it in effect would charge customers for costs before the costs are incurred (i.e., before customers have even decided to leave the utility's generation system) and could charge for costs that may never be incurred (e.g., some customers may decide to stay on the utility's system as requirements customers). The other option, a broad-based transmission surcharge that would be adjusted as customers leave the utility's system, also has disadvantages. While this option might recover stranded costs that are closer to the actual amount incurred by the utility, it could produce variability in transmission rates every time stranded costs from a newly-departed customer are included in the transmission surcharge and, in turn, could possibly hamper efficient power supply choices and efficient generator location decisions. These disadvantages are not present in the direct assignment approach.

Direct assignment will result in a more accurate determination of a utility's stranded costs than would an up-front, broad-based transmission surcharge. This is because the stranded cost for any customer is finally determined only if that customer actually leaves a utility. Moreover, there is no stranded cost unless the then-current market price of power for the period that the utility reasonably expected to continue serving the customer is below the utility's cost. Thus, because the circumstances of each departing customer will be known, the amount of any stranded cost liability can be determined with reasonable accuracy. Further, if a customer does not leave the utility or leaves at some future time when the utility's costs are competitive, the issue need not be addressed.

On this basis, the direct assignment approach is more suited to the recovery of stranded costs as defined in this Rule (including the reasonable expectation standard and open access transmission causation requirement) than is a broad-based approach. We expect that a utility would have difficulty estimating in advance all of its stranded costs for purposes of an up-front, broad-based transmission surcharge. In the face of this uncertainty, the utility's best strategy likely would be to try to recover through the broad-based surcharge as much of its uneconomic assets as possible by claiming that all of its wholesale customers are likely to depart and to leave large stranded costs. In this regard, the broad-based approach would provide an incentive for a utility to try to recover the costs of all of its uneconomic assets whether or not they were prudently incurred. This is in contrast to what this Rule provides, which is for recovery of only those legitimate, prudent and verifiable costs that were incurred on behalf of a specific customer based on a reasonable expectation that the utility would continue to serve the customer and that are stranded when the customer departs the utility's generation system by using the utility's open access transmission.

The direct assignment approach also can be readily applied to both wholesale and retail-turned-wholesale departing customers. It also can be adapted for retail customers. Further, it works for costs stranded by a section 211 order requiring either a public utility, or a transmitting utility that is not also a public utility, to provide transmission service. However, this is not the case for a broad-based approach, particularly an up-front, broad-based approach. Assuming that a principal motivation for an up-front, broad-based approach would be to recover all of a utility's stranded costs as quickly as possible, retail-turned-wholesale stranded costs nevertheless are not susceptible of being collected on an up-front basis. It is not possible to make a realistic up-front estimate of costs stranded by municipalizations that may occur in the future. Thus, even if we were to adopt an up-front, broad-based approach for recovering costs that are stranded when wholesale requirements customers use their former supplier's transmission system to reach a new supplier, retail-turned-wholesale stranded costs would have to be identified as they occur and the stranded cost surcharge on transmission users adjusted accordingly. Similarly, the broad-based approach is not easily adaptable to transmitting utilities that are not also public utilities. It is doubtful that, in establishing the rate for a section 211 applicant, the Commission could also set transmission surcharges for customers that were not section 211 applicants; this is what a broad-based approach, in effect, would require us to do.

Direct assignment by means of an exit fee or a transmission surcharge that is not dependent on any subsequent power or transmission purchases by the customer is also an economically efficient way to collected stranded costs. The customer may make a lump-sum stranded cost payment, amortize the lump-sum payment, or spread the payment as a surcharge in addition to its transmission rate. The total amount of stranded costs that the directly-assigned customer ultimately pays would not depend on how much transmission service it takes and thus would not influence the customer's subsequent transmission purchase decisions.

With a broad-based surcharge (which could be demand- or usage-based), on the other hand, the surcharge for transmission users would depend on how much transmission service the users take. A broad-based approach also would be inefficient as it would raise the price of transmission service for all customers, thereby potentially cutting off some beneficial power trading that would otherwise occur for all unbundled transmission customers. The surcharge also could convert some profitable existing power purchase contracts into unprofitable contracts. In ***21636** addition, it could reduce economy trading because the surcharge would be added to the price of economy transmission. In this manner, a broad-based surcharge would constitute a cross-subsidy that could distort the market.

We recognize that direct assignment is not without its potential drawbacks. For example, when compared to an up-front, broad-based transmission surcharge approach, direct assignment may entail a longer stranded cost recovery period. The transition period for stranded cost recovery under a direct assignment approach would depend on the length of the remaining terms of the wholesale requirements contracts for which this Rule provides an opportunity for recovery (contracts executed on or before July 11, 1994 that do not contain an exit fee or explicit stranded cost provision).

On the other hand, a broad-based approach could identify and recover stranded costs earlier than the direct assignment approach; recovery of stranded costs for all of a utility's wholesale requirements customers could begin as soon as the utility's up-front stranded cost amount for departing wholesale customers is determined (through litigation or settlement). However, this potential advantage of a broad-based approach (the shorter transition period) is outweighed by what we believe to be a serious infirmity, namely, the possibility that the broad-based transmission surcharge could end up including costs that have not yet been incurred and may never be incurred.

In addition, another potential drawback to the direct assignment approach is that the departing generation customer may see little or no savings in the short-term by switching power suppliers once its stranded cost exit fee is added to its lower power price from a new supplier. Direct assignment may leave the customer uncertain about the benefits of shopping for power because of the customer's potential stranded cost liability and, in turn, may bias the customer toward staying with its existing power supplier.[FN631]

In the case of a broad-based approach, in contrast, much of the customer's direct assignment stranded costs are spread to others through a transmission surcharge. As a result, the departing generation customer's power cost savings may more than offset the customer's stranded cost transmission surcharge. The customer may therefore see earlier power cost savings if a broad-based approach were adopted.[FN632] Once again, however, we believe that this potential benefit to a broad-based approach is outweighed by a significant countervailing disadvantage. In particular, the potential power cost savings to the departing generation customer would be realized only by shifting costs (that are directly attributable to the departing generation customer) to the other users of the utility's transmission system. We believe that this negative aspect of a broad-based approach—its violation of the cost causation principle—is too great a price to pay for allowing a departing generation customer to realize power cost savings as early as possible.

Thus, we recognize that under direct assignment, it is possible that some customers may not be able to afford to leave as soon as they would like. This in turn could mean that lower cost suppliers would not be able to make sales to those customers as soon as they would like. However, this would occur only during a transition period, and it would ensure that, consistent with strict cost causation principles, the burden of these transition costs is not unfairly spread to other customers. Once the existing uneconomic assets and contracts are behind us, all wholesale customers will be better able to shop for power and reap the long-term benefits of competitive supply markets.

Although this direct assignment approach is different from the approach taken in the natural gas industry, we believe that the difference is justified. The transition of the electric industry to an open transmission access, competitive industry (including our proposal to allow an opportunity for extra-contractual recovery of stranded costs associated with a discrete set of wholesale requirements contracts) is different in a number of respects from the natural gas industry's transition to open access transportation service by interstate natural gas pipelines. The gas industry underwent a long period of open access transition, starting with Order No. 436 in 1985 and culminating with Order No. 636 in 1992. In the gas context, prior to addressing potential stranded costs, the Commission in Order No. 436 allowed customers receiving bundled gas sales and transportation service from a pipeline the option to convert to transportation-only service, or to reduce their contract demand for gas service, before the termination of their contracts with the pipeline.[FN633] As a result, most of the former bundled customers of the pipeline had already departed the pipeline's sales service before the Commission addressed the recovery of take-or-pay costs in Order Nos. 500 and 528. In addition, by the time that the Commission addressed the remaining transition costs in Order No. 636, the commodity or wellhead natural gas market was already competitive and the majority of gas was already being sold on an unbundled basis.

Thus, changes in the natural gas industry had progressed to such a point (i.e., the departure of customers from bundled sales) that it was not possible for the Commission to use a strict cost causation approach. We noted in the Supplemental Stranded Cost NOPR that

Many natural gas customers had already left their historical pipeline suppliers' systems. Others had converted from sales and transportation customers to transportation-only customers. Others were in a transition stage having had opportunities to lower their contract demands or otherwise become partial service customers. Significant take-or-pay and other costs had accumulated.[FN634]

Under those circumstances, the Commission determined that it was appropriate to spread the majority of the remaining transition costs associated with take-or-pay and other supply contracts to all customers (both existing and new) using the interstate natural gas transportation system. Moreover, because of the changes in contractual relationships that had already occurred among pipelines and their customers, it was no longer possible for the Commission to follow a strict cost causation approach to recovering take-or-pay costs. The Commission-prescribed remedy for the recovery of transition costs in the natural gas industry thus was tailored to fit the needs of that industry given the stage of development at the time.

However, such a broad-based approach to recovery of natural gas transition costs was an exception to the *21637 time-honored principle that rates should reflect cost causation, and because of this it was necessary for the Commission to justify its departure from that principle. As the court said in K N Energy v. FERC,[FN635] "[i]t has been this Commission's long standing policy that rates must be cost supported. Properly designed rates should produce revenues from each class of customers which match, as closely as practicable, the costs to serve each class or individual customer." In that case, the court found the Commission's departure from cost-causation justified "given the unusual circumstances surrounding the take-or-pay problem, and the limited nature—both in time and scope—of the Commission's departure from the cost-causation principle."[FN636] It continues to be Commission policy to follow the cost-causation principle to the extent possible.

The factors described above are not present in the electric industry. At this time, the vast majority of customers remain on their bundled suppliers' systems and generation is not yet fully competitive. Because the situation facing the electric industry today is different from that which the natural gas industry faced, the Commission must tailor its approach differently. In the case of the electric industry today, we have the opportunity to address the stranded cost recovery issue up front, before customers leave their suppliers' systems. We thus are able to use the cost causation approach that has been fundamental to our regulation since 1935.[FN637]

The Commission disagrees with commenters' arguments that we cannot impose an exit fee to recover stranded costs because we did not do so in the gas context. As discussed in Section IV.J.9, this Rule establishes procedures for providing a potential departing generation customer advance notice (before it leaves its existing supplier) of the stranded cost charge (whether it is to be paid as an exit fee or a transmission surcharge) that will be applied if the customer decides to buy power elsewhere. In the natural gas context, in contrast, the Commission has prohibited pipelines from developing and charging an "exit fee" after a customer had implemented its gas purchase decision, noting that otherwise, the customer would not know in advance the full cost consequences of its nomination decision.[FN638] The "exit fee" that the Commission rejected in El Paso Natural Gas Company[FN639] is also factually distinguishable from the "exit fee" discussed in this rule. In that case, the Commission rejected a pipeline's attempt post-restructuring to impose an "exit fee" on firm transportation-only customers (that were converted sales customers) who in the future elect either to terminate their firm transportation service upon expiration of the service agreement, or to reduce their firm transportation services level by more than 10 percent pursuant to an existing contractual reduction right. Such a scenario is quite different from the limited opportunity for stranded cost recovery provided in this Rule, which is based on a utility's reasonable expectation of continuing generation service to a bundled (sales and transmission) requirements customer.

We also will decline to require a utility seeking stranded cost recovery to shoulder a portion of its stranded costs. Such a requirement would be a major deviation from the traditional principle that a utility should have a reasonable opportunity to recover its prudently incurred costs.[FN640] Although the Commission allowed such an approach with regard to a natural gas pipeline's take-or-pay costs,[FN641] we did so only as an extraordinary measure given the nature of the take-or-pay problem and the prevailing environment at that time. We returned to traditional principles when, in issuing Order No. 636, we authorized pipelines to recover all of their prudently incurred gas supply realignment costs (the costs pipelines incur in realigning, renegotiating, or terminating their portfolio of gas supply contracts to adjust to their sales customers' decisions to exercise their unilateral right under the rule to reduce or end their commodity purchase obligations to the pipelines).[FN642] In the case of the open access transmission required by this Rule, we believe that a utility is entitled to an opportunity to recover all legitimate, prudent and verifiable costs incurred by the utility when the availability of open access transmission enables a requirements customer to reach a new generation supplier.

Although the alternatives of either spreading the stranded costs to all transmission users or requiring the utility shareholders to share the costs with departing customers might enable a wholesale customer to leave sooner than would the direct assignment approach, the departing customer would be able to do so only at the expense of others who had no responsibility for causing the legitimate, prudent and verifiable costs to be incurred. Although we departed from strict cost causation principles in the gas context and required a broad spreading of the costs given the particular circumstances presented by the gas industry's transition to open access, we ultimately returned to the more traditional approach of allowing utilities to recover all of their prudently incurred transition costs in Order No. 636. At this juncture in the evolution of competition in the electric industry we need not make such a departure from cost causation principles; utilities can identify and seek to charge the customers who caused the costs to be incurred in the first place, before those customers leave the utility's generation system. Accordingly, we believe that a broader spreading of the costs to entities who are not responsible for the incurrence of ***21638** the stranded costs would not be equitable.

4. Recovery of Stranded Costs Associated With New Wholesale Requirements Contracts

In the Supplemental Stranded Cost NOPR, the Commission preliminarily concluded that future wholesale contracts must explicitly address the obligations of the seller and buyer, including the seller's obligation to continue to serve the buyer, if any, and the buyer's obligation, if any, if it changes suppliers. We stated that utilities will be allowed stranded cost recovery associated with "new" wholesale requirements contracts (executed after July 11, 1994) only if explicit stranded cost provisions are contained in the contract. We indicated that recovery of wholesale stranded costs associated with any such new contract will not be allowed unless such recovery is provided for in the contract.[FN643] We also stated that a contract that is extended or renegotiated for an effective date after July 11, 1994 becomes a "new" contract for which stranded cost recovery will be allowed only if explicitly provided for in the contract.[FN644]

We also stated that it is not appropriate to impose on a wholesale requirements supplier a regulatory obligation to continue to serve its existing requirements customer beyond the end of the contract term. We proposed to retain the §35.15 prior notice of termination filing requirement only for: (i) All contracts required to be filed under sections 205 and 206 of the FPA that were executed before the effective date of the Final Rule pro forma tariffs; and (ii) any unexecuted contracts that were filed before the effective date of the Final Rule pro forma tariffs. With regard to any power sales contract executed on or after that date, we proposed to no longer require prior notice of termination under §35.15, but to require (for administrative reasons) written notification of the termination of such contract within 30 days after termination takes place. We requested comments on whether this proposal should also be applied to transmission contracts.[FN645]

Comments

Numerous commenters support our preliminary conclusion that new wholesale requirements contracts should explicitly address the obligations of the seller and buyer and that it is not appropriate to impose on wholesale requirements suppliers a regulatory obligation to continue to serve their existing requirements customers beyond the end of the contract term.[FN646] However, Arkansas Cities expresses concern that this could undermine obligations to serve that have been included in certain contracts with utilities. It asks the Commission to state that, unless a utility has undertaken an obligation to serve via contract, there is no obligation to serve beyond the contract term. Arkansas Cities asks the Commission to clarify that contracts establishing an obligation to serve will be enforced.

Several other commenters argue that if a wholesale customer elects to switch suppliers, the previous supplier should be under no obligation to take the customer back onto its system at embedded cost rates.[FN647] Sierra asks the Commission to endorse a host utility's ability to insist on protective contract provisions before reestablishing service, including a predetermined period (such as five years—a commonly-used planning period) before the customer could seek to leave the system again.

A number of commenters support the Commission's proposal to eliminate the prior notice of termination requirement for power sales contracts executed after the date on which the final rule pro forma tariffs become effective.[FN648] Southern states that, because of the opportunities for power purchasers that will exist after the proposed rules take effect, the Commission also should eliminate §35.15 as it applies to old contracts.

Several commenters support eliminating the §35.15 filing requirement for transmission contracts as well.[FN649] This change is needed, some assert, to provide certainty in commercial arrangements in the more competitive environment and as a matter of fairness. CSW suggests that all §35.15 filing requirements for existing contracts (wholesale and transmission contracts) be phased out over three years and that only contracts that expire within three years after the final rule should be subject to the requirement to file a notice of termination.

Nevertheless, several other commenters oppose the Commission's proposal to no longer require prior notice of termination for power sales contracts executed on or after the effective date of the generic tariffs.[FN650] TDU Systems opposes elimination of §35.15 as tantamount to a finding that termination of all contracts is just and reasonable. TDU Systems and NRECA submit that the market power exercised by supplying utilities will not disappear the instant the rule becomes final and that it may be possible for a utility to exercise monopoly power even with regard to "new" contracts. They propose that if the Commission nevertheless decides to allow contract termination under §35.15, the Commission should require a public utility to pay "stranded benefit" costs to former wholesale power customers if the customers show that they had a reasonable expectation that the power sales would continue past the end of the agreement at the prior rate.

Several commenters also oppose eliminating the §35.15 filing requirement for transmission contracts.[FN651] FL Com asserts that because the Commission has imposed an obligation to serve for transmission service, §35.15 should be retained for new and existing transmission contracts.

Commission Conclusion

We reaffirm our preliminary determination that future wholesale requirements contracts should explicitly address the mutual obligations of the seller and buyer, including the seller's obligation to continue to serve the buyer, if any, and the buyer's obligation, if any, if it changes suppliers. As we indicated in the Supplemental Stranded Cost NOPR, now that utilities have been placed on explicit notice that the risk of losing customers through increased wholesale competition must be addressed through contractual means only, they must address stranded cost issues when negotiating new contracts or be held strictly accountable for the failure to do so.

We accordingly will allow recovery of wholesale stranded costs associated with any new requirements contract ***21639** (executed after July 11, 1994) only if explicit stranded cost provisions are contained in the contract. By "explicit stranded cost provision" (for contracts executed after July 11, 1994) we mean a provision that identifies the specific amount of stranded cost liability of the customer(s) and a specific method for calculating the stranded cost charge or rate. For purposes of requirements contracts executed after July 11, 1994 but before the date on which this Final Rule is published in the Federal Register, however, we clarify that a provision that specifically reserved the right to seek stranded cost recovery consistent with what the Commission permits in this Rule (without identifying the specific amount of stranded cost liability of the customer(s) and calculation method) nevertheless will be deemed an "explicit stranded cost provision." However, a provision in a requirements contract executed after July 11, 1994 but before the date on which this Final Rule is published in the Federal Register that merely postpones the issue of stranded cost recovery without specifically providing for such recovery will not be considered an "explicit stranded cost provision." After the date on which this Final Rule is published in the Federal Register, a provision must identify the specific amount of stranded cost liability of the customer(s) and a specific method for calculating the stranded cost charge or rate in order to constitute an "explicit stranded cost provision."

We reaffirm that a requirements contract that is extended or renegotiated for an effective date after July 11, 1994 becomes a "new" requirements contract for which stranded cost recovery will be allowed only if explicitly provided for in the contract.

We also reaffirm our preliminary determination not to impose a regulatory obligation on wholesale requirements suppliers to continue to serve their existing requirements customers beyond the end of the contract term. The only exception to this would be if the customer decides to remain a requirements customer for the period for which the Commission finds that the supplying utility reasonably expected to continue serving the customer In such a case, the supplying utility will be obligated to offer continuing service to the requirements customer for the period the utility reasonably expected to continue serving the customer.

A requirements customer will be responsible for planning to meet its power needs beyond the end of the contract term by either building its own generation, signing a new power sales contract with its existing supplier, or contracting with new suppliers in conjunction with obtaining transmission service under its existing supplier's open access transmission tariff or another utility's transmission system. In so holding, it is not our intent to undermine any obligations specifically contained in a contract. Thus, if a contract explicitly establishes an obligation to serve beyond the end of the contract term, such a contractually-imposed obligation to serve (as distinguished from a regulatory obligation to serve) would be enforceable as a term of the contract. If a wholesale customer that switches suppliers later seeks to reestablish service with its former supplier, it will be up to the parties to negotiate their respective obligations.

We also reaffirm our preliminary determination to no longer require prior notice of termination under §35.15 for any power sales contract executed on or after the effective date of the Final Rule pro forma tariff (but to require written notification of the termination of such contract within 30 days after termination takes places). This determination goes hand-in-hand with our determination (discussed above) not to impose a regulatory obligation on wholesale requirements suppliers to continue to serve their existing requirements customers beyond the end of the contract term.[FN652] We clarify, however, that this decision applies only to a power sales contract that is to terminate by its own terms (such as on the contract's expiration date). We have revised §35.15 accordingly. We will, however, continue to require prior notice of cancellation or termination for any power sales contract that is proposed to be cancelled or terminated for a reason other than by the contract's own terms (such as a self-help provision related to, for example, a billing dispute), regardless of when the contract was executed. We also will continue to require prior notice of the proposed termination of any power sales contract executed before the effective date of the Final Rule pro forma tariff (even if the contract is to terminate by its own terms) as well as any unexecuted power sales contract that was filed before that date.

Further, we will retain the §35.15 filing requirement for all transmission contracts. The reason for retaining the §35.15 requirement for transmission contracts is that transmission will continue to be provided under conditions of potential market power, and the Commission must be assured that transmission owners are not exerting market power in termination of transmission contracts. In addition, this filing requirement will provide the customer an opportunity to notify the Commission if the termination terms are disputed or if the customer was not given adequate opportunity to exercise its limited right of first refusal under the Final Rule (see Section IV.A.5).

5. Recovery of Stranded Costs Associated With Existing Wholesale Requirements Contracts

In the Supplemental Stranded Cost NOPR, the Commission reaffirmed its proposal to permit the recovery of legitimate, prudent and verifiable stranded costs for a discrete set of "existing" wholesale requirements contracts (executed on or before July 11, 1994)—those that do not already contain exit fees or other explicit stranded cost provisions. We encouraged the parties to such contracts to renegotiate them to address stranded costs. In the case of existing contracts that already contain an exit fee or explicit stranded cost provision, however, we proposed to reject a unilateral stranded cost amendment; that is, we stated we would reject an amendment unless the contract permits renegotiation of the existing stranded cost provision or the parties to the contract mutually agree to renegotiate the contract.[FN653] In so doing, we proposed to drop the three year mandatory negotiation period suggested in the initial Stranded Cost NOPR.[FN654]

If an existing requirements contract does not contain an exit fee or other explicit stranded cost provision (and is not renegotiated to add such a provision), we proposed that before the expiration of the contract: (1) A public utility or its customer may file a proposed stranded cost amendment to the contract under section 205 or 206; or (2) a public utility or transmitting utility may file a proposal to recover stranded costs associated with any such existing contract through its transmission rates for a customer that uses the utility's transmission system to reach another generation supplier.

***21640** In the Supplemental Stranded Cost NOPR, we reaffirmed our proposal in the initial Stranded Cost NOPR that, even if the contract contains an explicit Mobile-Sierra[FN655] provision, it is in the public interest to permit public utilities to seek unilateral amendments to add stranded cost provisions if the contracts do not in essence forbid such recovery by containing exit fees or other explicit stranded cost provisions.[FN656] Under these circumstances, if neither of the parties seeks and obtains acceptance or approval of a stranded cost amendment, we propose to permit the public utility to seek recovery of stranded costs through its wholesale transmission rates.

We also proposed procedures for providing an existing wholesale requirements customer advance notice of how the utility would propose to calculate costs that the utility claims would be stranded by the customer's departure.[FN657]

Comments

a. July 11, 1994 Cut-Off Date

A number of commenters ask the Commission to reconsider the July 11, 1994 cut-off date for distinguishing between "existing" and "new" requirements contracts. Some commenters[FN658] support October 24, 1992 (the date of passage of the Energy Policy Act) as the cut-off date on the basis that anyone entering into a wholesale requirements contract after that date should have recognized the greatly increased possibility of the customer terminating or not renewing the contract.

Other commenters[FN659] support a later date for defining "new" requirements contracts, such as the date on which the final rule open access tariffs become effective. Utilities For Improved Transition argues that the Commission cannot retroactively adopt the July 11, 1994 cut-off date, but must wait until the final rule is issued before setting the date after which requirements contracts must contain stranded cost provisions in order for stranded cost recovery to be allowed.

Commenters representing electric cooperatives also oppose the July 11, 1994 cut-off date.[FN660] They contend that RUS borrowers were not free to negotiate stranded cost amendments to wholesale power contracts as soon as the Commission warned them to do so because their wholesale power contracts are mandated both as to form and substance by the RUS.[FN661]

PA Munis asks the Commission to treat certain contracts that were executed before July 11, 1994 (but not approved by the Commission until after that date) as "new" contracts. PA Munis argues that the utility, after issuance of the initial NOPR, could have withdrawn its filing of the contract and sought to negotiate an exit fee at that time. It submits that the utility's failure to do so would justify a finding by the Commission that contracts approved after July 11, 1994 be treated similarly to contracts executed after that date.

b. Stranded Cost Recovery for Existing Requirements Contracts

A number of commenters express support for the Commission's proposal to permit modification of existing requirements contracts that do not already contain exit fees or other explicit stranded cost provisions.[FN662] NEPCO states its interpretation that the NOPR does not consider notice provisions to be "explicit stranded cost provisions;" it argues that the presence of a notice provision in a contract, while bearing on the supplier's ability to demonstrate the duration of its reasonable expectation of continued service, should not foreclose the amendment of a wholesale contract to add an exit fee or similar payment provision. Several other commenters ask the Commission to clarify that contracts that contain notice provisions and that preclude recovery for termination or reduction of service (but that do not necessarily use the terms "exit fee" or "stranded cost"), or that expressly provide that stranded costs shall not be charged, cannot be reopened for a stranded cost claim.[FN663]

A number of other commenters oppose the Commission's proposal to permit amendment of wholesale requirements contracts that do not address stranded cost recovery, for reasons previously raised in this proceeding.[FN664] They argue, among other things, that contracts should stand on their own. RUS asserts that the integrity of its Federal loan program is to a large extent predicated on honoring the long-term requirements wholesale power contracts between G&Ts and their distribution members.

Several commenters also challenge the Commission's proposed determination that it is in the public interest to permit utilities to seek unilateral amendments to add stranded cost provisions to requirements contracts. These commenters argue that the NOPR's assumptions concerning the financial stability of public utilities are unsupported and thus do not meet the burden of proof required for the public interest finding under the Mobile-Sierra doctrine. They urge the Commission to require a utility-specific finding of imminent financial jeopardy before overriding a Mobile-Sierra contract.[FN665]

ELCON argues that the recent Northeast Utilities Service Company v. FERC [FN666] case reaffirms the traditional high threshold for overriding Mobile-Sierra clauses in the "classic Mobile-Sierra situation" in which one of the parties seeks modification of a contract that has already been reviewed and approved by the Commission. It submits that a utility seeking to add a stranded cost provision to an existing contract would fall within the "classic situation." ELCON also argues that the First Circuit strongly implied that to satisfy Mobile-Sierra, the Commission must identify specifically those aspects of a contract that are contrary to the public interest and why. On this basis, ELCON argues that the case supports its position that a utility-specific finding of imminent financial jeopardy is necessary to override an existing Mobile-Sierra contract.[FN667]

***21641** Some commenters argue that if utilities are to be granted industry-wide Mobile-Sierra relief, then the Commission should give wholesale customers the reciprocal right to convert their wholesale power contracts to transmission-only service.[FN668] However, EEI contends that the Commission is barred by section 211(c)(2) of the FPA from ordering wheeling where a customer is taking service under a contract or under a rate tariff on file with the Commission.

Several commenters ask the Commission to require renegotiation of the notice and/or term of all existing contracts with long lead-time cancellation provisions in order to allow all wholesale customers access to the market at the same time.[FN669] They submit that customers with short notice provisions will be the first to enjoy the benefits of open access and will have an effective "first right of refusal" of the most economical transmission paths and low cost suppliers, putting customers with long lead-time cancellations at a competitive disadvantage.

c. Transition Period

A number of commenters support the Commission's proposal not to mandate a three-year time limit for renegotiation of existing wholesale requirements contracts. They note that existing contracts have unique characteristics and complexities that affect the time required to renegotiate the contract bilaterally, to file a unilateral amendment with the Commission, or to file for stranded cost recovery through transmission rates.[FN670]

On the other hand, some commenters object that the proposal to replace the previously proposed three-year window with an opportunity to raise stranded cost claims throughout the existing contract term creates a virtually unlimited transition period.[FN671] For example, ELCON asserts that because the NOPR would allow utilities to seek amendment of an existing contract any time prior to its expiration, stranded cost issues could extend through the life of existing facilities (30 years or more). Portland suggests that the Commission set a schedule now for proceedings to determine transmission costs and stranded costs for each utility with wholesale requirements customers.

Commenters propose various limits to the period within which stranded cost recovery could be raised, such as: (i) Three to five years;[FN672] (ii) the lesser of three years from the effective date of the final rule or the remaining term of the contract;[FN673] (iii) one year from the effective date of the final rule;[FN674] and (iv) December 31, 1998 (20 years after PURPA).[FN675]

Commission Conclusion

a. July 11, 1994 Contract Cut-Off Date

We reaffirm our proposal to permit the recovery of legitimate, prudent and verifiable stranded costs for "existing" wholesale requirements contracts (executed on or before July 11, 1994) that do not already contain exit fees or other explicit stranded cost provisions. We believe that July 11, 1994—the date on which the initial Stranded Cost NOPR was published and, thus, on which the industry was put on notice of the proposal to disallow prospectively extra-contractual recovery of stranded costs—is the appropriate date for distinguishing "existing" requirements contracts from "new" requirements contracts. Because all parties were put on notice in the initial Stranded Cost NOPR that July 11, 1994 would be the operable date for the "existing"/"new" contract distinction, utilities that executed requirements contracts after that date could have had no reasonable expectation that they would be permitted to recover any costs extra-contractually.

Moreover, because the costs at issue are extra-contractual costs, the Commission's notice to all parties that contracts executed after July 11, 1994 will be enforced by their terms as far as stranded cost recovery is concerned does not constitute "retroactive rulemaking." Contrary to UFIT's contention, the Commission is not "requir[ing]" utilities to include stranded cost recovery provisions in all contracts executed after July 11, 1994.[FN676] The Commission has merely put all parties on notice that the opportunity for extra-contractual stranded cost recovery (which will be allowed on a prospective basis upon the effective date of the Rule) will not be available for any requirements contracts executed after July 11, 1994. The parties to requirements contracts executed after July 11, 1994 have been free to provide for stranded cost recovery in the contract, or not.[FN677] The point is that, for requirements contracts executed after the cut-off date, stranded cost recovery will be governed solely by the terms of the contract.

b. Stranded Cost Recovery for Existing Requirements Contracts

We reaffirm that we will permit utilities to seek recovery of stranded costs for a limited set of existing wholesale requirements contracts, namely, those that do not already contain exit fees or other explicit stranded cost provisions.[FN678] If an existing requirements contract includes an explicit provision for payment of stranded costs or an exit fee, we will assume that the parties intended the contract to cover the contingency of the buyer leaving the system. We will reject a stranded cost amendment to such a contract, unless the contract permits renegotiation of the existing stranded cost provision or the parties to the contract mutually agree to a new stranded cost provision. Similarly, we will reject a stranded cost amendment to an existing requirements contract if the contract prohibits stranded cost recovery (or precludes recovery for termination or reduction of service) or ***21642** prohibits renegotiation of an existing stranded cost or exit fee provision, unless the parties to the contract mutually agree to a new stranded cost provision.[FN679]

We reaffirm our desire that utilities attempt to renegotiate with their customers existing requirements contracts that do not contain exit fees or other explicit stranded cost provisions. If the parties negotiate a stranded cost provision and the seller is A public utility, the utility must file the provision with the Commission as an amendment to the existing requirements contract.

If an existing requirements contract does not contain an exit fee or other explicit stranded cost provision (and is not renegotiated to add such a provision), before the expiration of the contract: (1) a public utility or its customer may file a proposed stranded cost amendment to the contract under section 205 or 206; or (2) a public utility in a section 205 proceeding, or a transmitting utility in a section 211 proceeding, may file a proposal to recover stranded costs associated with any such existing contract through its transmission rates for a customer that uses the utility's transmission system to reach another generation supplier.

We thus reaffirm that if an existing requirements contract is not renegotiated, and the contract permits the seller and/or buyer to seek an amendment to the contract, the authorized party may seek an amendment to add a stranded cost provision. We also adopt our preliminary finding that, even if an existing requirements contract contains an explicit Mobile-Sierra provision, it is in the public interest to permit the public utility to seek a unilateral amendment to add stranded cost provisions if the contract does not already contain exit fees or other explicit stranded cost provisions. In the initial Stranded Cost NOPR, we identified two ways in which a failure to permit public utilities to address stranded costs could harm third parties, and thereby harm the public interest:

First, the inability to seek recovery of stranded costs could impair the financial ability of a utility to continue to provide reliable service. This will depend on the magnitude of stranded costs and the prospect or lack thereof for recovering such costs from ratepayers. The prospect of not recovering from ratepayers significant amounts of stranded costs could seriously erode a utility's access to capital markets, or could drive the utility's cost of capital to unprecedented levels. This high cost of capital could precipitate other customers leaving the system which, in turn, could cause others to leave. Such a spiral could be difficult to stop once begun. Second, if some customers are permitted to leave their suppliers without paying for stranded costs, this may cause an excessive burden on the remaining customers who, for whatever reason, cannot leave and therefore may have to bear those costs.[FN680]

The financial community commenters confirm our views in this regard. As they note, a utility's access to financial markets is essential to the continued provision of safe and reliable electric service to customers. However, the prospect of a utility not recovering stranded costs could erode a utility's ability to attract capital and thus imperil its continued financial stability.[FN681] As these and other commenters agree, the recovery of stranded costs is critical to the successful transition to more competitive markets.

Moreover, our determination that it is in the public interest to give public utilities a limited opportunity to propose contract changes unilaterally to address stranded costs if their contracts do not already explicitly do so satisfies the public interest standard of the Mobile-Sierra doctrine as recently interpreted by the Northeast Utilities court. In that case, the court affirmed an order of the Commission on remand modifying a contract under the Mobile-Sierra public interest standard.[FN682] As the court explained, the Mobile-Sierra doctrine "represents the Supreme Court's attempt to strike a balance between private contractual rights and the regulatory power to modify contracts when necessary to protect the public interest."[FN683] The court noted that when the Commission is considering whether a contract rate is too low, protective action by the Commission in the public interest is justified "where the rate might impair the financial ability of the utility to continue to supply electricity, force electricity consumers to bear an excessive burden, or be unduly discriminatory."[FN684]

The court also explained that "the most attractive case for affording additional protection [under the public interest standard], despite the presence of a contract, is where the protection is intended to safeguard the interests of third parties * * *."[FN685] It stated that the Mobile-Sierra doctrine allows the Commission to modify the terms of a private contract "when third parties are threatened by possible 'undu[e] discrimination' or the imposition of an 'excessive burden.'"[FN686] The court found that the Commission had met the public interest standard by showing how the contract could harm third parties.[FN687]

Consistent with the holding in Northeast Utilities, and contrary to the positions of some commenters, we have demonstrated how "third parties may ultimately bear the burden"[FN688] if public utilities with Mobile-Sierra contracts are not given any opportunity to propose contract changes to address stranded costs. If the Commission fails to give a public utility ***21643** this opportunity, and the utility's financial ability to continue the provision of safe and reliable service is impaired, third parties (customers relying on the public utility for their electric service) will be placed at risk. Similarly, if the Commission fails to give a public utility the opportunity to directly assign costs to the customers on whose behalf they were incurred, and some of the utility's customers leave the utility's generation system for that of another supplier without paying such costs, third parties (the utility's remaining customers) will be harmed by having to bear the costs that were not incurred to serve them and that are stranded by the other customers' departures via open access transmission. Moreover, we believe that protective action in the public interest is particularly necessary where, as here, a utility's rates could become insufficient because of fundamental changes in the industry that largely result from legislative or regulatory changes that could not be anticipated.

Further, notwithstanding the arguments of some commenters supporting a case-by-case (as opposed to a generic) public interest finding, we believe it appropriate that our public interest finding be made on a generic basis given the fact that, by this Rule, we are requiring full open access that could significantly affect historical relationships among traditional utilities and their customers and the ability of utilities to recover prudently incurred costs. We also emphasize that we are not eliminating the need for case-by-case demonstrations that stranded cost recovery should be allowed. Our public interest finding is that utilities be permitted to seek extra-contractual recovery of stranded costs in certain defined circumstances. Utilities seeking recovery of stranded costs will have the burden, on a case-by-case basis, of showing they had a reasonable expectation of continuing to serve the departing generation customer.

In summary, we emphasize the limited nature of our Mobile-Sierra public interest finding. First, our holding applies only to wholesale requirements contracts executed on or before July 11, 1994 that do not contain an exit fee or other explicit stranded cost provision. Thus, we will not permit modification of any contract that addresses the stranded cost issue explicitly, unless the contract specifically permits such modifications. Instead, we are simply examining requirements contracts that do not clearly address the issue in the context of the traditional regulatory regime under which they were signed—a regulatory environment in which it was assumed as a matter of course that the great majority of requirements customers would stay with their original suppliers and that these suppliers had a concomitant obligation to plan to supply these customers' continuing needs.

Second, although we have decided on a generic basis that it is in the public interest to permit public utilities with Mobile-Sierra contracts to make unilateral filings, we are not automatically approving any amendment that a particular utility might file. As we stated in the initial Stranded Cost NOPR, if a public utility unilaterally files a proposed stranded cost amendment under either section 205 or 206 of the FPA, this does not necessarily mean that the Commission ultimately will find it appropriate to allow such amendment.[FN689] In addition, customers with Mobile-Sierra contracts that do not explicitly address stranded costs may also file complaints under section 206 of the FPA to propose to address stranded costs in existing requirements contracts. The Commission will analyze any proposed stranded cost amendment to a Mobile-Sierra contract, whether proposed by the utility or by its customer, based on the particular circumstances surrounding that contract. Thus, the case-by-case findings that some commenters seek will, in effect, be made when the Commission determines whether to approve a proposed stranded cost amendment to a particular contract.

As discussed in Section IV.A (Scope), the Commission has concluded that although current conditions in the wholesale power market do not warrant the generic modification of requirements contracts, nonetheless the modification of certain requirements contracts on a case-by-case basis may be appropriate. We have concluded further that, even if customers under such contracts are bound by so-called Mobile-Sierra clauses, they nonetheless ought to have the opportunity to demonstrate that their contracts no longer are just and reasonable.

We have found that it would be against the public interest to permit a Mobile-Sierra clause in an existing wholesale requirements contract to preclude the parties to such a contract from the opportunity to realize the benefits of the competitive wholesale power markets. For purposes of this finding, the Commission defines existing requirements contracts as contracts executed on or before July 11, 1994.[FN690] By operation of this finding, a party to a requirements contract containing a Mobile-Sierra clause no longer will have the burden of establishing independently that it is in the public interest to permit the modification of such contract. The party, however, still will have the burden of establishing that such contract no longer is just and reasonable and therefore ought to be modified.

This finding complements the Commission's finding that, notwithstanding a Mobile-Sierra clause in an existing requirements contract, it is in the public interest to permit amendments to add stranded cost provisions to such contracts if the public utility proposing the amendment can meet the evidentiary requirements of this Rule. The Commission's complementary Mobile-Sierra findings are not mutually exclusive. Any contract modification approved under this section shall provide for the utility's recovery of any costs stranded consistent with the contract modification. The stranded costs must be prudently incurred, legitimate and verifiable. Further, the Commission has concluded that if a customer is permitted to argue for modification of existing contracts that are less favorable to it than other generation alternatives, then the utility should be able to seek modification of contracts that may be beneficial to the customer.

The Commission believes that the most productive way to analyze contract modification issues is to consider simultaneously both the selling public utility's claims, if any, that it had a reasonable expectation of continuing to serve the customer beyond the term of the contract and the customer's claim, if any, that the contract no longer is just and reasonable and therefore ought to be modified. Thus, if the selling public utility intends to claim stranded costs, it must present that claim in any section 206 proceeding brought by the customer to shorten or terminate the contract. Similarly, if the customer intends to claim that the notice or termination provision of its existing requirements contract is unjust and unreasonable, it must present that claim in any proceeding brought by the selling public utility to seek recovery of stranded costs. This will promote administrative efficiency and will permit the Commission to consider how the contracting parties' claims bear on one another.

***21644** The Commission does not take contract modification lightly. Whether a utility is seeking a contract amendment to permit stranded cost recovery based on expectations beyond the stated term of the contract, or a customer is seeking to shorten or eliminate the term of an existing contract, we believe that each have a heavy burden in demonstrating that the contract ought to be modified. Still, we believe that given the industry circumstances now facing us, both selling utilities and their customers ought to have an opportunity to make the case that their existing requirements contracts ought to be modified. By providing both buyers and sellers this opportunity, the Commission attempts to strike a reasonable balance of the interests of all market participants. The Commission expects that many of the arguments presented by buyers and sellers in such proceedings will be fact specific.

c. Transition Period

We reaffirm our proposal to allow a public utility or its customer to file a proposed stranded cost amendment, or to allow a public utility or transmitting utility to file a proposal to recover stranded costs through a departing generation customer's transmission rates, at any time prior to the expiration of the contract. There is no uniform time remaining on requirements contracts executed on or before July 11, 1994. Any limitation on the period in which parties could propose amendments covering stranded costs (e.g., 3 years) would thus unequally affect market participants. Those with long terms remaining on their contracts could object that immediately addressing the issue would not be cost effective. For example, a utility with a long remaining term (e.g., 20 years) might not even seek stranded cost recovery depending on the competitive value of its assets near the end of the contract term.[FN691] However, such a utility would invariably seek to preserve its option to seek stranded cost recovery if its failure to do so within a short period resulted in a waiver of its right to do so.

6. Recovery of Stranded Costs Caused by Retail-Turned-Wholesale Customers

In the Supplemental Stranded Cost NOPR, we stated that both this Commission and state commissions have the legal authority to address stranded costs that result from retail customers becoming wholesale customers who then obtain transmission under the open access tariffs.[FN692] We proposed that this Commission should be the primary forum for addressing the recovery of stranded costs caused by retail-turned-wholesale customers. We explained that if a retail customer becomes a legitimate wholesale customer (such as through municipalization), it becomes eligible to use the non-discriminatory open access tariffs:

If costs are stranded as a result of this wholesale transmission access, we believe that these costs should be viewed as 'wholesale stranded costs.' But for the ability of the new wholesale entity to reach another generation supplier through the FERC-filed open access transmission tariff, such costs would not be stranded.[FN693]

We accordingly proposed to define "wholesale stranded costs" to include stranded costs resulting from unbundled transmission for newly-created wholesale customers and sought comments on this definition.

We proposed to require the same evidentiary demonstration for recovery as that required if recovery were sought from a wholesale requirements customer. We reaffirmed our proposal in the initial Stranded Cost NOPR that a utility will have to show that the stranded costs are not more than the net revenues that the retail-turned-wholesale customer would have contributed to the utility had it remained a retail customer of the utility, and that the utility has taken and will take reasonable steps to mitigate stranded costs. We further proposed to deduct any recovery that a state has permitted from departing retail-turned-wholesale customers from the legitimate stranded costs of which we will allow recovery. In addition, we proposed to apply the same procedures for obtaining an estimate of maximum stranded cost exposure without mitigation to retail customers contemplating becoming wholesale transmission customers as those proposed for wholesale customers.[FN694]

Comments

Some commenters contend that stranded costs that result when a retail customer becomes a wholesale customer should be left to the states as a matter of law and comity.[FN695] These commenters argue, among other things, that because the facilities used to provide retail service to these retail customers were subject to state jurisdiction and were included in retail rate base when the service was rendered, the state is the appropriate entity to determine the extent to which those customers should compensate the utility for the stranding of these costs. According to ELCON, "(a) retail customer's new found access to the wholesale market does not provide FERC with authority over costs that originated with the local distribution function."[FN696]

Commenters assert that stranded costs resulting from the creation of new wholesale entities will occur as a result of state or local decisionmaking.[FN697] A number of commenters contend that in states where the state commission has control over municipalization, the Commission has no authority to provide for the recovery of stranded costs due to municipalization.[FN698] IL Com asserts that the Commission lacks authority over retail-turned-wholesale stranded costs, even in the absence of any explicit statutory authority for state commissions to address such costs. FL Com argues that the Commission should address the recovery of these stranded costs only upon petition from a state public utility commission.

According to some commenters, the availability of open access transmission tariffs does not convert the character of the costs of stranded generation that was built to serve retail customers from retail to wholesale.[FN699] CA Com argues that this reasoning could require the Commission to act as the primary forum for stranded costs resulting from retail wheeling if the Commission's jurisdiction over retail transmission is upheld. It argues that in such a case, there also would be a relationship between the Commission-jurisdictional transmission and stranded costs.

Some commenters also submit that the potential for retail customers to become wholesale customers has existed since the beginning of the industry and that utilities have had ample opportunity to adjust to this risk.[FN700] A number of commenters submit ***21645** that state commissions are in a better position than the Commission to address the recovery of costs that were incurred to serve retail customers and to take into consideration local concerns.[FN701]

NARUC recognizes that a "practical regulatory gap may exist that prevents [state commission] consideration of recovery of * * * potentially stranded costs" in certain instances "such as municipalization and cooperatives, where retail customers become wholesale customers under a FERC-approved open access tariff, [and] costs of the utility which served the customer at retail may become stranded." [FN702] NARUC proposes that the affected states and the Commission collaboratively develop mechanisms (which may involve amendments to the FPA, state statutes, or both) to eliminate these regulatory gaps.

Some commenters object that the Commission's proposal to be the primary forum for recovery of stranded costs caused by retail-turned-wholesale customers would make municipalization more expensive and therefore would discourage municipalities from seeking alternative sources of electricity.[FN703] Some argue that different treatment of stranded costs between federal and state authorities may lead to forum-shopping as a primary determinant in the decision to municipalize.[FN704]

A number of commenters also suggest that the NOPR is inconsistent with prior Commission treatment of municipalization because the Commission has historically promoted franchise competition between municipalities and utilities and has never before suggested that utilities could "penalize" municipalization decisions through generation cost add-ons to transmission rates.[FN705] VT DPS states: "By the Commission's logic, there would never have been an Otter Tail case. If Otter Tail could have made a stranded cost claim against the municipal utility Elbow Lake planned to create, Otter Tail would never have needed to refuse to wheel."[FN706]

Suffolk County states that the Commission already considered stranded costs in the context of retail-turned-wholesale customers in United Illuminating Company,[FN707] where the Commission required United Illuminating to remove a provision in its proposed transmission tariff that would have allowed it to recover stranded costs associated with former retail loads served by new municipal systems. Suffolk County states that the Commission made clear that stranded cost matters, including those caused by municipalization, properly would be raised before state regulatory authorities. It objects that the Open Access NOPR ignores this case. Suffolk County also submits that the Commission's adoption of the settlement approved by the Massachusetts DPU in the Massachusetts Bay Transportation Authority case should serve as an example of proper jurisdictional deference with respect to local issues.[FN708]

However, many other commenters support the Commission's proposal to be the primary forum for retail-turned-wholesale stranded costs.[FN709] These commenters submit, among other things, that the Commission's jurisdiction over such costs is clear.[FN710] Coalition for Economic Competition states that when a utility's costs are stranded through the availability of Commission-jurisdictional transmission service, the Commission must address those costs. It argues that commenters opposing the Commission's jurisdiction fail to analyze the Commission's duty to establish just and reasonable rates for Commission-jurisdictional transmission service.

A number of commenters support the Commission's proposal to address retail-turned-wholesale stranded costs on the basis that many state commissions either lack authority to address costs that are stranded because of expanding or newly-created municipal systems, or have failed to address such costs.[FN711] El Paso adds that any protection offered by state judicial condemnation proceedings does not obviate the need for the Commission's involvement in this issue, noting that condemnation awards may not provide full stranded investment recovery under the Commission's standards. In addition, El Paso suggests that municipalization may occur through means other than condemnation of the distribution systems of electric utilities, such as when a municipality constructs its own, duplicative distribution facilities.

Several commenters also indicate that by forthrightly addressing this issue, the Commission has removed a cloud of uncertainty that would have taken years to resolve through litigation.[FN712] El Paso states that the proposed rule is needed because utilities may be subject to stranded costs resulting from municipalization in two separate state jurisdictions.

In response to the argument that stranded costs are exclusively subject to state jurisdiction, SoCal Edison asserts that whether the costs are retail or wholesale is irrelevant because the issue is how and where these costs should be recovered. According to SoCal Edison, if the Commission finds that these costs are just and reasonable costs associated with providing open access transmission service, the Commission may allow utilities to recover them in Commission-regulated rates.

Coalition for Economic Competition notes that while utilities are aware of state laws allowing municipalities to condemn electric facilities and to form utilities, in recent decades, it has not happened on most systems. Moreover, it argues that merely being on notice that municipalization is a possibility does not relieve utilities of their state-imposed obligation to serve all ***21646** customers in their franchise areas. It asserts that utilities had to continue to invest in plant to satisfy their duty to serve. In addition, it submits that utilities had a reasonable expectation that they would continue to serve retail load because, among other things, state regulators set long amortization periods of 30-40 years for depreciation rates.

Some commenters state that the Commission also should ensure that stranded costs are recovered when a municipal utility annexes territory served by another utility or otherwise expands its service territory.[FN713] A number of commenters also urge the Commission to ensure recovery of costs that are stranded if a municipal utility or a newly-formed wholesale or municipal utility physically interconnects to another utility or builds new transmission or distribution facilities to the municipal system.[FN714]

Several commenters believe that close coordination between the Commission and state regulators as to the calculation of stranded costs is important in the case of municipalization.[FN715] A number of state commissions suggest that the Commission allow the states to set the level of retail-turned-wholesale stranded costs to be recovered in wholesale transmission rates set by the Commission.[FN716] They submit that this approach would respect state interests in controlling the rate impact of stranded costs, while allowing the Commission to design cost recovery, and would address the needs of industrial customers and other stakeholders by providing a forum before state regulators who will be more aware of their particular needs. Further, they contend that this approach would prevent relitigation of issues, minimize forum-shopping, and prevent legitimate and verifiable costs from falling through the cracks or being double-recovered.[FN717] NY Industrials asks the Commission to clarify that utilities will not be allowed to seek cost recovery at both the Commission and state commissions.

Commission Conclusion

We reaffirm our preliminary determination that this Commission should be the primary forum for addressing the recovery of stranded costs caused by retail-turned-wholesale customers. If such a customer is able to reach a new generation supplier because of the new open access (through the use of a FERC-filed open access transmission tariff or through transmission services ordered pursuant to section 211 of the FPA), we believe that any costs stranded as a result of this wholesale transmission access should be viewed as "wholesale stranded costs." Such costs would not be stranded but for the action of this Commission (either through a mandatory FPA section 205-206 open access tariff or an order under FPA section 211) in permitting the new wholesale entity to become an unbundled transmission services customer of the utility and thereby to obtain power from a new supplier.[FN718] There is a clear nexus between the FERC-jurisdictional transmission access requirement and the exposure to non-recovery of prudently incurred costs. In these circumstances, we believe that this Commission should be the primary forum for addressing recovery of such costs. To avoid forum-shopping and duplicative litigation of the issue, we expect parties to raise claims before this Commission in the first instance.[FN719]

Some commenters have asked us also to be the primary forum for stranded cost recovery in situations in which an existing municipal utility annexes territory served by another utility or otherwise expands its service territory. We decline to do so because in these situations there is no direct nexus between the FERC-jurisdictional transmission access requirement and the exposure to non-recovery of prudently incurred costs. The risk of an existing municipal utility expanding its territory was a risk prior to the Energy Policy Act and prior to any open access requirement.

Nevertheless, we are concerned that there may be circumstances in which customers and/or utilities could attempt, through indirect use of open access transmission, to circumvent the ability of any regulatory commission—either this Commission or state commissions—to address recovery of stranded costs.[FN720] We reserve the right to address such situations on a case-by-case basis.

As we indicated in the Supplemental Stranded Cost NOPR, if the state has permitted any recovery from departing retail-turned-wholesale customers (for example, if it imposed an exit fee prior to, or as a condition of, creating the wholesale entity), that amount will not, in fact, be stranded, and we will deduct that amount from the legitimate stranded costs for which we will allow recovery.

As discussed in Sections IV.J.8-IV.J.9, we will require the same evidentiary demonstration for recovery of stranded costs from a retail-turned-wholesale customer, and will apply the same procedures for determining stranded cost obligation, as that required in the case of a wholesale requirements customer.

***21647 7. Recovery of Stranded Costs Caused by Retail Wheeling**

In the Supplemental Stranded Cost NOPR, we stated that both this Commission and state commissions have the legal authority to address stranded costs that result from retail customers who obtain retail wheeling from public utilities in order to reach a different generation supplier.[FN721] Because the vast majority of commenters urged the Commission not to assume responsibility for retail stranded costs, except in certain circumstances, we preliminarily concluded that it is appropriate to leave it to state regulatory authorities to deal with any stranded costs occasioned by retail wheeling. We proposed to entertain requests to recover stranded costs caused by retail wheeling only when the state regulatory authority does not have authority under state law to address stranded costs at the time when the retail wheeling is required.[FN722] In so doing, we preliminarily accepted the view that stranded costs caused by retail wheeling are primarily a matter of local or state concern and thus, with the limited exception discussed above, generally must be recovered through retail charges.

We noted that the states have a number of mechanisms for addressing stranded costs caused by retail wheeling, one of which is a surcharge to state-jurisdictional rates for local distribution.[FN723] We encouraged the states to use the mechanisms available to them to address stranded costs.[FN724] We also noted that the states may use their jurisdiction over local distribution facilities to address "stranded benefits," such as environmental benefits associated with conservation, load management, and other demand side management programs.[FN725]

Comments

A number of commenters support the Commission's proposal for addressing stranded costs caused by retail wheeling.[FN726]

Other commenters urge the Commission to take a greater role in retail stranded cost recovery and to entertain requests to recover stranded costs as a backstop where: (1) State regulatory authorities have the authority to address stranded costs but either choose not to exercise that authority or fail to permit full stranded cost recovery;[FN727] or (2) the state commission's authority is unclear.[FN728]

Commenters that support a greater Commission backstop role argue, among other things, that because the Commission has exclusive ratemaking jurisdiction over any stranded cost charges imposed "for or in connection with" interstate transmission service by public utilities, the Commission has an obligation to regulate the recovery of stranded costs from interstate retail transmission customers.[FN729] A number of these commenters argue that the determining factor is who has the jurisdiction to review the rates for the service, not who has the jurisdiction to order the service.[FN730] They explain that the Commission has jurisdiction over generating facilities and associated costs to the extent appropriate to establish just and reasonable rates for jurisdictional services. They disagree with other commenters who argue that only the jurisdiction under whose authority the costs were incurred and initially recovered should have authority to order recovery of stranded costs.[FN731]

These commenters contend that the Commission cannot abdicate its regulatory responsibilities by either deferring to the state commissions or otherwise failing to independently address the issue.[FN732] EEI and the Coalition for Economic Competition refer to "a long line of cases (where) the courts have held that where a federal regulatory agency * * * is charged with implementing a statutory framework, that agency is without authority to deviate from or abdicate its statutory responsibilities."[FN733] According to Coalition for Economic Competition, for example, the Commission could satisfy its obligation to address stranded costs that arise from retail wheeling by allowing states to determine retail stranded cost charges in the first instance; to the extent that the state allows full recovery, Coalition for Economic Competition submits that the Commission's obligation would be satisfied.

EEI asserts that it would be unduly discriminatory and preferential for the Commission to refuse to address all stranded costs arising from retail wheeling. According to EEI, the same arguments that support the Commission's decision to address costs that are stranded where retail load municipalizes and where the state regulatory authority, at the time retail wheeling is required, lacks authority to act, apply with equal force to all other retail stranded costs. EEI submits that the nexus in these cases is that Commission-jurisdictional transmission service is the means by which the costs are stranded.[FN734]

Utility Working Group argues that the NOPR inappropriately characterizes the Commission's jurisdiction over retail stranded costs and that this could later be used against the Commission's exercise of its full authority. According to Utility Working Group, the NOPR depicts the Commission's jurisdiction as ***21648** being derived from state law (in other words, the Commission will act where state regulatory authorities have no authority over retail stranded costs and will not act where state regulatory authorities have such authority). If the Commission desires to afford substantial deference to the states regarding retail stranded costs, Utility Working Group contends that the final rule should reflect that policy determination; however, the rule should not confuse policy with jurisdiction by purporting to place limits on, or attempting to waive, the Commission's jurisdiction over such costs.

Entergy asserts that the Commission's jurisdiction over multi-state utilities provides further support for our jurisdiction over retail stranded costs in certain contexts. Entergy states that most of the eleven multi-state registered holding company systems have some form of Commission-jurisdictional agreement that allocates production and transmission costs among the systems' affiliated operating companies. It asserts that these agreements by their very nature allocate costs among jurisdictions (that is, between states). Many of these agreements equalize the cost of generating reserves among affiliated operating companies, and such reserve equalization formulas can shift retail stranded costs among states unless the Commission provides a regulatory forum to address cost-shifting. Citing Middle South Energy,[FN735] and City of New Orleans v. FERC,[FN736] Entergy submits that the Commission cannot sit on the sidelines when it comes to stranded retail costs on the Entergy system. According to Entergy, Commission and judicial precedent place on the Commission the responsibility to ensure that federally-approved costs and cost allocations are not undermined by state action.

Commenters also express concern that it will not be possible to be sure that a state regulatory authority has authority over retail stranded costs until after years of litigation. If the Commission waits for the resolution of challenges to state authority and a court holds that the state regulatory authority is without authority, these commenters assert that the bar on retroactive ratemaking could leave the states and the Commission without a remedy to compensate utilities for stranded costs.[FN737] A number of commenters suggest that while the states should be allowed to set retail wheeling stranded cost charges in the first instance, the Commission should accept filings to preserve a utility's ability to recover retail stranded costs from the time the customer departs if the state-authorized charges are not upheld in court. They submit that this would put customers on notice of the potential for Commission action and thereby avoid the retroactivity problem.[FN738]

Some commenters express concern that if the Commission does not take more decisive action on retail wheeling stranded costs, the result will be wasteful litigation that will discourage competition by causing financial uncertainty and higher financing costs for investor-owned utilities and higher rates for consumers.[FN739] Coalition for Economic Competition also asserts that stranded cost charges would be greatest at the start of a retail wheeling program, thereby making the years during which the state-authorized charges are subject to appeal more important for recovery purposes.

A number of commenters support Commission-established uniform standards for, and uniform recovery of, costs stranded as a result of open access to the interstate transmission system.[FN740] They argue that disparate state treatment of stranded costs would be economically inefficient and discriminatory and would burden interstate commerce.[FN741] Several commenters support state involvement in the establishment of uniform standards.[FN742]

In contrast to the commenters that support a greater Commission role in retail stranded cost recovery, NARUC and a number of other commenters oppose any Commission involvement in retail stranded costs.[FN743] These commenters contend, among other things, that the Commission lacks authority over these costs. Even if the Commission could assert such jurisdiction, they argue that as a policy matter it would be inappropriate for the Commission to delve into complicated legal and policy issues governed by varying state regulatory regimes.

According to some of these commenters,[FN744] section 201(a) of the FPA precludes an exercise of federal jurisdiction over retail stranded cost recovery because the Commission's jurisdiction extends "only to those matters which are not subject to regulation by the States."[FN745] NM Industrials argues that a lack of state commission authority is an affirmative state determination, either by act or omission, that stranded costs must be dealt with in a particular manner. It submits that the Commission also lacks authority over retail stranded costs when states either decide not to address such costs or, in the Commission's opinion, grant insufficient recovery of stranded costs. NM Industrials asserts that the language of the FPA and its legislative history indicate that Congress wanted to preclude Commission jurisdiction in those areas where states could exercise effective control, and that this limitation covers all matters which are or can be regulated by the states, including the recovery of stranded investment. NM Industrials also suggests that assertion of Commission jurisdiction would violate the provision of section 212 of the FPA that prohibits the Commission from interfering with the states' authority over the transmission of energy directly to an ultimate consumer.[FN746]

Other commenters argue that the Commission's proposed treatment of retail stranded costs infringes on the states' jurisdiction over the allocation of costs that were under their jurisdiction when the costs were incurred. According to these commenters, the question of whether these costs should be recovered from other retail ratepayers, eliminated as excess capacity, or billed in some fashion to the customer now receiving wheeling service are purely questions of state ratemaking law.[FN747] Some commenters assert that, as a matter of policy, the Commission should stay out of retail stranded costs because only the states have sufficient knowledge and expertise regarding utility planning, investment, ***21649** and forecasting to address these costs adequately.[FN748]

Commenters also express concern that the possibility of Commission involvement in retail stranded cost recovery will encourage forum-shopping whenever state commission action is unfavorable, even when states have procedures to deal with stranded costs. They argue that the result would be endless litigation over where federal jurisdiction ends and where state jurisdiction begins. They suggest that if a state fails to address retail stranded cost recovery, the issue should be addressed in court or in state legislatures.[FN749] OH Com contends that a Commission policy that does not recognize states' authority over retail stranded costs would be a disincentive for states to permit retail wheeling.

A number of commenters argue that recovery of retail stranded costs is not directly implicated by any Commission or Congressional action—that most such costs would be created by retail wheeling, which is not the subject of the Commission's open access initiatives—and thus need not be dealt with as part of the final rule.[FN750]

Commenters seek a number of clarifications concerning the Commission's position on, and the procedures for, retail stranded cost recovery. A number of commenters ask the Commission to clarify the states' role with respect to retail stranded cost recovery.[FN751] Others address the type of evidence required to establish that the state regulatory authority lacks authority to address stranded costs when retail wheeling is required.[FN752]

Several commenters express concern that customers receiving retail wheeling not be able to evade state stranded cost charges.[FN753] IL Com says that the Commission's proposal for determining whether facilities are state-jurisdictional "local distribution" facilities or Commission-jurisdictional "transmission" facilities in interstate commerce may not always provide a state with the opportunity to recover retail stranded costs through distribution rate surcharges. It says that the Commission does not offer any assurances that the case-by-case application of the proposed "functional-technical test" will result in a finding that "local distribution" facilities are used in all retail wheeling scenarios. PG&E asks the Commission to provide that all retail customers that opt for direct transmission access by definition take service over local distribution facilities and therefore may be subjected to a state-determined distribution rate that includes stranded cost surcharges.

A number of commenters ask the Commission to clarify that, in issuing the final rule, the Commission is not endorsing (either implicitly or explicitly) retail wheeling.[FN754]

Several commenters express concern that stranded costs may arise in one state jurisdiction and be shifted to another.[FN755] For example, MT Com says that an analysis confined to a state's boundaries may reveal no stranded costs, but that such costs may indirectly arise because of common pool revenue recovery mechanisms, which may be the largest source of stranded costs for some utilities. Entergy raises a similar concern in the context of holding company or other multi-state situations. It argues that denial of retail stranded cost recovery by a state regulatory authority could harm customers in other states. Entergy proposes that, while state regulators should be given the opportunity in the first instance to assure that stranded costs are recovered and are not shifted to other states, the Commission should allow utilities to file retail wheeling tariffs with the Commission to preserve the right to seek recovery from the Commission.

Several commenters oppose Entergy's proposal.[FN756] Among other things, they argue that the FPA does not authorize the Commission to act as an appellate court over retail regulators. They assert that, in the case of a multi-state holding company system, it is the Commission-jurisdictional intra-system agreement (not a state's decision as to recovery of retail stranded costs) that determines the allocation of costs at wholesale among the affiliates. Several of these commenters suggest that if the holding company believes that, as a result of a state's disallowance of costs in retail rate base, the cost allocations under an intra-system agreement are unduly discriminatory, the holding company could propose to amend the agreement.[FN757]

A number of commenters also express concern that services that investor-owned utilities provide to promote energy efficiency and conservation and to assist low-income residents and the elderly be continued.[FN758] NW Conservation Act Coalition suggests that the Commission should condition stranded cost recovery upon a showing by the utility that allowing recovery will not strand such social benefits.[FN759]

Various commenters endorse the use by state regulators of a distribution charge or other fee imposed on electricity consumption to address stranded social benefits.[FN760] NARUC and OH Com express concern that the Commission, by claiming authority over unbundled retail transmission services, may make it difficult for states to use non-bypassable "wires charges" or "access fees" to require all customer classes to support such programs.[FN761] NARUC asks the Commission to ensure that any jurisdiction we exercise over unbundled transmission services does not legally or practically foreclose the ability of individual states to fund such programs.[FN762] LILCO, as part of its argument that the Commission should provide a complete backstop for stranded cost recovery resulting from retail wheeling, urges the Commission to establish retail wheeling rates that provide for full recovery of any stranded costs, including stranded social benefits, ***21650** that are unrecovered after state stranded cost determinations.

Commission Conclusion

We believe that both this Commission and the states have the legal authority to address stranded costs that result when retail customers obtain retail wheeling in order to reach a different generation supplier, and that utilities are entitled, from both a legal and a policy perspective, to an opportunity to recover all of their prudently incurred costs. This Commission's authority to address retail stranded costs is based on our jurisdiction over the rates, terms, and conditions of unbundled retail transmission in interstate commerce. The authority of state commissions to address retail stranded costs is based on their jurisdiction over local distribution facilities and the service of delivering electric energy to end users. However, because it is a state decision to permit or require the retail wheeling that causes retail stranded costs to occur, we will leave it to state regulatory authorities to deal with any stranded costs occasioned by retail wheeling. The only circumstance in which we will entertain requests to recover stranded costs caused by retail wheeling is when the state regulatory authority[FN763] does not have authority under state law to address stranded costs when the retail wheeling is required.

Commenters that describe our action as an unlawful abdication or delegation of authority misconstrue the nature of our decision to leave retail stranded costs (with a limited exception) to state regulatory authorities.[FN764] We have not "abdicated" or "delegated" to state regulatory authorities our jurisdiction over the rates, terms, and conditions of retail transmission in interstate commerce; if retail transmission in interstate commerce by a public utility occurs, public utilities offering such transmission must comply with the FPA by filing proposed rate schedules under section 205. Instead, we have made a policy determination that the recovery of retail stranded costs—an issue over which either this Commission or state commissions could exercise authority by virtue of their jurisdiction over retail transmission in interstate commerce and over local distribution facilities and services, respectively—is primarily a matter of local or state concern that should be left with the state commissions. However, if the state regulatory authority does not have authority under state law to address stranded costs when the retail wheeling is required, then we will entertain requests to recover such costs.[FN765]

Because we have accepted the view that stranded costs caused by retail wheeling are primarily a matter of local or state concern, we will not allow the states to use the interstate transmission grid as a vehicle for passing through any retail stranded costs, with the following limited exception. If the state regulatory authority does not have authority under state law when the retail wheeling is required to resolve the retail stranded cost issue, we will permit a utility to seek a customer-specific surcharge to be added to an unbundled transmission rate.

We believe that most states have a number of mechanisms for addressing stranded costs caused by retail wheeling.[FN766] In addition, as further discussed in Section IV.I, we are defining in this rule "facilities used in local distribution" under section 201(b)(1) of the FPA. Rates for services using such facilities to make a retail sale are state-jurisdictional, and states will be free to impose stranded costs caused by retail wheeling on facilities or services used in local distribution. States may also use their jurisdiction over local distribution facilities or services to recover so-called stranded benefits. This rule is not intended to preempt any existing state authority to assess a stranded cost or stranded benefits charge on a retail customer that obtains retail wheeling. Moreover, since the charge is state jurisdictional, it is of no moment to our responsibilities under the FPA as to whether such charges are volume-based (kWh), demand-based (kW), or customer-based (fixed).

We believe that our approach to retail wheeling stranded costs represents an appropriate balance between federal and state interests. This approach ensures that the rates for transmission in interstate commerce by public utilities (except in a narrow circumstance) will not be burdened by retail costs. It also helps to ensure that one state will not be able to impose costs stranded by its ordering of retail wheeling[FN767] on customers in another state.[FN768] In a holding company or other multi-state situation, we recognize that denial of retail stranded cost recovery by a state regulatory authority could, through operation of the reserve equalization formula in a Commission-jurisdictional intra-system agreement, inappropriately shift the disallowed costs to affiliated operating companies in other states. The Commission is concerned about this potential for cost-shifting. We would not wish to see an intra-system agreement used as a means for one jurisdiction to shift to other jurisdictions retail stranded costs for which it would otherwise be responsible under that agreement. However, we will deal with such situations if they arise pursuant to public utility filings under section 205 or complaints under section 206. Thus, the need to amend a jurisdictional agreement to prevent retail stranded costs from being shifted to customers in other states will be addressed on a case-by-case basis. We encourage the affected state commissions in such situations to seek a mutually agreeable approach to this potential problem. If such a consensus solution resulted in a filing to modify a jurisdictional agreement, we would accord such a proposal deference, particularly if other interested parties support the filing. In the event that the state commissions and ***21651** other interested parties cannot reach consensus that would prevent cost shifting, the Commission would ultimately have to resolve the appropriate treatment of such stranded costs.

Should a situation arise in which a state regulatory authority concludes that it has no ability to address retail stranded costs, or the appropriate state courts ultimately determine that a state regulatory authority does not have authority to impose retail stranded costs, a utility may seek recovery here through its Commission-jurisdictional retail transmission rates of costs stranded as of the date of the customer's departure. Because all parties are put on notice by this Rule of the potential for recovery through Commission-jurisdictional retail transmission rates should state commission-authorized retail wheeling charges be invalidated, such recovery (if allowed) would not be retroactive ratemaking.[FN769]

8. Evidentiary Demonstration Necessary—Reasonable Expectation Standard

In the Supplemental Stranded Cost NOPR, the Commission made a preliminary determination that a public utility or transmitting utility seeking to recover stranded costs must demonstrate that it had a reasonable expectation of continuing to serve a customer. We indicated that the existence of a notice of termination provision in a wholesale requirements contract creates a rebuttable presumption that the utility had no reasonable expectation of serving the customer beyond the period provided for in the notice provision.[FN770] We proposed not to adopt a minimum notice period for purposes of applying the rebuttable presumption. This was because whether a utility has a reasonable expectation of continuing to serve a customer, and for how long, including whether there is sufficient evidence to rebut the presumption that no such expectation existed beyond the notice provision in the contract, will depend on the facts of each case.

We sought further comment concerning whether the reasonable expectation standard should apply if a utility has been making wholesale requirements sales to a customer in a non-contiguous service territory and where, in order to make such a sale possible, transmission service has been rendered by an intervening utility. We asked whether the Commission should take this as conclusive evidence that the customer had a choice of wholesale suppliers and, therefore, that the seller had no reasonable expectation that the contract would be extended. We further asked should we choose to provide the seller with an opportunity to prove that it had a reasonable expectation, what weight should be given to the fact that transmission service was rendered by the intervening utility. If the seller establishes that it had a reasonable expectation, and the former wholesale customer does not take unbundled transmission service from the former seller, we asked what if any means ought to be available for the collection of stranded costs.[FN771]

We also proposed to require the same evidentiary demonstration for recovery of stranded costs from a retail-turned-wholesale customer or a retail customer that obtains retail wheeling as that required when a wholesale requirements customer leaves a utility's system. We proposed that the utility must demonstrate that it incurred stranded costs based on a reasonable expectation that the customer would continue to receive bundled retail services. We anticipated that the reasonable expectation test would be easily met in those instances in which state law awards exclusive service territories and imposes a mandatory obligation to serve. We requested comments on these proposals.[FN772]

Comments

a. Rebuttable Presumption

Some commenters oppose treating a notice provision as a rebuttable presumption that the utility had no reasonable expectation of continuing to serve a customer. Commenters representing the financial community (Utility Shareholders and Utility Investors Analysts), for example, state that investment in generation and other costs incurred in providing utility service have not been tied to notice provisions. Based on the use of notice provisions in the past, and their infrequent use for termination, they state that the financial community has not viewed notice provisions as a determinant of the financial basis of investment in the industry.

Other commenters also argue that the Commission interprets the intent behind termination notice provisions too narrowly. These commenters submit that the Commission should examine on a case-by-case basis whether a notice provision demonstrates a sufficient meeting of the minds between the parties that there was no reasonable expectation that the contract would be extended.[FN773] TVA notes that the existence of a notice provision in its contracts in no way implies that continued service would not be expected.

A number of commenters[FN774] note that some utilities have "evergreen" contracts that remain in effect indefinitely unless either party gives notice that it intends to terminate the contract. They argue that, with no date certain for termination, the provider of bundled service must proceed on the assumption that it will have to meet its contract obligations on a continued basis. CSW recommends that the Commission limit the rebuttable presumption standard to contracts that contain a fixed contract termination date. IN Com suggests that where a contract contains an evergreen provision, the Commission should consider how often the contract has been automatically renewed and the length of the notice period.

A number of commenters suggest that the following factors should be conclusive proof of a reasonable expectation (or sufficient to conclusively rebut the presumption of no reasonable expectation): (1) An obligation under statute, certificate of public convenience and necessity, order or otherwise, granted to the utility to provide service to the area that includes the customer; (2) participation by the customer in regulatory proceedings that defer the utility's complete recovery of the costs associated with existing investment to a later period; or (3) service under a wholesale rate that averaged the cost of all of a utility's generation resources, both long-term and short-term.[FN775] Utilities For Improved Transition maintains that a customer whose rates were based on the totality of a utility's resources, including those with long life expectancies, ***21652** cannot claim that the governing expectation was that the utility would serve the customer only for a period of one to three years.

Other commenters, in contrast, assert that the rebuttable presumption does not go far enough. These commenters submit that a notice of termination provision should create a conclusive presumption that a utility had no reasonable expectation of continuing to serve a customer beyond the notice period.[FN776] Some commenters[FN777] also support a conclusive presumption of no reasonable expectation where one or more of the following grounds are present: (1) An explicit termination provision, regardless of the length of the pre-termination notice period; (2) an explicit provision for decreasing service or switching to partial requirements service; (3) a pre-existing transmission tariff or transmission service schedule; (4) NRC license conditions providing for transmission service or pooling rights;[FN778] (5) a municipal joint action agency or G&T cooperative with authority to supply the wholesale load in question; (6) a fixed-term contract; (7) membership in a power pool that provides access to regional markets; (8) a contract entered into after passage of the Energy Policy Act; or (9) other evidence of an ability to seek alternative suppliers. Several of these commenters, such as TAPS and Detroit Edison Customers, submit that a conclusive, irrebuttable presumption would decrease the number of disputes over stranded cost issues.

Several comments were submitted concerning the examples listed in the NOPR that the Commission suggested, depending on all of the facts and circumstances, could establish a reasonable expectation that a contract would be extended. These examples include lack of access to alternative suppliers, repeated contract renewals, failure of a customer to object to the imposition of construction-work-in-progress, or communications between supplier and customer concerning including the customer's load in system planning.[FN779] Some commenters argue that evidence of this type should not be enough to rebut the presumption (or to overcome a summary judgment motion based on the presumption) of no reasonable expectation for contracts with notice provisions.[FN780] ELCON objects to using a customer's lack of alternative supply as evidence of a continued service obligation; it submits that the historic lack of supply alternatives has been caused by undue exercise of market power and should not be rewarded.[FN781] Las Cruces suggests that if lack of opposition to construction-work-in-progress evidences a reasonable expectation of continued service, continuous opposition should evidence a reasonable expectation that the customer will depart a system at the earliest possible date. With regard to the Commission's suggestion that communications with the customer on the customer's future plans could establish reasonable expectation, Direct Service Industries submits that no claimed reliance should be deemed reasonable unless the seller obtained express assurances from the customer that the customer intended to continue to purchase power from the seller beyond its current contract.

We also received comments on the time at which the reasonable expectation had to exist. TAPS urges that the Commission should focus on whether a utility had a reasonable expectation of continued service when it entered into the most recent execution, renewal or amendment of the power supply contract.[FN782] PSE&G, on the other hand, argues that the focus of the Commission's review should be whether, at the time of incurring or obligating itself to incur the cost of serving a customer, the utility had a reasonable expectation of serving that customer for its planning horizon.

b. Application of Reasonable Expectation Standard to Non-Contiguous Service Territory

Some commenters discuss the situation in which a utility has been making wholesale requirements sales to a customer in a non-contiguous service territory and, in order to make such a sale possible, transmission service has been rendered by an intervening utility. They argue that this situation presents conclusive evidence that the customer had a choice of wholesale suppliers and, therefore, that the seller had no reasonable expectation that the contract would be extended.[FN783] Direct Service Industries submits that if a customer has power supply options that do not rely on access to the selling utility's transmission system, the selling utility could have had no reasonable expectations other than those expressly created by contract. NM Industrials submits that allowing recovery of stranded costs in this situation would also constitute retroactive ratemaking in violation of Arkansas Louisiana Gas Company v. Hall.[FN784] It argues that by assessing stranded costs at the close of a contract's term against customers that do not even need a generating utility's transmission services to leave its system, the Commission would retroactively alter the terms and conditions of the rates for generation negotiated between the parties and approved by the Commission.

Other commenters submit that in these circumstances the Commission should give the supplier the opportunity to prove that it had a reasonable expectation that it would continue to serve the customer.[FN785] ELCON and WP&L state that the reasonable expectation standard should be satisfied (or not) by reference to the parties' existing contract, regardless of whether the customer is in a contiguous service territory.

Utility Investors Analysts asserts that a seller will always have a reasonable expectation that a business relationship can be continued with a current customer and that the better presumption would be that the contract will be extended unless evidence to the contrary exists.

***21653 c. Application of Reasonable Expectation Standard to Retail-Turned-Wholesale Customers or To Retail Wheeling**

A number of commenters support the Commission's proposal to apply the reasonable expectation standard in these cases.[FN786] PA Com submits that the case-by-case analysis contemplated by the Commission for establishing a utility's reasonable expectation of continuing to serve a wholesale requirements customer should also apply in the case of a retail-turned-wholesale customer or a retail customer that obtains retail wheeling.

Some commenters believe that the reasonable expectation test would be easily met in those instances in which state law awards exclusive service territories and imposes an obligation to serve.[FN787] Some contend that the reasonable expectation standard should be presumed met in these circumstances because state law obligates a utility to serve all retail customers. A number of commenters assert that such a presumption would obviate the need for case-by-case showings concerning the expectations of each utility and the nature of each franchise.[FN788] At a minimum, several commenters propose that the Commission adopt a rebuttable presumption that utilities had an obligation to serve retail customers and therefore that the reasonable expectation test is met in a retail-turned-wholesale customer scenario or in the case of costs stranded as a result of retail wheeling.[FN789]

On the other hand, a number of commenters argue that there is no basis for a utility to reasonably expect that it will continue to serve a particular customer in states where franchises are non-exclusive.[FN790] Several of these commenters argue that a utility operating under a non-exclusive franchise is faced with the ever-present prospect that the communities it serves may build their own systems.[FN791]

Other commenters oppose the suggestion that the reasonable expectation test cannot be met where a franchise is non-exclusive or has terminated.[FN792] They argue that a utility's obligation to serve retail customers arises under state laws independent of the franchise. SoCal Edison explains that in states such as California, a franchise is nothing more than the source of a utility's right to use the city's streets, poles, rights of way, etc., and that a utility's duty to serve extends to all customers within its certificated service territories and not simply to those areas in which it has a franchise.

Commission Conclusion

We reaffirm that a utility seeking to recover stranded costs must demonstrate that it had a reasonable expectation of continuing to serve a customer. Whether a utility had a reasonable expectation of continuing to serve a customer, and for how long, will be determined on a case-by-case basis, and will depend on all of the facts and circumstances.[FN793]

Further, we will apply the reasonable expectation standard in those cases where a utility has been making wholesale requirements sales to a customer in a non-contiguous service territory and, in order to make such a sale possible, transmission service has been rendered by an intervening utility. We believe it is appropriate to give the utility an opportunity to prove that it had a reasonable expectation of contract renewal in circumstances in which the remote customer becomes an unbundled transmission services customer of the former supplier.[FN794]

We also reaffirm our determination that the existence of a notice provision in a contract creates a rebuttable presumption that the utility had no reasonable expectation of serving the customer beyond the specified period. Whether or not a contract contains an "evergreen" or other automatic renewal provision will be a factor to be considered in determining whether the presumption of no reasonable expectation is rebutted in a particular case.

We will not adopt a minimum notice period for purposes of applying the reasonable expectation rebuttable presumption. Whether a utility had a reasonable expectation of continuing to serve a customer, including whether there is sufficient evidence to rebut the presumption that no such expectation existed beyond the notice provisions in a contract, will depend on the facts of each case.

In addition, we reaffirm our preliminary determination to apply the reasonable expectation standard to retail-turned-wholesale customers. In this scenario, before the Commission will permit a utility to recover stranded costs, the utility must demonstrate that it incurred such costs based on a reasonable expectation that the retail-turned-wholesale customer would continue to receive bundled retail service. Whether the state law awards exclusive service territories and imposes a mandatory obligation to serve would be among the factors to be considered in determining whether the reasonable expectation test is met in a particular case.[FN795]

We further note that we are not addressing in this Rule who will bear the stranded costs caused by a departing generation customer if the Commission finds that the utility had no reasonable expectation of continuing to serve that ***21654** customer. As we suggested in the initial Stranded Cost NOPR,[FN796] we anticipate that, in such a case, a public utility will seek in subsequent requirements rate cases to have the costs reallocated among the remaining customers on its system. However, we will not prejudge that issue here.

9. Calculation of Recoverable Stranded Costs
In the Supplemental Stranded Cost NOPR, the Commission proposed that the determination of recoverable stranded costs be based on a "revenues lost" approach. Under this approach, stranded costs are calculated by subtracting the competitive market value of the power the customer would have purchased from the revenues that the customer would have paid had it stayed on the utility's generation system. We cited several benefits that we believe a "revenues lost" approach offers over a hypothetical cost-of-service approach, including avoidance of an asset-by-asset review, minimization of cost allocation procedures, and ease of application.[FN797]

We sought comments on how to calculate what the utility's revenue stream would have been had the customer continued service. We also sought comments on how to calculate the revenues that the utility would receive in a competitive market for the stranded assets. This included whether we should require the utility to track the actual selling price of the power over time or require the utility to use an up-front approach (such as an estimate of the forecasted market value of the power for the period during which the customer would have taken service). We asked whether we should allow prices in futures markets or forward markets to be used in an up-front approach, assuming such financial instruments become available.[FN798]

We suggested that the revenues lost approach automatically takes account of mitigation measures because it reduces the amount of stranded costs recoverable by a utility by the market price of the power that the customer no longer takes. We noted that this is particularly so if mitigation is reflected through a one-time, up-front estimate of the future market value of the power and is not trued up over time. We sought comments regarding implementation of a mitigation requirement. If mitigation is trued up over time, we asked how the Commission should ensure that the utility takes all reasonable steps to mitigate its own costs so as to minimize what the customer would have paid. We also asked how the Commission should ensure that the utility does its best to sell the power at its highest possible value. In addition, we asked whether there are other mitigation measures that should be taken into account (such as efficiency improvements that a utility would have undertaken regardless of whether the particular customer continued to take power under its contract, or cost savings resulting from the buy-out of a fuel contract made possible by the customer's departure).[FN799]

With regard to determining how long a utility could have reasonably expected to keep a generation customer (which we will call the "reasonable expectation period"), we preliminarily found that a one-size-fits-all approach is not appropriate. We sought further comment with respect to whether the Commission ought to establish presumptions or, in the alternative, absolute limits on a customer's maximum liability when a utility establishes that it had a reasonable expectation that the contract would be extended. We inquired whether it would be appropriate to pick an outer limit equal to the revenues that the utility would lose during the length of one additional contract extension period, or during the length of the utility's planning horizon. We also asked what other events or criteria might be used to establish either presumptions or absolute limits on the reasonable expectation period.[FN800]

In addition, we proposed procedures for providing a customer advance notice of how the utility would propose to calculate costs that the utility claims would be stranded by the customer's departure.[FN801] We invited comments on these procedures.[FN802]

Comments

a. Revenues Lost Approach
Numerous commenters, including almost all investor-owned utility commenters, support the revenues lost approach for calculating stranded costs.[FN803] Among other things, commenters maintain that the revenues lost approach is fair, reliable, and less complicated than the asset-by-asset approach. As discussed below, while some of these commenters support an "up-front" determination of stranded costs with no subsequent adjustments, others prefer use of a true-up mechanism whereby a customer's responsibility for stranded costs is adjusted to the extent that the actual competitive market value is different from the estimated market value used to determine the customer's up-front stranded cost charge.

Other commenters, on the other hand, oppose the revenues lost approach.[FN804] Some commenters state that the revenues lost approach provides no incentive to mitigate stranded costs because, by permitting a utility to recoup from a departing generation customer the difference between the contract price and a power resale price, the utility receives the same total revenues regardless of whether the customer stays or leaves and regardless of whether the utility effectively mitigates stranded costs.[FN805] Others maintain that the revenues lost approach is imprecise.[FN806] Referencing the problems associated with avoided cost projections used in setting QF rates under PURPA, some of these commenters submit that the revenues lost approach also requires significant assumptions (regarding projected revenue streams, service levels, and generic market value forecasts).[FN807] Among the other criticisms of the revenues lost approach that are raised by commenters are that it leads to over-recovery of stranded costs,[FN808] is ***21655** anticompetitive,[FN809] and that it leads to cost shifting.[FN810] NARUC and TDU Systems also maintain that it is likely that assets stranded by a customer's departure from the utility's generation system will be used to serve new customers but that the revenues lost approach offers no method of accounting for such "unstranding" of assets.

A number of commenters request clarification of the stranded cost formula contained in the NOPR, including specific instructions regarding how to calculate the revenues the customer would have paid the utility had it remained a customer and the competitive market value of the power the customer would have purchased.[FN811] Some of these commenters suggest that the stranded cost issue will be more contentious if the final rule does not provide greater detail.[FN812] Several commenters request that the Commission issue a detailed list of recoverable costs.[FN813] A number of commenters propose detailed alternatives to, or variations of, the revenues lost approach.[FN814]

Numerous commenters urge the Commission to be flexible and not overly prescriptive regarding the calculation of the formula components.[FN815] These commenters generally recommend that the Commission judge each stranded cost proposal on a case-by-case basis.[FN816]

Definition and Calculation of Revenue Stream

Some commenters maintain that the revenue stream component should be calculated based on the present rates paid by the customer.[FN817] These commenters state that because present rates have been approved by various commissions, the costs have been shown to be legitimate, prudent, and verifiable.

Other commenters oppose the use of current rates to calculate the utility's revenue stream. WP&L believes that the use of current rates would be overly generous and recommends capping the revenue measure at a regional average rate rather than a utility-specific rate. A number of other commenters argue that the effects of competition should be factored into the revenue stream by using the rates for capacity and energy actually offered or available in the utility's marketplace, such as incentive and special rates, not just the tariff rates to a particular customer.[FN818] Several commenters support removal of rate of return-related revenues associated with stranded assets, including risk premiums that are designed to compensate for potential nonrecovery of stranded costs.[FN819] EEI, in contrast, opposes any disallowance of rate of return-related revenues on the grounds that such a disallowance would violate the constitutional bar against the taking of private property without just compensation. Electronic Data Systems recommends calculation of the revenue stream using projected rates that include the effects of future rate increases.

The Commission requested comments on what categories of costs, in addition to investment costs, should be eligible for stranded cost recovery. In response, many commenters support the inclusion in the revenue stream calculation of additional costs, termed "special" costs, that may not be currently reflected in the rates paid by the departing customers, but that were incurred to provide service to these customers.[FN820] "Special" costs include: (1) Nuclear decommissioning costs; (2) environmental obligations existing at the time of the customer's departure; (3) purchased power contracts; (4) buyouts and buydowns of purchased power contracts; and (5) all regulatory assets, including deferred costs of generating assets for which regulators have promised recovery, deferred taxes, transition costs for post-employment benefits other than pensions, and contingent liability.

Other commenters oppose the inclusion of "special" costs in the calculation of the revenue stream.[FN821] TAPS questions how a customer can be held responsible for a cost that, by definition, it was never under a contractual obligation to pay. WP&L states that suppliers' rates should already reflect reasonable estimates of decommissioning costs and, therefore, no additional recovery is warranted.

Some commenters argue that the calculation of stranded costs should include social costs, such as demand side management, environmental costs, low income assistance costs, and costs associated with the management of fish and wildlife.[FN822]

NARUC states that the Commission should not preempt the ability of states to establish competitively neutral programs, such as DSM and energy efficiency, environmental mitigation, and R&D.

Various commenters state that any determination of stranded costs should take into account all offsetting benefits realized by the transmission provider upon a customer's departure.[FN823] Some commenters describe these costs as "stranded benefits."[FN824]

Most commenters favor the removal of avoided variable costs from the calculation of stranded costs on the basis that only fixed costs are truly stranded.

Some commenters support prioritizing stranded cost recovery.[FN825] These commenters argue that stranded costs should be categorized and ranked by the degree of responsibility that utilities had for their incurrence. Utilities would be allowed the greatest percentage of recovery for those stranded costs over which they had the least control.

Definition and Calculation of the Competitive Market Value

There generally was no consensus among the commenters concerning how ***21656** to determine the revenues a utility would receive in a competitive market for the stranded assets, that is, the competitive market value.[FN826] Proposals for calculating competitive market value include using: (1) The marginal cost of the released capacity; (2) the long-run marginal cost of the most competitive incremental generation replacement technology; (3) the marginal cost of requirements service; (4) a combination of the marginal costs of the utility, alternative suppliers, and others; (5) the cost of a combined cycle combustion turbine; (6) the price paid by the departing generation customer; (7) the highest price available in the market; and (8) auctions. In addition, to the extent that a futures market is sufficiently well-developed when the Commission issues a final rule, several commenters believe that futures market prices could be used as an estimate of market value.[FN827]

MT Com contrasts the effect of using short-term nonfirm prices instead of long-term firm prices as the competitive market value. It states that if short-term nonfirm prices are used, the stranded cost estimate would be higher, because the market price of short-term nonfirm power is lower than both the market price of long-term firm power and the embedded cost price.

Some commenters express concern regarding the difficulty of determining the market value of the displaced capacity under the revenues lost approach.[FN828] Among other things, commenters note that because a competitive market does not yet exist, the market price cannot be calculated in advance. For this reason, several commenters support an after-the-fact determination of market value.[FN829]

Snapshot Approach vs. True-Ups

Commenters are split on whether the revenues lost approach should use a one-time snapshot approach[FN830] or whether true-ups should be required or allowed.[FN831] The primary rationale offered in support of a snapshot approach is certainty;[FN832] the primary rationale offered in support of true-ups is accuracy.

Commenters that support true-ups note the inaccuracy associated with long-term avoided cost estimates contained in PURPA-mandated QF contracts and maintain that the projections required by the revenues lost approach will produce similarly disastrous results if true-ups are not permitted. As a component of the true-up calculation, some commenters favor inclusion of revenues associated with future load growth of remaining customers.[FN833] According to Electronic Data Systems, if these revenues are not included in a true-up calculation, the utility could over- or under-collect stranded costs, depending on whether and what type of load growth is anticipated. CA Energy Co and American National Power recommend consideration of load growth of remaining customers as a mitigating factor because the load increases of these customers allow the sale of the stranded capacity. CSW, on the other hand, opposes using the future load growth of remaining customers as a mitigation device. CSW states that the benefits of growth on the former supplier's system should flow to the customers who remain customers of that system. Ohio Ed agrees, except where the customer proves that the utility has deferred or cancelled capacity resource additions in response to departing customers.

Other commenters suggest that the Commission should not prescribe one method over the other.[FN834] EGA, for example, states that customers should have the choice of paying either a projected fixed amount or a charge that is periodically trued up.

Mitigation

A number of commenters agree that the revenues lost approach effectively encompasses mitigation.[FN835] Others argue that mitigation should (or could) be accomplished through divestiture of assets or capacity auctions.[FN836] LG&E states that a utility requesting recovery of stranded costs should be required to auction that portion of its system to the highest bidder. The difference between the auction price and the depreciated value of the auctioned assets could be used to determine stranded costs. However, LG&E does not advocate complete recovery of this difference; rather, it argues that this amount could be used as a starting point.

Several commenters argue that the revenues lost approach can produce anticompetitive results if capacity auctions or divestiture are not required.[FN837] A number of these commenters contend that utilities that recover significant stranded costs (while still maintaining control over the stranded capacity) can use the freed capacity to make sales in the market at subsidized prices. They maintain that these utilities do not have to worry about recovery of fixed costs because those costs are recovered by the stranded cost charge. According to these commenters, utilities can then remarket (or “dump”) stranded capacity at artificially low prices (made possible by the subsidy from the stranded cost recovery) and thereby gain a competitive advantage in other transactions.[FN838] If the utilities are permitted to remarket the displaced capacity, CA Energy Co states that market-sensitive floor prices should be set to prevent utilities from reselling power from stranded assets at artificially low prices.

Suggestions as to how to prevent such anticompetitive consequences include allowing the customer to own or control the residual asset or amount of stranded capacity equivalent to the lost revenues. According to EGA, the customer could market the capacity it would have had to pay for through stranded cost charges and thus prevent the utility from remarketing the capacity after it has been paid stranded costs.

Several commenters take a harder line and would require suppliers seeking stranded cost recovery to offer for sale to the departing customer a “slice” of their system.[FN839] TDU Systems states that the purchase of an undivided slice of the system is superior to divestiture of a specific asset because the utility cannot keep the wheat and leave the purchaser with the chaff. TDU Systems would also make purchase rights to the system assignable. According to TDU Systems, ***21657** this mitigation scheme is the only possible way to justify the revenues lost approach. TDU Systems argues that this proposal would inflict no harm on the utility, which would be fully compensated for the stranded assets. It also suggests that the ability to purchase a slice of the supplier's system would serve as an important bargaining tool in stranded cost negotiations, which would help level the playing field among the parties.

Other mitigation proposals include: (i) Requiring each utility to prepare a mitigation plan under the supervision of an independent expert that must be approved by the parties or by the Commission before stranded cost recovery is permitted; [FN840] (ii) requiring a utility to report annually for a five-year period its mitigation activities and to identify its stranded costs yet to be recovered;[FN841] and (iii) setting the market value of the displaced capacity at a high level (thereby reducing the stranded cost charge) to provide a mitigation incentive.[FN842] A number of commenters support customer-controlled mitigation, arguing, among other things, that the entity responsible for paying stranded costs has the best incentive to mitigate them.[FN843] Others support some form of utility sharing of stranded costs to give utilities an incentive to mitigate stranded costs.[FN844]

b. Reasonable Expectation Period (Period of Expected Continued Service)

Numerous commenters oppose setting absolute limits on the period over which a customer's liability for stranded costs would be determined.[FN845] They suggest instead that the Commission should apply the facts of each case, including the facts used to prove a reasonable expectation of continued service, to its determination of a reasonable expectation period. Among the factors commenters propose for consideration are: the utility's planning horizon; the average remaining life of the utility's generating facilities or a specific number of years that coincides with the duration of a utility-specific stranded cost recovery plan; utility projected load growth; dedicated facility construction lead times; estimated time to market stranded assets; the lesser of the utility's need date for new generation or the cross-over date when the market generation price is expected to equal a customer's embedded cost less other charges and compensation; and the period for which estimated revenues exceed market values. Commenters representing the financial community[FN846] oppose limiting cost recovery from the departing generation customer based on the term of the contract. They argue that it was reasonable for a utility to expect to continue to serve a customer, or customers who would take its place, through the life of the assets; otherwise, the asset could not have been financed in the first place.

A number of other commenters urge the Commission to prescribe limits on a customer's maximum liability.[FN847] Some commenters believe that the utility's planning horizon is the reasonable expectation period.[FN848] PSE&G states that since utilities invested and incurred costs to serve customers based on the planning horizon, the planning horizon is the only logical period. Other commenters propose that the reasonable expectation period be limited to one contract extension period, or to the shortest of: (i) One additional contract renewal period; (ii) the utility's planning horizon; (iii) the period it would/does take for load growth on the seller's system to absorb the lost load; or (iv) the contractual notice period.[FN849] Other suggested limits include the weighted average remaining life of all generating assets;[FN850] the in-service date of the utility's next avoidable generating unit or purchased power contract that is projected to have a capacity factor comparable to the departing generation customer's load factor minus a one-time mitigation effort;[FN851] and a rebuttable presumption that two years is the maximum time for a utility reasonably to expect to receive revenue from tariff sales or "open-ended" contracts.[FN852]

Other commenters propose recovery periods that range from three to five years (e.g., Central Montana EC),[FN853] five years (e.g., Public Power Council), and eight years (e.g., Allegheny).[FN854]

GA Com and AZ Com state that stranded cost recovery should not go on indefinitely. GA Com states that stranded costs should be collected for a sufficient period of time to ensure full recovery and indifference on the part of the utilities' remaining native load customers. AZ Com states that a specific termination period will also create an incentive for utilities to mitigate stranded costs.

c. Proposed Stranded Cost Recovery Procedures

Several commenters[FN855] urge the Commission to be flexible in evaluating proposed mechanisms for recovery of stranded costs, including the payment method, noting that an approach suitable to one utility and its customers may not be suitable to another. They say that utilities within a region might find a mechanism that meets their region's unique characteristics.

Some commenters oppose certain aspects of the procedures proposed in the NOPR. For example, TAPS objects that the NOPR procedure aimed at providing advance notice to the customer of its potential stranded cost obligation resembles the procedure rejected in Cajun. It says that "the customer will likely be forced to spend significant time and resources 'litigat[ing] to determine the price of a product(,)' thereby 'introduc[ing] deal-killing transactional costs and uncertainties."' (citing Cajun, 28 F.3d at 179). TAPS proposes that the seller be required to produce a stranded cost estimate that reflects a good faith, reasonable estimate of the likely impact of mitigation and that sellers making excessive and unsupported stranded cost claims be penalized. At a minimum, it argues that the seller should be held responsible for the costs ***21658** reasonably expended by the buyer to litigate the stranded cost claim.

DE Muni asserts that if filing a complaint to redress grievances related to the recovery of stranded costs is to be a meaningful remedy, the final rule should set a time limit within which the complaint must be resolved.

A number of commenters offer modifications to the recovery procedures set forth in the NOPR, including: (1) Extending a utility's response time for providing stranded cost liability estimates from 30 days to at least 60 days;[FN856] (2) requiring a utility to provide to each wholesale customer within six months of the effective date of the final rule: (a) The formula that the utility proposes to use to calculate the customer's maximum possible stranded cost exposure without mitigation; and (b) an actual calculation of the customer's stranded cost exposure assuming the customer left the utility's system six months after the effective date of the final rule;[FN857] (3) allowing customers that desire to litigate their stranded cost liability to do so in a forum in which all litigating customers participate;[FN858] (4) requiring utilities to disclose their estimated transition cost liabilities (and the nature of those liabilities) before the effective date of the final rule to permit a realistic evaluation of the scope of the transition cost problem and possibly facilitate resolution of some disputes by settlement;[FN859] (5) requiring any utility seeking stranded cost recovery to provide a list of the stranded facilities to the departing generation customer and offer that customer an equity position in those facilities in return for payment of stranded costs, thereby enabling the departing customer to recover some of its stranded costs payment when any of the facilities becomes useful again;[FN860] (6) requiring a "good faith request" for an estimate of stranded costs based on an expected date of departure from the providing utility's system and mitigation efforts expected to be undertaken by the utility;[FN861] and (7) requiring documented evidence that a utility made a good faith attempt to settle with a departing generation customer before the utility is given the opportunity to recover stranded costs.[FN862]

Commission Conclusion

We reaffirm our proposal that the determination of recoverable stranded costs should be based on the "revenues lost" approach. We find that the revenues lost approach is the fairest and most efficient way to balance the competing interests of those involved.

After careful consideration of the comments submitted, we have decided to adopt the following formula for calculating a departing generation customer's stranded cost obligation (SCO), on a present value basis, under a revenues lost approach:

SCO=(RSECMVEL

where:

RSE=Revenue Stream Estimate—average annual revenues from the departing generation customer over the three years prior to the customer's departure (with the variable cost component of the revenues clearly identified), less the average transmission-related revenues that the host utility would have recovered from the departing generation customer over the same three years under its new wholesale transmission tariff.[FN863]

CMVE=Competitive Market Value Estimate—determined in one of two ways, at the customer's option: Option (1)—the utility's estimate of the average annual revenues (over the reasonable expectation period "L" discussed below) that it can receive by selling the released capacity and associated energy, based on a market analysis performed by the utility; or Option (2)—the average annual cost to the customer of replacement capacity and associated energy, based on the customer's contractual commitment with its new supplier(s).

L=Length of Obligation (reasonable expectation period)—refers to the period of time the utility could have reasonably expected to continue to serve the departing generation customer. We reaffirm that we do not believe that a one-size-fits-all approach is appropriate for determining the length of a customer's obligation. If the parties cannot reach agreement as to the length of the customer's obligation, this period is to be determined through litigation as a part of the threshold issue of whether the utility had a reasonable expectation of continuing to serve the customer.

Application of the foregoing formula and collection of the resulting stranded costs are subject to the following conditions:

1. Cap on SCO. The quantity (RSE-CMVE) can be no greater than the average annual contribution to fixed power supply costs (defined as RSE less variable costs) that would have been made by the departing generation customer had it remained a customer.

2. Changes in Customer Revenues. If the customer's rates (or contract demand amounts, if relevant) changed during the three-year period prior to the termination of its existing requirements contract, then the RSE should be calculated using the customer's most recent 12 months of revenue.

3. CMVE Option 2 Conditions. Option 2 (a CMVE equal to the average cost to the customer of replacement capacity and associated energy) would be available to a customer whose alternative purchase(s) runs concurrent with L, or, if longer than L, contains rates that do not fluctuate over the duration of the contract. The customer would be required to demonstrate (at the time it chooses this option) that the replacement capacity contract(s) is for service equivalent to the released capacity (that is, firm power for a period at least equal to L), and must also clearly identify the rates to be paid for the replacement service.

4. Payment Options. The method and term of payment should be negotiated, but is ultimately left to the customer's discretion. Possible payment options include a lump-sum payment, an amortization of a lump-sum payment over a reasonable period of time, or a surcharge on the customer's transmission rate.

5. Applicability. The formula is designed for determining stranded costs associated with departing wholesale generation customers and for retail-turned-wholesale customers.[FN864]

6. Marketing/Brokering Option. The Commission will allow the customer, at its sole discretion, a choice to market the released capacity and associated energy (or to contract with a marketer for such service). Alternatively, the customer may choose to broker the released capacity and associated energy (or to contract with a broker).[FN865]

***21659** 7. Released Capacity and Associated Energy. A utility requesting stranded cost recovery must indicate the amount of system capacity and the amount of associated energy released by the departing generation customer and used in the revenues lost calculation. This will allow the departing generation customer to fairly consider exercising a choice to market or broker the released capacity and associated energy.

The formula balances a number of goals, including: (1) Ensuring full recovery of legitimate, prudent and verifiable stranded costs; (2) requiring the utility to mitigate stranded costs; (3) providing certainty for departing generation customers; and (4) creating incentives for the parties to renegotiate their existing requirements contracts or otherwise settle stranded cost claims without resort to litigation.

Contrary to the objections of some commenters that the revenues lost approach creates no incentive to mitigate stranded costs, the formula automatically encompasses mitigation by reducing the departing generation customer's stranded cost obligation by the competitive market value of the released capacity and associated energy. Further, the option provided in the formula for a customer to market or broker the released capacity and associated energy protects the customer from a utility trying to overrecover stranded costs by estimating a low value for the released capacity and associated energy and thereby provides the customer some assurance that stranded costs will be minimized. Specifically, if a customer believes the utility's competitive market value estimate (CMVE) is too low, it can market or broker the released capacity and associated energy and reduce its stranded cost obligation.[FN866] We accordingly will not impose a separate mitigation obligation on the utility above that which is already subsumed in the revenues lost approach. In addition, a utility will continue to be subject to an ongoing prudence obligation to sell excess capacity off-system and/or to dispose of uneconomic assets.

We recognize that some commenters oppose the revenues lost approach as imprecise. However, any ratemaking method that relies on estimates will be subject to forecasting error. Moreover, in direct response to commenter concerns, we have gone to great lengths in this rule to provide specificity with respect to the calculation of the components of the formula. We believe that use of the formula will narrow the scope of disputes over the calculation of stranded costs, lend precision to the stranded cost amount it produces, and provide certainty to departing generation customers with respect to their stranded cost obligations.

Calculation of the Revenue Stream Estimate (RSE)

The RSE component of the formula is based on revenues paid by the departing generation customer during the last three years of its contract or retail service. We believe that the use of "present" revenues in the calculation of the revenue stream has numerous advantages over other approaches advocated. The use of present revenues eliminates disputes over estimates of future revenues, thereby adding certainty to the calculation. It also eliminates the need for a detailed listing of includable costs, relying instead on the assumption that present rates include all of the utility's costs of providing service. Further, the rates that produce present revenues have been approved by regulators, which strongly suggests that the costs included in them are prudent, legitimate and verifiable.[FN867]

We reject the suggestion by commenters that a utility be required to calculate the revenue stream using any lower rate being offered by the utility for service comparable to that being taken by the customer when the customer departs the utility's generation system. A revenue stream calculated in this manner could deny a utility the opportunity to fully recover its stranded costs or could shift costs to other customers, a result we find unacceptable. Similarly, the elimination of return-related revenues from the revenue stream effectively would require shareholders to absorb stranded costs, which is contrary to our determination that a utility is entitled to an opportunity to fully recover legitimate, prudent and verifiable stranded costs.

Calculation of the Competitive Market Value Estimate (CMVE)

We recognize the difficulty associated with estimating the competitive market value of the capacity and associated energy not purchased by the departing generation customer. However, we believe that an up-front estimate, which provides flexibility to the utility and a measure of certainty to customers, is superior to other proposals, provided the right mix of incentives and options is included in the formula.

A utility requesting stranded cost recovery must estimate CMVE based on a market analysis, with all assumptions and work papers made available to the departing generation customer. This provides a utility with the flexibility to choose the methodology that it feels produces the best estimate of the competitive market value of the released capacity and associated energy. We note that numerous proposals for calculating competitive market value were made in the comments. The Commission believes that the flexibility provided by the formula we adopt in this Rule permits the filing utility to avail itself of many of these recommendations.

At the same time, a utility may have an incentive to underestimate CMVE and thereby increase the stranded costs charge. To address this issue, the formula contains several features designed to create an incentive to produce a good faith estimate of stranded costs and to safeguard customers if a utility fails to do so. For example, the formula provides a departing generation customer with the option to market or broker the released capacity and associated energy if it believes the utility's estimate is too low. If the marketing option is chosen, the customer would buy the released capacity from the utility at the utility's market value estimate. The associated energy would be purchased at the utility's average system variable cost. The customer would then resell the released capacity and energy and keep the resulting revenues. If the revenues it receives are greater than the utility's market value estimate, the customer will have reduced its stranded cost obligation. If the customer chooses the brokering option and the released capacity and associated energy are purchased by a third-party for more than the utility's market value estimate, the difference between the average annual revenues produced by the sale and the utility's CMVE estimate will be used to lower the customer's stranded cost obligation. The utility may be required to show in a compliance filing that it has reduced the customer's stranded cost obligation under such circumstances.

If the customer chooses CMVE Option 2 and meets its conditions, CMVE will be set at the average price that the customer pays its new supplier. The customer will test the market and choose the best deal available. Hence, ***21660** the price the customer pays its alternative supplier is arguably a more accurate measure of the competitive market value of the capacity and associated energy not taken from the host utility. Whether to exercise Option 2 resides solely with the customer.

We further note that the sale of all or part of a utility's generating assets could be used as a method to determine competitive market value of such assets. Under the theory that an asset sale price reflects the highest value for the utility's assets, the Commission would presume that the competitive market value established under an open asset sale (i.e., an offer to sell assets to any taker) would fully satisfy the utility's responsibility to minimize stranded costs. If a stranded cost claim involves divestiture of assets, the amount of stranded costs associated with those assets would be the book value less the sale price. The Commission would determine the appropriate stranded cost charge based on the facts presented.

Snapshot Approach Versus True-Ups

The revenues lost formula is based on a one-time snapshot approach. We favor this approach over the true-up approach because it creates certainty and will produce reasonably accurate results. True-ups, on the other hand, while theoretically more accurate, require periodic recalculation of stranded costs, which creates ongoing uncertainty and disputes. In addition, true-ups will result in additional transaction costs. We believe that an approach that provides certainty and establishes cost responsibility up front is best for what is fundamentally a transition issue.

Implementation Procedures[FN868]

In the Supplemental Stranded Cost NOPR, we proposed procedures to provide a potential departing generation customer with advance notice of how the utility would propose to calculate costs that the utility claims would be stranded by the customer's departure.[FN869] These procedures are modified as follows to incorporate the findings made in this rule:

(1) A customer may, at any time before the termination date specified in its existing wholesale requirements contract,[FN870] request the public utility to provide an estimate of the customer's stranded cost obligation based on the revenues lost formula contained in this Rule,[FN871] as of the date set forth in the customer's request. The customer should specify in its request, to the extent possible, pursuant to its rights under its power sales requirements contract with the seller,[FN872] the date on which the customer is considering substituting alternative generation for the requirements purchase and the amount of the substitute generation. Any remaining generation requirements to be purchased from the existing supplier after this date should be clearly indicated. The customer may seek further information on how the stranded cost charge would vary as a result of choosing different dates or different amounts of substitute purchases. The customer also should indicate its preferred payment method, such as a lump-sum payment, an amortization of a lump-sum payment, or a surcharge (such as monthly or annual) on the customer's transmission rate.

(2) The utility shall, within thirty days of receipt of the request, or other mutually agreed-upon period, provide the customer with an estimate of the customer's stranded cost obligation. The response shall include: (i) Estimates of RSE, CMVE, and L according to the revenues lost formula and based on the information supplied by the customer; (ii) supporting detail (including the underlying market analysis that forms the basis for the CMVE estimate) indicating how each element in the formula is derived to enable the customer to understand the basis for each element; (iii) a detailed rationale justifying the basis for the utility's reasonable expectation of continuing to serve the customer beyond the termination date in the contract;[FN873] (iv) an estimate of the amount of released capacity and the amount of associated energy that would result from the customer's departure, based on the information supplied by the customer, including detailed support for the amount of the released capacity and the amount of associated energy, and the market value of each, for each year of the reasonable expectation period, and how those amounts are consistent with the RSE and CMVE estimates; and (v) the utility's proposal for any contract amendment needed to implement the customer's payment of stranded costs (the proposed modification should also reflect the customer's chosen payment method).

(3) If the customer believes that: (i) The utility has failed to establish that it had a reasonable expectation of continuing to serve the customer beyond the contract term;[FN874] (ii) the proposed stranded cost charge (or any of the elements used to compute it) is unreasonable; (iii) the amount of released capacity and the amount of associated energy assumed to be sold is unreasonable; or (iv) the utility's proposal for any contract amendment needed to implement the customer's payment of stranded costs is unreasonable, the customer will have thirty days in which to respond to the utility explaining why it disagrees. The Commission expects parties to attempt to resolve any disputed issues.

(4) If the parties are unable to resolve the matter using the procedures in (1)-(3) above, the customer may either: (a) File a petition for declaratory order, or a section 206 filing seeking to amend an existing requirements contract, to seek a Commission determination as to whether: (i) The utility has met the reasonable expectation standard; (ii) the proposed stranded cost charge satisfies the other evidentiary standards set forth in this Rule; (iii) the amount of released capacity and the amount of associated energy proposed by the utility is reasonable; or (iv) the utility's proposal for any contract amendment needed to implement the customer's payment of stranded costs is reasonable; or (b) wait until the proposed stranded cost charge is filed by the utility under section 205 of the FPA, and contest it at that time.[FN875] In either case, because estimates of RSE and CMVE may change over time, any estimate of ***21661** stranded costs provided by a utility to a customer will not be considered binding prior to any filing by either party with the Commission. However, any stranded cost estimate filed by the utility in a section 205 or 206 proceeding, or in response to a petition for a declaratory order, shall be considered to be a binding estimate of the customer's maximum stranded cost obligation for purposes of litigation. Similarly, any estimate of stranded cost obligation filed by a customer in a petition for declaratory order or a section 205 or 206 proceeding shall be considered to be a binding estimate of the customer's minimum stranded cost obligation for purposes of litigation.[FN876] Estimates of stranded cost obligation that are filed by either party with the Commission shall include the information, including the supporting detail, identified in (2) above.

(5) If a utility intends to file for stranded cost recovery from a customer through either a stranded cost amendment to its existing contract or a surcharge on transmission rates, it must file its stranded cost estimate no later than 120 days prior to the end of the customer's contract term. The filing shall include the information, including the supporting detail, set forth in (2) above. The customer, of course, may contest the contents of such a filing.[FN877]

Conditions of the Marketing/Brokering Option

A customer may choose to market or broker a portion or all of the released capacity and associated energy identified by the utility in its stranded cost estimate (or to contract with a marketing/brokering agent). Importantly, by exercising the marketing or brokering option, the customer does not relinquish its right to contest any aspect of the utility's stranded cost estimate, including whether the utility is entitled to recover stranded costs for the period that the customer has agreed to market or broker any released capacity and associated energy. To implement this option, a customer must inform the utility in writing of its decision no later than 30 days after the utility files its estimate of stranded costs for the customer with the Commission. Before marketing or brokering of the released capacity and associated energy can begin, the utility and customer must execute an agreement identifying, at a minimum, the amount of capacity and associated energy the customer is entitled to schedule, the price of capacity and associated energy, and the duration of the customer's marketing/brokering of the released capacity and associated energy. Parties are encouraged to settle disputes over these and any other marketing/brokering implementation issues. The negotiations should be guided by the principle that the utility must allow the customer to market or broker the released capacity and associated energy under terms and conditions comparable to those for a utility resale of the capacity and associated energy to a third party. If agreement over marketing or brokering cannot be reached, the parties may seek to include the issue as a part of a proceeding initiated at the Commission with respect to the utility's stranded cost estimate for the customer.[FN878] Upon issuance of an order resolving the disputed issues, the customer may reevaluate its decision to exercise the marketing/brokering option. The customer also may choose to market or broker any released capacity and associated energy not being marketed or brokered under an earlier agreement with the utility. A customer must notify the utility in writing within 30 days of issuance of the Commission's order resolving the disputed issues whether the customer will market or broker a portion or all of the capacity and energy associated with stranded costs allowed by the Commission.

Payment for Released Capacity and Associated Energy Under the Marketing Option
If the customer chooses to market released capacity and associated energy, it shall pay the utility's estimate of the competitive market value of the capacity, or, if the marketing option is exercised after a Commission order, it shall pay the competitive market value amount as determined by Commission order. In addition, for all energy scheduled to be delivered, the customer shall pay the utility's average system variable costs. The customer may also choose to market only a portion of the released capacity and/or for a shorter period. In this situation, the customer will also pay the competitive market value for the released capacity plus the utility's average system energy costs. The customer's liability for payment of stranded costs is unaffected by its decision to market released capacity and associated energy.[FN879] In addition, to the extent that the customer chooses to market a portion or all of the capacity alleged by the utility to be stranded, a final determination with respect to the customer's stranded cost obligation will not affect any prior marketing agreement.

Payment for Stranded Costs Under the Brokering Option
If the customer chooses to broker a portion or all of the released capacity and associated energy, any revenue received from such brokering activity shall be used to offset the utility's estimate of the competitive market value of the brokered capacity and associated energy.[FN880] Once a brokering agreement is executed between the customer and the utility, if the customer's brokering efforts fail to produce a buyer within 60 days of the date of that agreement, the customer shall relinquish all rights to broker the released capacity and associated energy and will pay stranded costs as determined by the formula.

***21662 10. Stranded Costs in the Context of Voluntary Restructuring**
In the Supplemental Stranded Cost NOPR, we noted that the functional unbundling of wholesale services does not require corporate unbundling (such as disposition of assets to a non-affiliate, or establishing a separate corporate affiliate to manage a utility's transmission assets). At the same time, we indicated that some utilities may ultimately choose some form of corporate unbundling.[FN881] We reaffirm in this Final Rule that we are willing to consider case-specific proposals for dealing with stranded costs in the context of any restructuring proceedings that may be instituted by individual utilities.

11. Accounting Treatment for Stranded Costs Comments
A number of commenters ask the Commission to provide accounting treatment guidance as part of its procedures for implementing its policies on stranded costs and their recovery.[FN882]

NSP states that the Commission will need to provide appropriate accounting guidance for the final stranded cost recovery methodology, including accounting for any portion of stranded cost recovery representing capital costs, the effect of any interperiod differences between the stranded cost calculations and the authorized recovery period, and the effects of differences between book and income implications of the stranded cost recovery mechanism. NSP also asserts that, in addressing the accounting implications of the final rule, the Commission must consider the requirements of the Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards No. 121, “Impairment of Long-Lived Assets” (SFAS No 121).

NASUCA states that one of the Commission's stated goals in providing stranded cost recovery is to protect against cost shifting. NASUCA argues that the Commission should adopt an accounting rule that assures that any federal resolution of wholesale stranded costs does not impose any cost shifting to captive customers.

EEI and Centerior argue that the Uniform System of Accounts as presently configured does not support the Commission's proposed policies on stranded cost recovery. Further, EEI states that even with the revenues lost approach, which EEI supports, utilities will still have to account for their assets on a class-of-asset by class-of-asset basis. EEI argues that this is necessary to ensure that the costs of the assets are expensed in the proper accounting period. EEI states that one of the basic principles of financial accounting is that expenses should be matched with the related revenues.

Commission Conclusion

As discussed in Section IV.J.3, this rule adopts a direct assignment approach for the recovery of stranded costs from departing generation customers. Under the revenues lost approach, stranded cost recovery is limited to the departing generation customer's contribution to fixed costs that the utility otherwise would not recover because of the customer's departure.

We recognize that there are certain similarities between the financial reporting objectives of SFAS No. 121 and the determination of stranded costs. However, there are also important differences between SFAS No. 121 and our approach to stranded costs. The revenues lost approach does not attempt to identify specific uneconomic assets and is not limited to only long-lived assets. Instead, it uses a formulary methodology that encompasses all fixed costs of providing service.

From a financial accounting standpoint, our approach to stranded costs creates the potential for a mismatch between the periods in which the stranded costs are charged to expense and any revenues provided for their recovery are included in net income determinations. This is because the earning process entitling a utility to the benefits of stranded cost recovery and thereby requiring the recognition of revenue may be completed prior to the time that the stranded costs must be charged to expense under generally accepted cost recognition criteria. This circumstance in a cost-based regulated environment creates the undesirable potential for double recovery of the same cost, cost shifting, and inappropriate financial reporting.

In order to avoid this potential, utilities shall not recognize revenues intended to provide for recovery of stranded costs from wholesale requirements customers prior to the time that the stranded costs are charged to expense, unless prior Commission approval to do so has been obtained. Absent Commission approval, utilities shall defer such amounts in Account 253, Other Deferred Credits, and amortize them to Account 456, Other Electric Revenues, consistent with the period the related costs are charged to expense. Also, we will require a utility to submit its proposed accounting for stranded costs and related revenues as part of its rate filing requesting recovery of stranded costs under section 205 of the FPA.

12. Definitions, Application, and Summary

In the Supplemental Stranded Cost NOPR, the Commission described proposed amendments to our regulations to establish filing requirements for public utilities and transmitting utilities that seek stranded cost recovery. We proposed to define "wholesale stranded cost" as "any legitimate, prudent and verifiable cost incurred by a public utility or a transmitting utility to provide service to: (i) A wholesale requirements customer that subsequently becomes, in whole or in part, an unbundled wholesale transmission services customer of such public utility or transmitting utility, or (ii) a retail customer, or a newly created wholesale power sales customer, that subsequently becomes, in whole or in part, an unbundled wholesale transmission services customer of such public utility or transmitting utility." We sought comments on whether this definition should encompass the situation where a wholesale requirements customer ceases to purchase power from the utility that had been making wholesale requirements sales to such customer without becoming an unbundled transmission services customer of that utility.[FN883]

Comments

We received numerous comments both supporting and opposing revisions to the proposed definition of wholesale stranded costs.[FN884] Several commenters oppose broadening the definition to include costs stranded by customers that do not become unbundled transmission service customers of the former supplier.[FN885] For example, EGA argues that the loss of an industrial customer that chooses to self-generate or the loss of a requirements customer as a result of a newly-created municipal system that interconnects with a transmitting utility that is not the customer's former supplier could have happened at any time. EGA states that revenues lost as a result of either ***21663** scenario have nothing to do with regulatory reforms and should not be considered "stranded" costs.

Other commenters disagree.[FN886] Puget asserts that permitting departing generation customers to avoid paying stranded costs if they do not take unbundled transmission from their former suppliers would create an incentive for departing customers (or their new electric suppliers) to build unneeded and uneconomic new transmission lines. Puget says that it also could be a disincentive to engage in regional transmission planning and coordination because the existence of new transmission facilities needed to achieve regional reliability and efficiency may increase the likelihood that departing generation customers could import their power supplies over those new facilities and avoid paying the utility's stranded costs.[FN887]

Some of these commenters propose using an exit fee to collect stranded costs from a customer that does not take unbundled transmission from its former supplier, since a transmission surcharge is not available in this circumstance.[FN888] Other methods proposed include: (1) Conditioning Commission approval of the transmission rates or wholesale power rates charged by the transmission-providing utility upon the inclusion of a surcharge to recover the former supplier's stranded costs or upon the transmission-providing utility otherwise agreeing to guarantee the payment of the stranded costs or act as billing agent for the former supplier;[FN889] (2) authorizing the former supplier to levy a stranded cost charge on the transmission-providing utility (if that utility is interconnected with and has transmission contracts with the former supplier); (3) if a retail customer becomes annexed to a municipal utility and does not take unbundled transmission services from its former supplier, permitting recovery of stranded costs from the municipal utility through its jurisdictional transmission rates; or (4) requiring a public utility providing transmission service for a customer that has left its former supplier to agree, as a condition to recovery of its own stranded costs, to ensure the payment of any stranded costs incurred by the former supplier.[FN890]

Commenters also address the use of the terms "legitimate, prudent, and verifiable" in the definitions of wholesale and retail stranded costs. Several commenters suggest that the Commission's use of the word "prudent" could imply that utilities have to relitigate the prudence of costs that the Commission and state commissions have already approved; these commenters believe that utilities should not have to relitigate prudence.[FN891] Some argue that once a regulatory agency (state or federal) has allowed recovery of the costs in rates, or promised future recovery, utilities should not have to undergo a second regulatory review to recover those costs if they become stranded.[FN892]

Commenters recommend that the Commission address this situation by: Striking the word "prudent" from the definition or specifying that the prudence requirement is satisfied by previous regulatory authorization;[FN893] dropping the terms "legitimate, prudent and verifiable" from the definition and using instead "allowed," "accepted," or "allowable";[FN894] or adding "or approved by state commission" after the words "legitimate, prudent and verifiable" in the definitions of both wholesale and retail stranded costs.[FN895]

Other commenters oppose these proposals, suggesting that the prudence analysis for stranded cost purposes may involve questions of prudence different from those that arise in a ratemaking context.[FN896] DE Muni objects that replacing "legitimate, prudent and verifiable" with "allowed, accepted, or allowable" could enable a utility to recover costs that the utility may not be able to prove were prudent, legitimate, and verifiable.

A number of commenters submit that "legitimate, prudent and verifiable" costs should not include the costs of uneconomic plants or costs resulting from utilities' independent business decisions (as distinguished from costs the utility was forced by regulation to incur).[FN897]

Several other commenters address the rule's application to wholesale requirements customers.[FN898] AMP-Ohio asks the Commission to clarify that the reference to "wholesale requirements customer" is to a full requirements customer, not a partial requirements customer. It says that no transmission provider should have any reasonable expectation of continuing to serve loads of partial requirements customers. TAPS suggests that references to "new wholesale requirements contract" in proposed §35.26(c)(1) should be conformed to the defined term "new contract" in proposed §35.26(b)(7). In addition, it suggests that the Commission clarify the regulations by clearly foreclosing stranded cost claims for "new contracts" without express exit fees, instead of simply failing to provide for such recovery.

Commission Conclusion

We will retain the definition of "wholesale stranded cost" proposed in the Supplemental Stranded Cost NOPR.[FN899] We believe it would be inappropriate to expand the definition to include the situation where a ***21664** wholesale requirements customer[FN900] (or a retail-turned-wholesale customer) ceases to purchase power from the utility without using the transmission services of that utility.[FN901] Any costs that the utility might incur as a result of the loss of the requirements customer in this scenario would be outside the scope of this Rule. The premise of this Rule is that, where a customer uses the new open access to obtain power from a new generation supplier, the customer must pay the costs that were incurred on its behalf under the prior regulatory regime. However, if a customer leaves its utility supplier by exercising power supply options (such as access to another utility's transmission system or self-generation) that do not rely on access to the former seller's transmission, there is no nexus to the new open access rules.[FN902] If a customer is able to obtain power from a new supplier by using the transmission system of another utility, it is likely that the customer could have made these arrangements in the absence of the new open access rules. The new transmission provider would have had little incentive to deny transmission services to the customer in order to protect an existing power supply arrangement, since it was not the customer's power supplier in the first place. Indeed, it is likely that the neighboring utility would have a positive incentive to provide the transmission service in order to increase its revenues. This incentive is unchanged by open access transmission.

Some commenters have asked us to eliminate the term "prudent" from the definition of stranded costs. We will not do so; we will retain the requirement that stranded costs be "legitimate, prudent and verifiable." A determination that a utility had a reasonable expectation of continuing to serve a customer would not, in all circumstances, mean that costs incurred by the utility were prudent. Prudence of costs, depending upon the facts in a specific case, may include different things: e.g., prudence in operation and maintenance of a plant; prudence in continuing to own a plant when cheaper alternatives become available; prudence in entering into purchased power contracts, or continuing such contracts when buy-outs or buy-downs of the contracts would result in savings. The Commission therefore cannot make a blanket assumption that all claimed stranded costs will have been prudently incurred. However, we clarify that we do not intend to relitigate the prudence of costs previously recovered.[FN903]

Thus, this Rule will permit a public utility or transmitting utility to seek recovery of wholesale stranded costs as follows. First, for stranded costs associated with new wholesale requirements contracts (that is, any wholesale requirements contract executed after July 11, 1994), the regulations will allow recovery of stranded costs only if the contract contains an explicit stranded cost provision that permits recovery. By "explicit stranded cost provision" we mean a provision that identifies the specific amount of stranded cost liability of the customer(s) and a specific method for calculating the stranded cost charge or rate.. We clarify that provisions in requirements contracts executed after July 11, 1994 but before the date on which this Final Rule is published in the Federal Register that explicitly reserved the right to stranded cost recovery pending the outcome of this Rule will be deemed "explicit stranded cost provisions." However, provisions in requirements contracts executed after July 11, 1994 but before the date on which this Final Rule is published in the Federal Register that postpone the issue of stranded cost recovery without specifically providing for recovery of stranded costs will not be considered "explicit stranded cost provisions."

Second, for existing wholesale requirements contracts (that is, any wholesale requirements contract executed on or before July 11, 1994), a utility may not recover stranded costs if recovery is explicitly prohibited by the contract (including associated settlements) or by any power sales or transmission tariff on file with the Commission.

Third, for existing wholesale requirements contracts that do not address stranded costs through exit fee or other explicit stranded cost provisions, a public utility may seek recovery of stranded costs only as follows: (1) If the parties to the existing contract renegotiate the contract and file a mutually agreeable amendment dealing with stranded costs, and the Commission accepts or approves the amendment; (2) if either or both parties seeks an amendment to the existing contract under sections 205 or 206 of the FPA, before the contract expires, and the Commission accepts or approves an amendment permitting stranded cost recovery; or (3) if the public utility files a request, before the contract expires, to recover stranded costs through a departing generation customer's transmission rates under FPA sections 205-206 or 211-212.

Fourth, if the selling utility under an existing wholesale requirements contract is a transmitting utility but not also a public utility, and the contract does not address stranded costs through an explicit exit fee or other stranded cost provision, the transmitting utility may seek to recover stranded costs through a surcharge to a departing generation customer's transmission rates under

FPA sections 211-212. Such utility may not seek recovery of stranded costs through a section 211-212 transmission rate if the existing requirements contract does contain an explicit exit fee or other stranded cost provision.

Fifth, for a retail-turned-wholesale customer, a public utility or transmitting utility may file a request to recover stranded costs from the newly-created wholesale customer through that customer's transmission rates under FPA sections 205-206 or 211-212.

Sixth, for customers who obtain retail wheeling, a public utility or transmitting utility may seek recovery through Commission-jurisdictional transmission rates only if the state regulatory authority had no authority under state law to address stranded costs when retail wheeling is required.

***21665** *K. Other*

1. Information Reporting Requirements for Public Utilities

In the NOPR, the Commission did not propose any changes to its information filing requirements for public utilities.

Comments

Many IOUs argue that the current information filing requirements competitively disadvantage traditional public utilities and unfairly benefit sellers, such as power marketers, that are not required to provide comparable information.[FN904] They urge the Commission to eliminate the requirement for public disclosure of competitively sensitive, proprietary, or otherwise confidential Form No. 1 data. They contend that requiring such disclosure only from traditional public utilities harms such public utilities and compromises the development of efficient competition. Illinois Power asks the Commission to review all information that utilities must file, including EIA 860, EIA 767, and FERC Form No. 715.

A number of commenters believe that some type of information requirement must also be placed on non-public utility entities.[FN905] PacifiCorp suggests that the Commission should require transmitting utilities that do not file a Form No. 1 to file similar information annually with the Commission. Ohio Edison asserts that the Commission should extend its use of the reciprocity concept to require the filing of operating data with the Commission. Further, if non-public utility entities are not required to disclose certain information, Ohio Edison asserts that all public utilities that have received approval to sell power at market-based rates, including traditional utilities, should also be free from having to disclose such information.

Arizona argues that enforcing comparability vis-a-vis non-public utility transmitting utilities would seem to invite jurisdictional challenge. Thus, it would support legislation to broaden the Commission's jurisdiction.[FN906]

Commission Conclusion

We will not adopt the suggestion made by a number of commenters that we now eliminate the public disclosure of allegedly competitively sensitive, proprietary, or otherwise confidential data submitted to the Commission on Form No. 1, as well as on other Commission forms. The information that we collect from public utilities is necessary to carry out our jurisdictional responsibilities and is used, among other things, to evaluate the reasonableness of cost-based rates subject to our jurisdiction and the operation of power markets.[FN907] Moreover, as we explained in ConEd,

[R]eports required to be submitted by Commission rule and necessary for the Commission's jurisdictional activities are considered public information. 18 CFR 388.106. In addition, the Commission has long required jurisdictional utilities to submit Form 1 data on a form that states on its cover that the Commission does not consider the material to be confidential.[FN908]

We are sensitive to the lack of symmetry in the generation information we require from traditional public utilities, particularly those that have market-based rate authority, and the generation information we require from other public utilities (e.g., public utility marketers) authorized to sell at market-based rates.[FN909] However, the record in this proceeding is insufficiently developed for us to make and support a well-informed decision requiring a different reporting scheme, particularly given the industry's current rapid pace of change. Also, we are not persuaded that the burdens borne by traditional public utilities (primarily annual reports submitted months after-the-fact) are impairing the competitiveness of these utilities so much that we must act hastily now, instead of deferring a decision to a more appropriate proceeding. Moreover, we are required to regulate the rates of public utilities and, although we are moving toward greater reliance on market-based generation rates, we continue to regulate generation on a cost basis for most traditional public utilities, particularly rates for sales from existing generation. To assure that these rates are just and reasonable, we, as well as the customers of public utilities, need the more detailed information our regulations require public utilities to submit.

Accordingly, at this time, we will not change our information reporting requirements. As the industry becomes more competitive, we will monitor our reporting requirements to make sure that they are needed, fair to all segments of the industry, and consistent with the workings of a competitive environment.

2. Small Utilities

In the NOPR, we did not address whether special provisions were needed for small public utilities and small transmission customers because of the possible burden of unbundling, open access tariffs, and the OASIS requirement.

Comments

A number of commenters assert that the unbundling requirement poses significant problems for smaller public utilities and that small utilities should not be subject to the same requirements as larger utilities.[FN910] St. Joseph notes that in small utilities one system operator typically runs the system operations center. Functional unbundling, it asserts, would require the addition of another operator for each shift at great cost to the small utility. Central Hudson estimates that unbundling would result in an approximately 10 percent increase in the wholesale price, putting small utilities at a competitive disadvantage.

Several commenters assert that many small utilities enjoy little or no transmission market power because their systems tend to be in parallel with large systems and are bypassed as a result. They say that customers prefer to deal with one large regional utility rather than pay pancaked transmission rates for service through two or more small utilities.

Citizens Utilities argues that some systems are radial spurs of much larger systems and merely serve to link points of interconnection. It claims that a network tariff is not applicable in such a case and that it is unlikely that third parties would request service over such small or isolated systems. It recommends that if a utility is basically a spur system and faces little present or future demand for third-party service, the Commission should either relax the open access requirements or defer them until a section 211 request is submitted.

East Kentucky proposes that the Commission exempt not-for-profit utilities from the requirement to separate the functions related to operation and marketing, since small G&T cooperatives exist solely to serve the needs of their owner-member distribution cooperatives.

***21666** VT DPS suggests that waiver of marketing and transmission personnel separation requirements may be appropriate in the case of smaller utilities that do not operate control areas. St. Joseph proposes that the Commission establish a threshold level based on system demand of 1000 MW, below which unbundling of wholesale transmission functions from other dispatching functions would not be required. Alternatively, St. Joseph proposes an exemption from unbundling where the utility can demonstrate that it has no market power and that unbundling would not materially improve the level of competition in the generating market.

Central Hudson believes that the Commission should allow the development of a short form tariff or else defer the functional unbundling requirement for smaller utilities and use the section 211 process in the interim to provide flexibility for these utilities.

Oregon Trail EC, a small rural electric, public utility cooperative, requests that the Commission revise proposed §35.28 of its regulations to provide that the generic open access transmission requirements apply only to public utilities that operate facilities used for the transmission of electric energy in interstate commerce. It explains that it owns one transmission line that it leases to BPA, which operates the line as part of its integrated transmission network. Thus, Oregon Trail EC states that it cannot meet the requirements of the open access rule. It also points out that the Commission exempted Oregon Trail EC and other similarly situated utilities from the transmission reporting requirements of Form No. 715 because they did not engage in transmission planning.

ALCOA suggests that the default tariffs for smaller utilities with transmission systems unlikely to be used by others should not become effective automatically. Rather, the default tariffs should become effective only when service is requested. Citizens Utilities suggests that relaxed tariff requirements be established for small utilities with insignificant demand for transmission service.

BG&E believes that a utility using its system on a network basis for economic dispatch should not be required to file a network service tariff if there is no customer to take the service. It suggests that if municipalization were to occur, the Commission could then require the utility to file, within 60 days, a network service tariff to serve the new municipal.

Commission Conclusion

We are sympathetic to the array of concerns raised by small public utilities and small transmission customers. The regulations we are adopting include waiver provisions under which public utilities and transmission customers, and non-public utility entities seeking exemption from the reciprocity condition, may file requests for waivers from all or part of the Commission's regulations or for special treatment.[FN911] However, it is difficult to imagine any circumstance that would justify waiving the requirements of this Rule for any public utility that is also a control area operator.

We recognize, for example, that it might be a financial burden on small public utilities to unbundle generation from transmission, follow standards of conduct that separate transmission personnel from wholesale marketing personnel, and maintain an OASIS. These requirements may be particularly burdensome for small public utilities that own no generation and buy at wholesale on a radial transmission line from another utility's grid. In addition, if a small public utility's service territory is part of another utility's control area, the small public utility should be permitted to make a showing that it should be exempt from all or some of the Rule. In this circumstance, we will consider granting a waiver if the utility can show that: (1) It does not own transmission facilities, (2) it has turned control of its facilities over to someone else (such as the control area operator) who complies with the rule as its agent, or (3) no one is likely to ask to use its facilities (e.g., because they are radial lines), and it commits to file an open access tariff within 60 days of a request to use its facilities and to comply with the rule in all other ways.

Because the possible scenarios under which small entities may seek waivers from the Final Rule are diverse, they are not susceptible to resolution on a generic basis and we will require applications and fact-specific determinations in each instance. We note here that any waivers that we may grant depend upon the facts presented in each case. If the circumstances that give rise to the exemption change, the waiver may no longer be appropriate. For example, a radial line today could very easily become part of a network tomorrow and a portion of a grid that no one is interested in using today could become an important transmission link tomorrow, especially if retail access is allowed.

In addition, we will apply the same standards to any entity seeking a waiver. This includes public utilities seeking waiver of some or all of the requirements of the rule, as well as non-public utilities seeking waiver of the reciprocity provisions contained in the pro forma open access tariff. Thus, we would not apply the open access reciprocity provision to small non-public utilities that are not control area operators and either do not own or control transmission or have transmission that no one is likely to ask to use. They would not have to provide an open access tariff, establish an OASIS, or separate operators of transmission from wholesale purchasers in order to satisfy the reciprocity condition for obtaining transmission service. However, they will have to apply for this waiver and demonstrate that they qualify for the waiver.

3. Regional Transmission Groups

In the NOPR, we again expressed our support for the voluntary formation of regional transmission groups (RTGs).[FN912] We also explained that the potential benefits of RTGs would not be undermined by the rules proposed in the NOPR.

a. Incentives for RTGs to Form and Resolve Regional Transmission Issues

Comments

A number of commenters urge the Commission to provide incentives for the formation of RTGs within two years of the adoption of the final rule.[FN913] Several commenters argue that the Commission should encourage a regional approach to transmission issues by expanding the role of RTGs.[FN914] Com Ed also claims that contract path pricing problems probably will need to be resolved at the regional level.

Sierra Pacific Power, which views open access as the major benefit of RTGs, questions the need to provide incentives for the development of RTGs once open access is implemented. However, it does see that RTGs may help promote open access with non-public utility entities, who have shown ***21667** an increased interest in joining RTGs. American Wind and MT Com request that the Commission adopt policies that will encourage a close working relationship between RTGs and state authorities.

Otter Tail contends that the final Rule should stop short of establishing any conditions on the formation, governance, or functions of RTGs, arguing that such issues are complex and outside the scope of the NOPR. ALCOA and Missouri Joint Commission encourage the Commission to make certain that its policy regarding RTGs is not implemented in a manner that conflicts with the new open access regime.

Commission Conclusion

We continue to support the development of RTGs and encourage the formation of regional tariffs.[FN915] In our Policy Statement Regarding Regional Transmission Groups, we first explained our support for such voluntary associations.[FN916] We again explained our support in the NOPR:

We believe that RTGs can speed the development of competitive markets, increase the efficiency of the operation of transmission systems, provide a framework for coordination of regional planning of the system and reduce the administrative burden on the Commission and on members of RTGs by providing for voluntary resolution of disputes.[FN917]

To further encourage the development of RTGs, we will accept regional open access transmission tariffs developed by RTGs that are consistent with the objectives of this Rule. This should make it easier for all parties in a region to coordinate their activities.

b. Deference to RTGs To Develop Regional Tariffs and Prices

Comments

A number of commenters urge the Commission to give considerable deference to RTGs on such issues as the formulation of pricing methods and RTG member duties.[FN918] Nebraska Public Power District requests that the Commission consider permitting a megawatt-mile pricing mechanism for MAPP. NWRTA urges the Commission to define clearly how much deference it will accord to RTGs and explicitly grant deference to RTGs on such matters as dispute resolution and decisionmaking processes. It also asks that the Commission honor the reciprocity provisions related to Canadian participation that are contained in the NWRTA agreement. Nevada Power requests the Commission to accept, as not unduly discriminatory, RTG open access tariffs that reflect the members' specific terms and conditions so long as the tariffs satisfy the substantive requirements of the final rule. It proposes that such tariffs be allowed to become effective without hearing or refund obligation.

Texas-New Mexico, while encouraging deference to RTGs in general, argues that deference must be conditioned upon a requirement that the RTG provide not only equal access but also terms and conditions of service that are comparable to what a customer could otherwise obtain under the final Rule tariff or under section 211 of the FPA.

Southwest TDU Group contends that RTGs should not be given deference, and RTG filings should be subject to the same standards and scrutiny as non-RTG filings.

Commission Conclusion

As we explained in the RTG Policy Statement, we intend to give deference to the planning, dispute resolution, and decisionmaking processes of an RTG. With respect to pricing proposals submitted by RTGs, we believe that RTGs may be able to develop solutions to such problems as loop flows through innovative flow-based pricing methodologies. As we stated in the Transmission Pricing Policy Statement, we will afford considerable deference to an RTG.

4. Pacific Northwest

Comments

Commenters in the Pacific Northwest ask the Commission to be flexible in reviewing tariffs that are based on regional practices, and that differ from the final Rule tariff as a result. Public Generating Pool urges the Commission to recognize that the Northwest's transmission system has been developed and is operated to support the region's coordinated power system. That is, it wants all hydro spill to be treated equally with no preference between federal and non-federal power. Also, it asserts that firm available transmission capacity in the Northwest must be worked out by the NWRTA RTG to account for the contingent operation of generation to avoid hydro spill.

Similarly, other commenters note that the Northwest's integrated transmission system was constructed to support a unique regionwide hydroelectric-dependent generating system and that flexibility is needed to accommodate the characteristics of the system.

WA Com argues that imposition of a uniform national tariff would not reflect the region's specific system characteristics or operating practices. It argues that the final Rule could impede rather than promote efficient competition in the Northwest. It believes that the Commission should defer to RTGs for defining and implementing wholesale transmission access terms and conditions at the regional level.

The Washington and Oregon Energy Offices, while supporting the adoption of regional practices, argues that uniform transmission principles should apply for all transmitting entities in the region. They argue that dispatch decisions are complicated by flood control, salmon passage, navigation, irrigation, and other constraints. Puget requests that the Commission give each transmitting utility the flexibility to file tariffs that fit unique or unusual circumstances and allow for regional market differences.

Because the terms and conditions offered by the smaller transmission owners in the Northwest are determined by the terms and conditions offered by Bonneville, Pacific Northwest Coop argues that the terms and conditions for wholesale power transmission, ancillary services, and RINs should be deferred until BPA's 1996 rate case is resolved and until appropriate regional and national systems and protocols are developed.

Commission Conclusion

As we explained with respect to RTGs, we encourage the filing of regional open access transmission tariffs.[FN919] The Final Rule pro forma tariff contains provisions allowing utilities to modify tariff terms to reflect prevailing regional practices. This should permit entities in the Pacific Northwest to address unique circumstances that exist in the Pacific Northwest and to incorporate prevailing regional practices (e.g., treatment of hydropower generation in the priority of dispatch) into their open access transmission tariffs.[FN920] This should also encourage ***21668** other regional solutions, such as the development of regional ISOs, to transmission problems.

In addition, although we will put the Final Rule pro forma tariff (which already allow for certain provisions consistent with regional practices) into effect for all public utilities 60 days after publication of this Rule in the Federal Register, utilities may file regional tariffs or propose deviations in the pro forma tariff based on additional regional needs to be effective at any time thereafter. Such proposals, however, will have to be consistent with the requirements of the Final Rule and be reasonable, generally accepted in the region and consistently adhered to by the transmission provider. Further, we will not permit entities in a region to claim different sets of prevailing regional practices.

5. Power Marketing Agencies

a. Bonneville Power Administration (BPA)

Comments

Washington Water Power explains that for open access transmission to be fully realized in the Pacific Northwest there must be federal legislation to remove the monopoly protections of federally generated power. Until then, Washington Water Power suggests certain mitigating measures that would increase competition in the Pacific Northwest. It also urges the Commission to take BPA's special characteristics into account in issuing the final rule.

Public Power Council encourages the Commission to make broad use of section 211 to mandate transmission access to ensure that BPA continues to provide comparable open access transmission.[FN921]

Public Generating Pool argues that the extent to which BPA's tariffs are allowed to deviate from the rule should be governed by the technical characteristics of the system and not by BPA's status.[FN922]

Direct Service Industries argues that the non-discrimination standard is made applicable to BPA by section 212(i) and that the Commission has the authority to review all BPA rates under the Northwest Power Act (citing Pacific Northwest Electric Power Planning and Conservation Act, section 7(a), 16 U.S.C. 839e(a)). It also argues that functional unbundling is particularly important for BPA because of BPA's market power and relative freedom from regulation. Clark also argues that the Commission should require BPA to meet the comparability standard. It alleges that BPA refuses to provide comparable service. It asserts that the Commission has authority to remedy the problem under the Energy Policy Act amendments to section 212, which Clark states gives the Commission authority over BPA's transmission practices. Clark also notes that BPA is a member of WRTA and, as such, must provide comparable service.

Pacific Northwest Coop argues that many of the issues presented in this rulemaking are currently being contested in the BPA rate case in Docket Nos. WP-96/TR-96 and TC-96. It says that the Commission should defer application of the rule to Pacific Northwest Coop and all of BPA's customers until conclusion of the rate case.

Washington and Oregon Energy Offices asserts that it would be proper for the Commission "to impose similar transmission price structures upon Bonneville under section 211 orders as it will for jurisdictional [public] utilities under sections 205, 206, and the NOPR."

With respect to stranded costs, BPA notes that it may be necessary to tailor a stranded cost policy for BPA that addresses the goals of open access and wholesale stranded cost recovery in a manner consistent with BPA's unique circumstances. BPA asks the Commission to defer consideration of its stranded investment and related cost recovery issues until it makes a rate filing with the Commission.[FN923] It further argues that the rule should not address whether and how BPA stranded costs might be recovered in transmission rates approved by the Commission under authority other than sections 211 and 212. Clark argues that the Commission's stranded cost recovery policy is inapplicable to BPA.

NW Conservation Act Coalition makes the following suggestions: (1) The Commission should grant BPA the authority to levy exit fees on customers who are terminating service and who do not use BPA's transmission system for their new power transaction; (2) any affected person should be allowed to petition the Commission for review of BPA's rates for inadequate or inappropriate mitigation of its stranded benefits; (3) the rule should insist upon a requirement that open access and stranded cost recovery be permitted only if the entities involved can show there will be no lessening of support for public purposes; and (4) the Commission should clarify that the Direct Service Industries customers are retail customers and that they will be subject to recovery of stranded costs and benefits.

Commission Conclusion

BPA is not a public utility under section 201(e) of the FPA and, thus, is not subject to the requirements of this Rule to put the Final Rule pro forma tariff into effect. However, there are three circumstances under which the Commission may review BPA's transmission access and pricing policies. First, BPA could file an open access tariff and accompanying rates for review and confirmation under section 7 of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act)[FN924] and at that time could ask the Commission to find that its tariff meets the Commission's open access policies. Second, BPA is a transmitting utility subject to a request for mandatory transmission services under section 211 of the FPA. Transmission required of BPA under section 211 would have to be consistent with the requirements imposed on BPA under its organic statutes, the Northwest Power Act, and the Federal Columbia River Transmission System Act.[FN925] Third, if BPA receives open access transmission from a public utility, it is subject to the reciprocity provision contained in the utility's Final Rule pro forma tariff. If BPA seeks to comply with the reciprocity provision, it could use the declaratory order procedures we have provided in this rule for non-public utility transmission providers. Finally, we note that BPA has agreed to provide open access as a member of two RTGs approved by this Commission.

With respect to stranded costs, BPA has asked us to clarify that the Stranded Cost Rule does not address whether and how BPA stranded costs might be recovered in transmission rates approved by the Commission under authority other than sections 211 and 212 of the FPA (namely, section 7 of the Northwest Power Act). We clarify that this rule addresses only stranded costs recovered by public utilities under the FPA and transmitting utilities (including BPA) that are subject to mandatory transmission requests under FPA section 211. It does not address stranded cost recovery by BPA under the Northwest Power Act.

***21669 b. Other Power Marketing Agencies**

Comments

SEPA requests that the final rule assure that SEPA can receive network transmission service when necessary. It also indicates that it has 58 customers that receive less than one MW of power, but that the NOPR pro forma point-to-point tariff contains a one MW minimum scheduling requirement. Thus, it requests that the final rule allow some flexibility with respect to this requirement so that it can carry forward its marketing program.

DOE notes that the Western Area and Southwestern Area Power Administrations have pledged to offer transmission services that are comparable to those required of public utilities to the extent not otherwise prohibited by law.

Commission Conclusion

Federal power marketing agencies (PMAs) are not public utilities as defined under section 201(e) of the FPA and, thus, are not required by this rule to file non-discriminatory open access transmission tariffs.[FN926] However, to the extent a PMA receives open access transmission service from a public utility, it is subject to the reciprocity provisions in the utility's pro forma tariff. [FN927] If a PMA seeks to comply with the reciprocity provision, it can file a proposed tariff and seek a declaratory ruling.

With respect to SEPA's concern that the proposed point-to-point tariff has a one MW minimum scheduling requirement, but many of its customers have loads of less than one MW, we clarify that the Final Rule pro forma tariff will allow SEPA to continue to schedule service for these customers. Under SEPA's current transmission arrangements, it is allowed to aggregate loads within a single control area that are less than one MW individually, but jointly are more than one MW, to meet the requirement at an interface. The revised language in the Final Rule tariff permits this practice to continue. We also clarify that SEPA, as a seller of power to multiple purchasers inside several control areas, is eligible to receive network service.

6. Tennessee Valley Authority

Comments

TVA is concerned that the final rule may place TVA at a disadvantage because its opportunities to participate in the electricity market outside the TVA area are so severely limited by statute. It explains that it is restricted from directly participating in the new competitive landscape except through limited power exchange opportunities with a few neighboring systems. It urges the Commission to recognize these circumstances in the final rule. TVA is also concerned that its regional customers may face stranded costs because its ability to mitigate those costs by making replacement sales to new customers is limited.

Commission Conclusion

TVA is not a public utility under section 201(e) of the FPA and, thus, is not required to file a non-discriminatory open access transmission tariff under this rule.[FN928]. However, if TVA receives open access transmission service from a public utility, it is subject to the reciprocity provision in the utility's pro forma tariff. If TVA seeks to comply with reciprocity, it may avail itself of the Commission's reciprocity safe harbor approach, through a declaratory ruling, if it is fearful that a public utility may deny it service simply on a claim that TVA's non-discriminatory open access tariff is not satisfactory.[FN929] The details of this safe harbor procedure are set forth in Section IV.G.4.f.

7. Hydroelectric Power

Comments

Non-Firm Transactions

ID Com believes that the NOPR unfairly discriminates against hydro-based utilities. It argues that utilities that rely heavily on hydropower need to engage in non-firm market transactions that depend on water levels; e.g., during low water years, a utility must have access to the transmission system to make non-firm, off-system purchases. It asserts that the NOPR treats non-firm sales and purchases as subordinate to firm transactions and does not allow the utility to reserve capacity for its critical, but non-firm, transactions. ID Com also asserts that the NOPR would, in effect, strand the utility's investment in the production plant being used to generate power for the non-firm sales.

Idaho complains that the NOPR unfairly allows a customer to buy and reserve firm transmission rights surplus to its needs, but does not permit a utility to do the same. It explains that this problem is particularly acute for hydro utilities and argues that they must be allowed to reserve at tariff rates at least a portion of available transmission capacity for firm and non-firm wholesale transactions. In the alternative, Idaho asserts that the transmission owner should not be required to provide point-to-point service for transmission uses other than from demonstrated firm obligations.

Commission's Licensing Practices

National Hydropower argues that in light of the NOPR the Commission should reexamine the manner in which it exercises its FPA Part I authority with respect to (1) economic feasibility determinations, (2) section 10(a) findings, (3) determinations of section 10(j) recommendations, and (4) section 13. For example, it states that the NOPR suggests that all future electric resource selection decisions should be based exclusively on short-run marginal cost comparisons. Because, it asserts, hydroelectric power provides many public interest benefits not susceptible to precise quantification, the Commission should clarify how non-price factors are to be considered in a post-final rule wholesale electric marketplace.

Commission Conclusion

Non-Firm Transactions

As we explained above with respect to the Pacific Northwest, we will permit entities to incorporate prevailing regional practices (e.g., treatment of hydropower generation in the priority of dispatch) into regional open access transmission tariffs. This should permit entities in a region to resolve concerns over the scheduling of non-firm hydropower. In addition, if a utility and its customers can agree on the scheduling of non-firm hydropower and the disruption of firm transactions, we would permit that resolution to be incorporated into the utility's tariff. Utilities are permitted to consider seasonal variations in hydropower availability in the determination of Available Transmission Capacity to be posted on the OASIS.

Commission's Licensing Practices

The issues raised by National Hydropower with respect to our ***21670** hydroelectric licensing practices are beyond the scope of this rulemaking. Indeed, National Hydropower has already raised its concerns in a petition to the Commission to revise our hydroelectric licensing procedures, filed on July 10, 1995. That is the proper proceeding in which to address our hydroelectric licensing practices.

8. Residential Customers

Comments

Several commenters are concerned that the rule may undermine the financial position of public utilities so that they will not be able to provide many of the programs that benefit low-income residents (e.g., assistance to low-income and elderly consumers, weatherization and energy conservation programs, and payment of taxes that provide many city services).[FN930]

La Raza is concerned that the rule will permit large preferred customers to opt out of the regulated structure, leaving behind a smaller and less affluent base to support the long-term investments made under the previous regulatory environment.

Home Builders is concerned that utilities may compensate for reduced profits under the proposed rule by raising infrastructure charges and hookup fees for new homes, thus reducing new home sales.

State and City Supervised Housing for Equity in Electric Rates states that publicly supervised housing is uniquely qualified to obtain open access electricity from wholesale markets, and that the Commission should adopt policies that bring competitive benefits to residents of such housing.

Commission Conclusion

While some residential consumers may be apprehensive about the changes that this rule may have on the electric industry, we are convinced that the changes we are proposing for wholesale markets will benefit them. As wholesale transmission open access becomes a reality, residential consumers should reap the benefits of more competitive bulk power markets and associated lower costs. This rule does not require retail transmission access for retail customers of any size. Moreover, this rule does not require any changes in programs such as assistance to low-income and elderly consumers and weatherization and energy conservation. As discussed in Section IV.I, those programs are under the jurisdiction of the individual states, and will remain under their jurisdiction. Indeed, this rule contains several safeguards to maintain the ability of states to impose conditions on retail access, such as conditions that help to protect residential customers from becoming the residual payer of stranded costs.

V. Environmental Statement

This section reviews and adopts the final environmental impact statement (FEIS) prepared by the Commission staff in connection with this rule. It identifies the alternatives considered by the agency in reaching its decision; analyzes and considers whether and to what extent the chosen alternative—adoption of this rule—is likely to result in environmental harm; evaluates alternatives and suggestions for mitigating environmental harm from the rule, if any; and states the Commission's decision.

Summary

A. The Environmental Impact Statement

The Commission decided to prepare an environmental impact statement (EIS) evaluating the environmental consequences that could result from adoption of this rule. We did so largely in response to the claims of several commenters, including the Environmental Protection Agency (EPA), who charge that the rule will have significant adverse environmental effects.

Although a number of issues were raised, by far the most prominent concern arises from the theory that competitive market conditions created by the rule will provide an advantage to power suppliers who produce power from coal-fired facilities that are not subject to stringent environmental controls on nitrogen oxides (NO_X) emissions.[FN931] Under this theory, these facilities, located primarily in the Midwest and South, will, as a result of the rule, generate more power and emit more NO_X, which will contribute to ozone formation. The ozone could add to pollution both in those regions and more significantly in the Northeast, to which area such pollutants could be transported. Those who propound this theory argue that it is the responsibility of the Commission, using its authority under the Federal Power Act, to effect environmental controls that will mitigate what they predict will be significant increases in NO_X emissions associated with this rule.

The staff prepared an FEIS based upon computer modeling simulations of power generation patterns and NO_X emissions likely to occur as a result of the rule. Staff used widely accepted models for studying economic conditions in power markets and simulating emissions of NO_X and other pollutants. These models took into account a variety of different assumptions concerning significant factors such as coal and natural gas prices and other competitive conditions. These factors are critical because increased use of coal-fired generation tends to increase NO_X emissions, while increased use of gas-fired generation is environmentally more benign.

The examination in the FEIS of the environmental effects that are likely to result from implementing the rule is based on an analytic framework that was shaped by comments received in the scoping process and on the DEIS. The study was revised to reflect the frozen efficiency reference case assumptions requested by EPA and other commenters. This was done to ensure full disclosure of possible environmental impacts even though the Commission disagrees that use of these assumptions is appropriate.

It has been observed in the context of agency preparation of an environmental study that "(t)he NEPA process involves an almost endless series of judgment calls."[FN932] That is particularly true where, as here, the agency undertakes to examine the impacts of a proposed regulatory program. In designing an effective assessment of the environmental impacts of the rule, the Commission had to make a number of judgments as to the type and the scope of studies necessary to analyze the proposals sufficiently. Commenters also raised many issues related to the design of the study. For example, the Center for Clean Air Policy contends that the Commission should model a range of mitigation policies; the Missouri Department of Natural Resources contends that the impact of the rule on generation may be locally intense and that these effects should have been studied; and other commenters sought to have the Commission examine different database or modeling assumptions.

For these and similar matters we exercised our judgment as to the appropriate manner in which to treat the issue. For example, we determined not to model a range of mitigation ***21671** policies because we did not find that the impacts of the rule require the Commission to adopt or implement a plan of mitigation. It would have been extremely difficult, if not impossible, to examine the many varied local impacts that could be expected across the Nation in response to the Rule. We made judgments as to the appropriate database and modeling assumptions to use—in some cases, those assumptions were shaped or changed by comments we received.

In short, many competing considerations came into play during the design of the complex analysis used to examine the environmental effects of the rule. We exercised our judgment, for example, based on consideration of whether matters are within the scope of the rule, the most appropriate way to study the effects of the proposal, and whether the issues raised were relevant to a consideration of the environmental effects of the rule. The Commission's response to issues raised by commenters is reflected in the response to comments set forth in Appendix J of the FEIS. We conclude that the FEIS reflects the appropriate consideration of these and many similar issues.

B. Major Issues

Some comments on the draft environmental impact statement (DEIS), as well as earlier comments in response to Commission scoping inquiries, raise two major areas of objection to the Commission's analysis. First, commenters claim that in determining what NO_X emission levels would be in the future with the adoption of the rule, the Commission did not compare the emissions levels associated with the rule against the appropriate base case. They argue that the Commission should have analyzed and compared the impacts of the rule to a "no-action" alternative that assumes that the Commission abandons all its open access policies, not just this rule. Some commenters, including EPA, go even further, suggesting that the Commission compare emission levels projected to result from the rule against a "frozen efficiency" case in which other major factors—factors that would increase industry efficiency independent of the Rule—do not occur. Such factors include adoption of pro-competitive state policies and actions by utilities to undertake mutually beneficial voluntary transactions that do not require the use of open access tariffs mandated under this rule. Commenters who advocate either a different "no-action" alternative or the frozen efficiency case expect that studies using those assumptions will show that the rule will cause significantly greater NO_X emissions than shown in the DEIS.[FN933]

Assuming these results, these commenters raise their second major area of concern, which is mitigating the presumed effects of the rule. These arguments vary somewhat but share a common theme: That the Commission has a responsibility, either as a legal or public policy matter, to mitigate what they expect to be the significant environmental impact associated with the rule. They suggest various mitigation schemes, including a FERC-administered NO_X emission allowance program along the lines of the sulfur dioxide (SO_2) program enacted by Congress and administered by the EPA under the Clean Air Act. Other proposals would have the Commission condition the right of a seller to use an open access tariff on certification that the source of the power sold is in compliance with (as yet undetermined) emissions limitations. Another proposal would have the Commission impose a charge on emissions to be paid by utilities to a fund established by the Commission. The added cost to the utilities would work to account for, or "internalize", the external costs of emissions.

Commenters advocating Commission-administered mitigation argue that the mechanisms under current law for regulating NO_X emissions are cumbersome and slow, and that the Commission should not (some argue, may not) go forward with the rule unless it puts in place environmental regulatory mechanisms that prevent further increases in NO_X emissions.

Various legal theories are advanced as a basis for Commission environmental regulation under the Federal Power Act. Some argue that the conditioning authority under the Federal Power Act is sufficient to enable us to fashion comprehensive controls on emissions from utility generators because there is a direct causal nexus between power trading (which we regulate) and generation (which we do not). Others argue that such authority lies in the use of our power to impose requirements on utilities "in the public interest", enhanced by the National Environmental Policy Act. Others argue that, in remedying undue discrimination, we must correct competitive advantages arising from Congressional decisions to exempt certain kinds of generation facilities from some Clean Air Act regulation.

C. Commission Conclusions

After reviewing the comments and the additional studies conducted by staff in response to the comments, the Commission adopts the findings in the FEIS.

First, the findings show that, without the rule, NO_X emissions are expected to decline until at least the year 2000. Thereafter, again without the rule, NO_X emissions are expected to increase steadily through the year 2010 (the end of the FEIS study period). The extent of the decrease and the increase will largely be determined by the relative prices of natural gas and coal, the two main fuels used to generate electric power in most regions.[FN934]

In reaching this conclusion, the FEIS used two "base" cases. In one (the "High-Price-Differential Base Case"), natural gas was assumed to become substantially more expensive compared with coal than it is today. In the other (the "Constant-Price-Differential Base Case"), natural gas was assumed to maintain essentially the same price relative to coal that has existed for the last ten years. The two cases describe the range of emissions due to fuel price uncertainty without the rule and demonstrate the overall trends of decreases until 2000 and increases thereafter.

Second, the FEIS finds that the rule will not in any significant respect affect these overall trends.

The potential impact of the rule was studied initially under two scenarios.[FN935] In one (the "Competition-Favors-Gas Scenario"), the rule is assumed to result in efficiency gains in the electric industry that would tend to favor natural gas as a fuel. In this scenario the effect of the rule is slightly beneficial. Total NO_X emissions are reduced overall by about two percent nationwide from the base cases. In the other (the "Competition-Favors-Coal Scenario"), the rule is assumed to result in efficiency gains in the electric industry that would tend to favor coal as a fuel. In this scenario the effect is again slight, showing approximately a one percent increase in NO_X emissions nationwide from the base cases. In both scenarios, however, the rule does not have an overall effect on NO_X emission trends.

Stated differently, under any case studied, with or without the rule, there will be an overall net decrease in NO_X ***21672** emissions through the year 2000.[FN936] Thereafter, NO_X emissions begin to increase. The rule does not materially affect either the decline prior to 2000 or the increase thereafter.

Based on these findings the Commission concludes that a comprehensive, Commission-imposed mitigation scheme to address the environmental consequences of the rule is not appropriate. If competition favors gas, the effects are beneficial and mitigation is unnecessary. If competitive conditions favor coal through the year 2010, and NO_X emissions increase slightly as a result of the rule, these minor effects would be effectively mitigated as a part of a comprehensive NO_X cap and trading allowance scheme developed by EPA in cooperation with the Ozone Transport Assessment Group (OTAG) and administered by EPA and state environmental regulators under the clearly established authority of the Clean Air Act.

Further, the Commission believes that staff has selected the appropriate "no-action" alternative. An alternative that requires the Commission to reverse all its other open access policies is simply not a "no-action" alternative. To the contrary, it would require decisive action running counter to the direction from the Congress in the Energy Policy Act and the needs of the marketplace and electricity consumers.

However, to ensure that the effects of the rule were analyzed fully, the FEIS did study a reference case based on the "frozen efficiency" case proffered by EPA and the Department of Energy (DOE).[FN937] Although, as described below, we believe this case to be highly unlikely, the results show that, even under this scenario, the impacts of the rule are not great and do not vary significantly from those projected by staff under the other assumptions.

In one case requested by EPA, staff studied a combination of assumptions most likely to show significant increases in emissions associated with the rule; the case included EPA's frozen efficiency scenario, coupled with the "Competition-Favors-Coal" assumptions. Other cases requested by EPA posit dramatic increases in transmission capacity (that we find highly unlikely). Even this combination of assumptions—geared to demonstrate the greatest impact the rule might have on increased NO_X emissions—produced little in the way of environmental consequences associated with the rule. Under these extreme (and unlikely) conditions, there would still be a net decrease in NO_X emissions until at least the year 2000, albeit a smaller decrease than in the base cases. Comparing projections of emissions for the same years, emissions would be higher than the base cases only by two percent in 2000 and three percent in 2005.[FN938] It is only in the year 2010, assuming these improbable scenarios, that NO_X emissions associated with the rule would be higher than the base case by even five percent.[FN939]

Based on these studies, including the EPA reference case, the Commission endorses the staff findings that the rule will affect air quality slightly, if at all, and that the environmental impacts are as likely to be beneficial as negative. This is true even under scenarios contrived to maximize emissions associated with the rule under circumstances that this Commission believes to be highly unlikely.

Importantly, this is also true in the near- to mid-term. Until the year 2010, even the worst case (the frozen efficiency case) produces results very similar to those produced using assumptions the Commission believes to be reasonable. In short, the rule will not produce an "ozone cloud" coming across the Appalachians to threaten the Northeast on the day the rule goes into effect. Assuming that any environmental impacts occur, they are years in the future and may well be beneficial. As a result, calls for Commission mitigation, and in particular for interim mitigation to "fill the gap" until programs under the Clean Air Act can be adopted, are unnecessary and disproportionate to the possible effects of the rule.

We also endorse the staff view that it is neither within our statutory authority nor appropriate as a matter of policy to fashion from the FPA a comprehensive clean air regulatory program to address NO_X emissions. As described below, we believe that the mitigation proposals proffered in comments exceed our statutory authority to regulate rates, terms and conditions of sales of electric energy and transmission of electric energy in interstate commerce. We are, in essence and by law, economic regulators. While we have an obligation under NEPA to take the environmental consequences of our actions into account in fashioning our decision—and we have done so—NEPA grants us no new regulatory powers. While NEPA extends our general obligation to engage in reasoned decisionmaking to include the consideration of possible environmental consequences of our actions, it compels no particular substantive result.

Though our conditioning authority under sections 205 and 206 of the FPA is broad, our actions under it are confined to the subject matter of our jurisdiction. That subject matter excludes the physical aspects of generation and transmission. Our actions must derive from and advance our statutory mandate to protect consumers by establishing utility rates and business practices that are just, reasonable, and not unduly discriminatory or preferential. These authorities, however broad they are with respect to economic matters, are not unbounded; they may not be used to "fill in the gaps" of regulatory programs that, by law, are not our own.

Moreover, even if it were possible to tease from the FPA some implicit authority to regulate NO_X emissions from utility generators, it is not feasible for this Commission to develop and implement such a program. The mitigation schemes presented in comments are filled with unknowns and complexities that are best resolved by those charged with administration of the Nation's environmental laws. In some cases, the mitigation schemes are based on a model of utility transactions that is fundamentally at odds with the purposes of the rule. For example, several proposals would require the Commission to establish whether emissions from certain units or systems contribute to ozone noncompliance elsewhere, perhaps hundreds of miles away. Other proposals would require the Commission to establish baseline standards for emissions; generating units with emissions above that level would be required to adopt mitigation measures. The technical difficulties associated with these proposals are evident on their face. While resolving these issues is necessary to establish an effective NO_X regulatory program, the Commission does not possess the requisite expertise to establish baseline NO_X emission levels and address the difficult technical and policy issues that are presented in regulating NO_X emissions. EPA is the agency with jurisdiction over and experience with such matters.

Although efforts are underway to resolve these issues within the framework of the Clean Air Act, all air regulators agree that much work still needs to be done.

***21673** Other proposals would require the Commission to track generation that is used for wholesale versus retail sales. However, for example, use of holding company corporate structures, as well as emerging market structures, would make it extremely difficult, if not impossible to distinguish between retail and wholesale transactions. In addition, such measures are inconsistent with the goals of the rule (and the Energy Policy Act) to eliminate time-consuming, inefficient transaction-based approvals that impede open access and to promote entry of sellers into bulk power markets on a competitive basis.

Moreover, any such program implemented by this Commission could well undercut the existing regulatory scheme crafted by Congress under the Clean Air Act, as amended. In particular, we are being asked essentially to rework the legislative decisions made by Congress regarding certain coal-fired generators. Those decisions are at the heart of the 1990 Clean Air Act compromise. The only means Congress has made available for addressing these problems under current law are in the Clean Air Act. If these means prove insufficient to address the NO_X problem overall, the case for change must be presented to the Congress.

Although we have concluded that NO_X emissions problems are most effectively addressed by clean air regulations within the framework of the Clean Air Act, we do recognize that the question of NO_X emissions is a very important one. Our FEIS documents that, with or without this rule, NO_X emissions from all sources are expected to increase over time. This will present a significant environmental issue for the Northeast, which is already struggling to reach current NO_X reduction standards, as well as for other regions of the country that are being called on to participate in an inter-regional solution to the NO_X problem. As the EPA rightly recognizes, attempting to frame an appropriate solution with the tools currently available is a tough job. We therefore understand why those concerned would try to enlist this Commission in an effort to solve this problem with regulatory mechanisms other than those set out in the Clean Air Act. We also understand why even the prospect of exacerbating that problem would ignite the kind of controversy reflected in the comments to this rule, and why, in response, those who have gained Congressional exemptions from certain regulations wish not to have those benefits undermined. At the same time, we understand, and have great sympathy with, the many commenters who have suggested that the economic benefits of this rule to consumers should not be suppressed or delayed by this difficult, ongoing debate.

Our FEIS clearly demonstrates that this rule is not the appropriate vehicle for resolving this very important debate. We believe that our study makes a significant contribution nonetheless. We have added significantly to the understanding of the problem and have established a viable, current baseline for assessing future industry trends. This baseline should serve air regulators well in analyzing overall NO_X emissions in the future.[FN940] We have resolved some important questions about the role of open access and have established clearly the influence of energy prices on NO_X emissions in the future.

Our study also supports the view held by many commenters that the appropriate regulatory mechanisms for addressing the NO_X problem overall, including emissions from electric utility generating plants, is a NO_X emissions cap and allowance trading scheme along the lines of that developed by the Congress under the Clean Air Act for SO_2 emissions. As staff suggests, even if there are slight environmental impacts associated with the rule, they are better and more effectively addressed as a part of a comprehensive NO_X regulatory program. While Congress did not enact such a scheme for NO_X, it did, as described below, empower the EPA to establish such a program. The EPA is the only federal agency with clear authority and expertise to address this problem. It should do so.

The FEIS also identifies the importance of OTAG to the development of a fair and effective NO_X regulatory program. OTAG, which includes representatives from all affected states, is currently at work developing the analytic basis needed for a regional consensus solution to the NO_X problem. OTAG is also evaluating possible solutions, including an allowance trading scheme. We believe that OTAG's efforts are to be applauded, and we encourage the EPA and all interested parties to work with OTAG to address this issue of national concern.

Discussion

A. Compliance With NEPA Requirements

1. Background

The Commission issued a NOPR in this proceeding on March 29, 1995. In doing so, we concluded that promulgating the proposed Rule would not represent a major federal action having a significant adverse impact on the human environment and that the proposed Rule fell within the categorical exemption provided in the Commission's regulations for electric rate filings submitted by public utilities under sections 205 and 206 of the FPA.[FN941] Subsequently, the Commission determined that, despite the availability of the categorical exclusion, it would nonetheless prepare an environmental analysis. On July 12, 1995, the Commission directed staff to prepare an EIS to assess the environmental impacts of the proposed Rule. That notice requested comments on environmental issues and scheduled a scoping meeting for September 8, 1995.[FN942]

A Notice of Availability of the DEIS was published in the Federal Register on November 27, 1995.[FN943] The DEIS evaluated several potential alternatives and mitigation measures as summarized below.

A Notice of Availability of the FEIS was published in the Federal Register on April 19, 1996.[FN944]

2. General Requirements

Section 102 of NEPA, 42 U.S.C. 4332, requires that federal agencies prepare an EIS on proposals for major federal actions significantly affecting the quality of the human environment. The objective is to build into the agency decisionmaking process careful consideration of environmental aspects of proposed actions, including the evaluation of reasonable alternatives. Although we believe a categorical exclusion to be available,[FN945] the Commission has performed this EIS to ensure that this Rule is promulgated with the benefit of careful consideration of its environmental aspects.

3. Alternatives

The consideration an agency must give in an EIS to alternatives to its proposed action is bounded by a number of factors, including notions of feasibility, whether basic changes would ***21674** be required to the statutes and policies of other agencies, and the extent to which the proposal would result in significant impacts. The United States Supreme Court (Supreme Court or Court) stated what is required in an EIS with regard to alternatives in Vermont Yankee Nuclear Power Corp. v. NRDC, 435 U.S. 519, 551 (1978): "(A)s should be obvious even upon a moment's reflection, the term 'alternatives' is not self-defining. To make an impact statement something more than an exercise in frivolous boilerplate the concept of alternatives must be bounded by some notion of feasibility." [FN946] In this regard, the Supreme Court quoted Natural Resources Defense Council v. Morton, 458 F.2d 827, 837-38 (D.C.Cir. 1972), with approval as follows:

There is reason for concluding that NEPA was not meant to require detailed discussion of the environmental effects of "alternatives" put forward in comments when those effects cannot be readily ascertained and the alternatives are deemed only remote and speculative possibilities, in view of basic changes required in statutes and policies of other agencies—making them available, if at all, only after protracted debate and litigation not meaningfully compatible with the time-frame of the needs to which the underlying proposal is addressed.

The Supreme Court went on to discuss the concept of "feasibility", stating that:

Common sense also teaches us that the "detailed statement of alternatives" cannot be found wanting simply because the agency failed to include every alternative device and thought conceivable by the mind of man. Time and resources are simply too

limited to hold that an impact statement fails because the agency failed to ferret out every possible alternative, regardless of how uncommon or unknown that alternative may have been at the time the project was approved.[FN947]
Thus, an EIS must discuss the alternatives that are feasible and briefly discuss the reasons others were eliminated. There is no minimum number of alternatives that must be discussed.[FN948] An agency's consideration of alternatives is adequate if it considers an appropriate range of alternatives—it does not have to consider every available alternative.[FN949]

The range of alternatives that must be considered in the EIS need not extend beyond those reasonably related to the purposes of the project.[FN950] An agency is entitled to identify some parameters and criteria related to the proposal for generating alternatives to which it would devote serious consideration. Without such criteria, an agency could generate countless alternatives.[FN951] Alternatives that are unlikely to be implemented need not be considered, nor must an agency consider alternatives that are infeasible, ineffective, or inconsistent with basic policy objectives.[FN952] In this sense, central to evaluating practicable alternatives is the determination of a project's purpose.[FN953]

Furthermore, the range of alternatives that reasonably must be considered decreases as the environmental impact of a project becomes less and less substantial. If a proposal would have minimal environmental effect, the range of alternatives that must be considered is narrow. It would be an anomaly to require that an agency search for more environmentally sound alternatives to a project that it has determined will have no significant environmental effects.[FN954] Moreover, feasible alternatives may be rejected if they present unique problems or cause extraordinary costs and community disruption.[FN955]

As applied to the instant case, NEPA does not require the consideration of alternatives that are remote and speculative possibilities because they would require basic changes to statutes and policies. Therefore, alternatives that would require the Commission to ignore open access policies enacted by Congress in the Energy Policy Act and to assume such policies would not be pursued by the states are not feasible and need not be considered. Likewise, the Commission need not consider alternatives that are ineffective or inconsistent with basic policy objectives, or that would cause extraordinary costs and community disruption. Finally, because the rule would have minimal environmental effect, the range of alternatives that must be considered is narrow. We conclude that staff has examined the appropriate alternatives in the FEIS and correctly determined that promulgation of the rule represents the most appropriate action.

Certain commenters have argued that the alternative that calls for the Commission to abandon the policy of promoting transmission access is more appropriate for the no-action alternative than the no-action alternative selected by the staff.[FN956] We disagree. As discussed below, that contention is more properly an argument about the appropriate baseline to use in the FEIS. That debate has been resolved by the consideration of a reference case that includes a baseline which bounds the effects that those commenters seek to have analyzed.

4. Mitigation
To fulfill the requirements of NEPA with regard to mitigation, an agency must identify and evaluate the adverse environmental effects of the proposed action, in this case the rule. Having identified and evaluated adverse environmental effects, the agency is not constrained from then deciding that other values outweigh the environmental costs of the proposal.

The leading case interpreting this requirement is Robertson v. Methow Valley Citizens Council, 490 U.S. 332 (1989)(Methow Valley). There, the Court explained that:

Although these procedures (preparation and circulation of an EIS) are almost certain to affect the agency's substantive decision, it is now well settled that NEPA itself does not mandate particular results, but simply prescribes the necessary process. If the adverse environmental effects of the proposed action are adequately identified and evaluated, the agency is not constrained by NEPA from deciding that other values outweigh the environmental costs * * *. Other statutes may impose substantive environmental obligations on federal agencies, but NEPA merely prohibits uninformed—rather than unwise—agency action. [FN957]

The Court held that "(t)o be sure, one important ingredient of an EIS is the discussion of steps that can be taken to mitigate adverse environmental consequences."[FN958] This is so because:

Implicit in NEPA's demand that an agency prepare a detailed statement on "any adverse environmental effects which cannot be avoided should the proposal be implemented, 42 U.S.C. 4332(C)(ii), is an understanding that the EIS will discuss the extent to which adverse effects can be avoided. More generally, omission of a reasonably complete discussion of possible mitigation measures would undermine the "action-forcing" function of NEPA. Without such a discussion, neither the agency nor other interested groups and individuals can properly evaluate the severity of the adverse effects * * *.[FN959]

The Court acknowledged that:

There is a fundamental distinction, however, between a requirement that mitigation be ***21675** discussed in sufficient detail to ensure that environmental consequences have been fairly evaluated, on the one hand, and a substantive requirement that a complete mitigation plan be actually formulated and adopted, on the other * * *. Even more significantly, it would be inconsistent with NEPA's reliance on procedural mechanisms—as opposed to substantive, result-based standards—to demand the presence of a fully developed plan that will mitigate environmental harm before an agency can act.[FN960] .
The Court again stressed that "(b)ecause NEPA imposes no substantive requirement that mitigation measures actually be taken, it should not be read to require agencies to obtain an assurance that third parties will implement particular measures."[FN961] Thus, the Court held that mitigation, including mitigation that other governmental bodies have jurisdiction to implement, must be discussed in sufficient detail to ensure that environmental consequences of a proposed action have been fairly evaluated. However, a complete mitigation plan need not be actually formulated or adopted.

The suggestion by various commenters that the Commission is required to adopt and implement a plan to mitigate the impacts of the rule is without legal or factual basis. Even if the effects of the rule were greater than the FEIS shows them to be, Methow Valley clearly establishes that, regardless of the impacts of the proposed action, the Commission is required only to understand the impacts of its actions. This compels us to consider and discuss mitigation; it does not require us to adopt and implement mitigation. This FEIS thoroughly examines mitigation of possible adverse environmental effects and concludes that sufficient mechanisms exist to address the impacts of the rule, if any.

5. Role of EPA
Section 309 of the Clean Air Act, 42 U.S.C. 7609, authorizes EPA to review and comment on environmental impact statements prepared by federal agencies. If the EPA Administrator determines that a proposed regulation is unsatisfactory from, among other things, the standpoint of environmental quality, she may refer the matter to the Council on Environmental Quality (CEQ). [FN962]

In this case, EPA has commented extensively on the DEIS. It sought changes to the staff's analysis, primarily to include the use of the frozen efficiency assumptions. The staff has fully complied with EPA's study requests even though it regards such assumptions as implausible, contrary to the Energy Policy Act and Commission policy, and at odds with industry trends and practical considerations affecting the industry.[FN963]

Although EPA may disagree with the environmental acceptability of an agency's proposal, the agency is charged with making the ultimate determination whether to implement a proposal; in making that decision, the agency is free to reject advice offered through the comment and referral process.[FN964] Objections on the part of EPA may give rise to a heightened obligation of the agency to explain clearly and in detail its reasons for proceeding in the face of those objections. This the Commission has done. It has thoroughly examined the impact of the assumptions advanced by EPA; that analysis is detailed in Chapter 6 of the FEIS.[FN965]

In summary, NEPA prescribes a process and not a result. What is critical is that environmental impacts of a proposed action be adequately identified and evaluated—an important component of this process is understanding the possible mitigation measures that are involved, including measures which may be beyond the jurisdiction of an agency to implement. This requirement does not translate, however, into a requirement that an EIS adopt a mitigation plan, particularly where, as here, the impacts of the rule are small and may be either positive or negative.

B. Analysis of Alternatives

The FEIS evaluated three alternatives to the rule including: (1) A no-action alternative which assumes that the rule is not adopted, but that existing statutory and regulatory policies remain in place; (2) a Commission decision to reverse existing policies and halt implementation of mandatory open access; and (3) a Commission decision to aggressively develop competitive power markets by mandating corporate reorganization or divestiture.

1. The No-Action Alternative

The principal alternative to the proposed action is for the Commission not to adopt the rule, but to continue its existing open access and stranded cost policies. In recent years, the Commission has required public utilities that merge or seek to acquire jurisdictional transmission facilities under section 203 of the FPA to file open access transmission tariffs. The Commission also has required public utilities to file open access transmission tariffs to mitigate market power and to ensure non-discrimination if they or their affiliates wish to sell power at market-based rates. In addition, the Commission processes case-by-case requests made by potential transmission users under section 211 of the Energy Policy Act for transmission service, and has allowed utilities to include stranded cost provisions in their open access transmission tariffs on a case-by-case basis.[FN966]

Actions taken pursuant to section 211, and pursuant to sections 203 and 205 in merger and market-based rate cases respectively, represent a case-by-case approach to establishing open access. By contrast, the rule would, in a single generic proceeding, require each jurisdictional public utility to file open access tariffs at the same time. The consumer benefits from the rule are expected to be $3.8 to $5.4 billion per year.[FN967]

Absent action on the rule, the Commission would continue on a case-by-case basis to require public utilities to file open access tariffs and provide case-specific service as necessary or appropriate. Sections 205 and 206 charge the Commission with ensuring that voluntary transmission tariffs are not unduly discriminatory. If the rule were not adopted, the Commission would continue to require that voluntary tariffs be upgraded to offer non-discriminatory open access transmission services pursuant to the Commission's current standards. The result of continuing the Commission's policies without the rule is that the Commission would effectuate a more open transmission grid than is present today, but in a patchwork manner and at a slower pace. Over some extended time period, many, but not necessarily ***21676** all, utilities would become subject to open access requirements.

The case-by-case approach to achieving open access now in use is slower and more costly, and thereby less desirable, than the generic approach set forth in the rule. Given the rapid changes facing the industry, and the opportunity for great consumer savings, the no-action alternative is not a reasonable alternative to the rule.

2. Abandon the Policy of Promoting Transmission Access

A second alternative is for the Commission to abandon its current policy and take no action whatsoever to foster transmission access. Under this alternative, the Commission would no longer require open access transmission as a condition of mergers and asset acquisitions under section 203 or requests for market-based pricing under section 205, and would no longer grant applications filed pursuant to section 211. Offers of transmission would become strictly voluntary.

This alternative is inconsistent with Congress' general intent in the Energy Policy Act to foster wholesale competition, and also with its specific intent in expanding section 211 to permit the Commission to require a transmission-owning utility to make its transmission system available to eligible users if to do so is in the public interest. This alternative is also inconsistent with the Commission's obligations under sections 205 and 206 to ensure that public utilities do not unduly discriminate in providing jurisdictional services. It is, therefore, not a reasonable alternative to the rule.

3. Corporate Reorganization/Divestiture Alternative

Under this alternative, the Commission would require public utilities either to divest control of their transmission assets or to reorganize their corporate structures to perform their transmission functions through a separate subsidiary, thereby segregating transmission from the rest of the utilities' operations. However, corporate reorganization or divestiture would have no effect on the operation of power plants, which are assumed to be dispatched on the basis of economic efficiencies. Thus, this alternative would lead to the same environmental impacts as the rule. That is, the environmental effects would be no different from those studied in the FEIS.

C. The Scope of the FEIS

The FEIS examines the environmental impacts that could result from implementing this rule. This analysis is undertaken against the background of the existing electric industry. The electric industry currently produces environmental impacts, and those impacts are certain to change over time as the industry responds to factors as varied as changes in demand for electricity, the price of fuels, changes in regulatory programs, technological developments, and changes in market structure.

The FEIS does not examine the environmental impact of electric generation that is required to meet generators' existing service requirements. Nor does it examine the environmental effects of the inter-utility power exchanges that have occurred in the industry for as long as utilities have been interconnected. Rather, the FEIS examines impacts of potential increases in generation and changes in patterns of generation that might result from implementation of the rule.

In creating an analytical construct to examine the impacts of the rule, the staff developed a set of cases that defined the framework for running the computer models utilized to examine the changes in types of power plants constructed in the future and changes in operating patterns of existing power plants, including changes in fuel mix.

First, staff characterized how electric power markets might evolve absent adoption and implementation of the rule by establishing baselines (i.e., base cases) to project the future impacts of the industry.[FN968] The relative prices of coal and natural gas are critical in establishing what is likely to happen in the future. Accordingly, a range of prices was developed to project the impacts of these factors. In the first baseline, the Constant-Price-Differential Base Case, coal and natural gas prices are assumed to maintain the same relative position they have maintained over the past ten years. In the second baseline, the High-Price-Differential Base Case, natural gas is assumed to become substantially more expensive compared with coal than it has been over the past 10 years. In all other respects, the assumptions underlying the two base cases are the same.

Because the purpose of the base cases is to describe the impacts of the electric industry if the Commission takes no action over and beyond continued implementation of existing policies, the baselines assume that the Commission continues the open access and stranded cost policies it has instituted in recent years.

Some commenters have challenged this aspect of the baselines used in the study. The gist of their argument is that the environmental impacts of these programs have not been evaluated and that the baselines therefore improperly take credit for impacts that have not yet occurred, thus understating the projected impacts of the rule. In general, these commenters argue that the second alternative considered by the staff represents the “true” no-action alternative.

At bottom, this debate is not about what constitutes the appropriate no-action alternative. Rather, it is a debate about what aspects of the electric industry should be taken into account when determining future environmental impacts of the industry against which to measure the impacts of the rule. The commenters urge the Commission to consider varying baselines, but in general they oppose inclusion in the base cases of the Commission's ongoing open access and stranded cost programs.

Some commenters not only urge that the Commission not take into account continued implementation of its open access and stranded cost programs, but that it go much farther and establish baselines (against which to examine the impacts of the rule) that do not reflect the impacts of a great many changes that are already taking place in the electric industry. This proposal would establish a baseline that does not take into account: (1) Current Commission transmission policy; (2) programs that states and industry players have adopted to improve industry efficiency; and (3) mutually beneficial transactions that electric companies enter into on a regular basis.

The use of these assumptions would fly in the face of long-standing industry trends which move in precisely the opposite direction. Utilities are reducing reserve margins, improving plant availabilities, and reducing barriers to transmission even without Commission action.[FN969] Many states are aggressively pursuing plant efficiency policies.[FN970] These trends are long-standing and are not attributable to the rule, or even to a broader Commission program of open access. These trends, projected into the future, form the basis for the conditions reflected in the FEIS base cases. These trends are fundamentally at odds with the assumptions some commenters wish the Commission to use to establish baselines.

***21677** We conclude that the approach used by staff to develop the baselines used in the FEIS is appropriate. Abandoning current open access policies is unrealistic, contrary to Congressional intent, and at odds with pro-competition policies that are at the heart of the Commission's current regulatory mission. The selection of the appropriate methodology to establish the baselines used in the FEIS is clearly within the Commission's discretion and expertise.[FN971]

What the commenters challenging this assumption desire is additional study of the impacts of the rule. Specifically, they wish to test the rule against a different set of assumptions for the acknowledged purpose of attributing greater adverse environmental consequences to the rule. The regulations of the Council on Environmental Quality no longer contain a requirement to conduct a conjectural "worst-case analysis."[FN972] NEPA requires an agency to adequately identify and evaluate the adverse environmental effects of a proposed action.[FN973] It does not require the agency to ignore the world as it exists.

Nonetheless, to respond to concerns about the baselines used in the DEIS with respect to key atmospheric emissions, the staff conducted sensitivity analyses to examine the outer boundaries of a range of cases requested by some commenters. This range of cases is called the "frozen efficiency" case. In essence, the frozen efficiency cases assume that no further open access of any kind occurs during the study period and that efficiency in the industry (for instance, power plant availability) remains frozen through the same period. The assumption that there is substantially more inter-regional transmission capacity than posited in the original analysis is separately examined in the base and rule cases.[FN974]

We must reiterate that the frozen efficiency case is far more restrictive in its assumptions than a true no-action case in which the Commission simply stops all efforts to promote open access. A true no-action case would closely resemble the FEIS base cases because much of the efficiency gain in that base case would occur even with no move toward open access.

As detailed in Chapter 6 of the FEIS, and as discussed below, even the frozen efficiency case demonstrates results that are essentially the same as those demonstrated by the base cases used by the staff. In the frozen efficiency worst case, when coal prices become considerably more attractive compared to gas prices, national NO_X emissions would be lower than in the base cases used by staff by only one percent (in 2000) to four percent (in 2010). If coal and natural gas prices remain at today's relative levels, the effects would be smaller—zero percent in 2000 to two percent lower in 2010. National CO_2 emissions would be between zero and two percent lower than in the base cases used by the staff over the same time frame.

D. Economic and Environmental Impacts of the Rule

The FEIS reports a quantitative estimate of approximately $3.8 billion to $5.4 billion in benefits per year of cost savings expected from competition under the rule. The FEIS also considers other, non-quantifiable benefits that can be expected from implementing the rule. These benefits include better use of existing assets and institutions, new market mechanisms, technical innovation, and less rate distortion. Further, the FEIS demonstrates to our satisfaction that the rule is likely to have little or no adverse environmental impact and that any impacts are as likely to be beneficial as harmful.

The issue most frequently raised by commenters involves air quality impacts, particularly the possible transport of NO_X emissions from upwind areas to airsheds in the Northeast and the resulting impacts on ozone non-attainment areas.

With regard to NO_X, the FEIS demonstrates that, as a result of clean air regulatory programs, NO_X emissions nationwide, with or without the rule, will decline through the year 2000, but begin to climb thereafter.[FN975] This basic trend remains the same in all cases examined in the FEIS. This is because the level of NO_X emissions in any given year depends primarily on one key uncertainty that is not related in any way to the rule—the relative price of natural gas and coal.[FN976] Lower prices for natural gas, relative to coal, lead to lower levels of NO_X emissions.

The FEIS also demonstrates that increases in access to transmission and efficiencies in electric power markets associated with the rule do not alter the expected trend of NO_X emissions, regardless of the relative price of natural gas and coal. Increased transmission access and industry efficiency facilitated by the rule may either decrease total emissions somewhat or increase them somewhat, depending on whether competitive conditions in the electric industry favor natural gas or coal. When competitive conditions favor natural gas, the effect of the rule is beneficial, reducing emissions somewhat. When competitive conditions favor coal, emissions increase by a small amount. Nevertheless, the overall trend of expected NO_X emissions retains its general shape.

In assessing the projected impacts of the electric industry absent adoption of the rule (i.e., the base cases studied in the FEIS), the most important factor affecting changes in national NO_X emissions is the relative competitive position of coal and natural gas. The most important factor affecting the relative competitive positions of coal and natural gas is price.

National NO_X emissions from the electric industry were 5,844 thousand tons in 1993, the last year for which complete data is available. If relative gas ***21678** and coal prices remain the same, for example, we project that national NO_X emissions will be 5,579 thousand tons in 2005 without adoption of the rule. If gas prices rise relative to coal prices, we project that NO_X emissions in 2005 will be 6,053 thousand tons without adoption of the rule. Stated another way, favorable coal prices are projected to result in NO_X emissions that are about three percent higher in 2000 to 10 percent higher in 2010 over the base case where gas is the favored fuel.

The effect of adopting the rule could be to raise or lower national emissions slightly compared to the effects projected in the base cases. Nationally, in 2005, we project that the Competition-Favors-Coal Scenario (with rising relative gas prices) would add one percent to NO_X emissions above the base case that favors coal. The Competition-Favors-Gas Scenario (with constant relative fuel prices) would lower emissions by two percent compared with the base case that favors gas.

Regional effects are generally similar. In 2005, in the East North Central region (a source of potential increased NO_X emissions that might affect the Northeast), the base cases project small increases in industry emissions (two percent). In that region in 2005, the rule may add as much as one percent to NO_X emissions compared to the relevant base case (the Competition-Favors-Coal Scenario) or reduce emissions compared to the relevant base case by as much as three percent (the Competition-Favors-Gas Scenario).

The EIS uses the UAM-V model to track the effects of projected NO_X emissions on downstream ozone levels during a severe weather period. This detailed air quality modeling shows no real difference in the Northeast between the base case favoring coal (the High-Price-Differential Base Case) and the Competition-Favors-Coal Scenario. Detailed local analysis shows slightly lower ozone concentrations in some locations and slightly higher concentrations in others. None of the differences adds to non-attainment levels projected in the relevant base case, and all fall within the noise levels of the model. That is, they are smaller than the uncertainties in the science underlying the model.

As discussed above, the Commission believes that the base cases used by staff in its analysis are the most realistic and, therefore, the most appropriate cases to consider the potential environmental impacts of the rule. However, as requested by the EPA, DOE, and certain other commenters, sensitivity analyses were conducted to examine the impacts on the results of the analysis if key assumptions are changed as requested by commenters. Presumably, comparing the projected impacts of the rule to the requested "frozen efficiency" case provides a measure of the greatest impacts that could possibly (albeit unrealistically) be expected from implementing the rule.[FN977]

As the FEIS discusses, even comparing projected NO_X emissions under the rule to the highly implausible frozen efficiency case, impacts attributable to the Rule are projected to be modest or non-existent. This holds true even when large (up to 40 percent) increases in transmission capacity are assumed to occur under the rule.[FN978] Moreover, adding coal-favoring assumptions—which would presumably increase emissions—about future competitive conditions in the electric industry to the implausible frozen efficiency assumptions, NO_X emissions are projected to increase very modestly until the year 2010 (by only two percent in 2000 and three percent in 2005). Even using this highly unlikely alternative to the rule, the analysis projects a net environmental benefit (although a very small one) if gas prices stay constant compared to coal prices.

Concern also has been expressed with regard to the need to mitigate CO_2, mercury, and fine particulate emissions, and with the impact of the rule on visibility. As with NO_X, the FEIS demonstrates that the rule is as likely to improve such emissions and visibility as it is to exacerbate them. In any event, the impact is expected to be small.

In sum, the Commission adopts the FEIS findings that:

- The relative price of coal and natural gas has a larger effect on NO_X emissions than any impacts from the proposed rule. Without the proposed rule, different fuel price assumptions are projected to lead to a 7 percent difference between the two base cases in nationwide NO_X emissions in 2005, with some regions affected more than others.

- The rule is projected to have only slight impacts on NO_X emissions, and the impacts are as likely to be beneficial as harmful. In 2005, if competitive conditions in the electric industry (for instance, heat rates) favor natural gas, the proposed rule is projected to decrease baseline NO_X emissions by 2 percent nationwide. If competitive conditions favor coal, the rule is projected to raise baseline NO_X emissions by 1 percent. Regional effects in both cases are generally similar. In short, any negative impacts that the rule might cause are a small fraction of the uncertainty inherent in fuel price projections.

- Even a substantial increase in transmission capacity (up to 40 percent on every transmission line in the country) would change emission estimates by very small amounts in all cases. In many cases, the changes would represent net environmental benefits.

- Even comparing projected emissions under the proposed rule to the highly implausible frozen efficiency case, impacts attributable to the rule are projected to be modest or non-existent. The staff believes this is an unreasonable comparison because the frozen efficiency assumptions ignore industry trends that the Commission is generally powerless to stop. In effect, they assume that the alternative to the proposed rule is (1) for the Commission to reverse current transmission policy, an action that is inconsistent with Congressional policies under EPAct, (2) for states to cease adopting programs to improve industry efficiency, and (3) for electric companies to cease entering mutually beneficial transactions. Even after adding coal-favoring assumptions about future competitive conditions in the electric industry to the implausible frozen efficiency assumptions, NO_X emissions are projected to increase only very modestly until 2010 (by only 2 percent in 2000 and 3 percent in 2005). Even using this highly unlikely alternative to the proposed rule, the analysis projects a net environmental benefit (although a very small one) if gas prices stay constant compared to coal prices. EPA indicates that it considers the lower gas price assumption to be "the more likely of the base cases" (DEIS comments, p. 35).[FN979]

E. Mitigation Analysis

An agency is required to consider mitigation if the proposed action will result in adverse environmental impacts.[FN980] The insistence of commenters that the Commission adopt and implement mitigation measures is based on significantly overstated assumptions regarding the contribution of the rule to existing environmental problems. The analysis presented in the FEIS establishes that these assumptions about the impact of the Rule are wrong. As stated in the FEIS,

The sensitivity analyses (i.e., the frozen efficiency case requested by EPA, DOE and other commenters) do not support the argument that the proposed rule is likely to lead to large immediate impacts that require ***21679** immediate mitigation. In fact, using the more reasonable EIS base cases, it is clear that the proposed rule is at least as likely, if not more likely, to benefit the environment as it is to have adverse environmental impacts. As a result, we believe it is not a responsible course of action to undertake efforts to mitigate speculative adverse environmental consequences that may well not materialize; such action could well have the opposite effect and delay the clear benefits the proposed rule will produce in order to address small, highly uncertain environmental impacts.[FN981]

Even if the rule were to result in adverse environmental impacts as a result of competitive conditions that favor the future use of coal, such impacts are not likely to occur until about the end of the time period examined in the FEIS. EPA in its comments on the DEIS stressed, based on views it formed prior to knowing the results of the frozen efficiency case, that the Commission should develop interim mitigation until EPA can implement a program of controls. EPA stated in its comments that it has authority to address "some" of the impacts it believed would result from the rule, but stated that it would take it considerable time to do so—up to 10 years. The results of the unrealistic worst case analysis demonstrate that adverse effects would not be expected to occur for approximately 10 years in any event. Thus, interim mitigation is not required; EPA will have sufficient time to develop under the Clean Air Act whatever mitigation plan it may deem necessary.

Although the staff concluded that mitigation was unnecessary given the results of its analysis, given the importance of this issue, it nonetheless examined in considerable detail measures, including those proposed by commenters, that could be taken to mitigate adverse environmental consequences of the rule if they were to occur. The FEIS focuses on NO_X emissions in particular given the importance assigned to this issue by commenters.

1. Mitigation Measures Under the Clean Air Act

As discussed in greater detail in the FEIS, the existence for many years of a significant ozone non-attainment problem in parts of the U.S. has led to the development of mechanisms to address this issue. In particular, Congress has established requirements in the Clean Air Act for regulating NO_X emissions. These requirements establish specific NO_X emission levels for certain types of boilers. As discussed below, the Commission is not authorized to alter those requirements as requested by certain commenters.

In the 1990 Amendments to the Clean Air Act, Congress enacted the Acid Rain Program to reduce annual SO_2 and NO_X emissions. For SO_2, Congress established a cap and trade program that uses a market-based allowance system to reduce SO_2 emissions from utilities by approximately 50 percent. The allowance system caps utility emissions at 8.9 million tons a year by 2000. A pool of 8.9 million allowances was then created, each representing the right to emit one ton of SO_2 pollution in a specified calendar year. The allowances can be used to permit current emissions, sold, or held in reserve.

As a result of uncertainty in the understanding of ozone formation and transport, Congress acted less aggressively in regulating NO_X emissions. It chose to limit NO_X emissions from utilities by means of allowable emission limits and to require further study of ozone precursors, leaving room for the EPA to abate NO_X requirements where scientifically justified. Accordingly, in section 407 of the Clean Air Act, 42 U.S.C. 7651f, Congress established a NO_X reduction program which provides that EPA shall by regulation establish annual allowable emissions limitations for NO_X for specified types of utility boilers (Group 1 boilers). Section 407 also provides that, by not later than January 1, 1997, the Administrator shall establish allowable emission limitations for NO_X on a lb/MMBtu, annual average basis for specified other types of utility boilers (Group 2 boilers).

On April 13, 1995, EPA promulgated a Rule setting emission limitations on Group 1 boilers that combust coal as a primary fuel. EPA reports that the April 13, 1995 regulation "is expected, by the year 2000, to nationally reduce NO_X emissions by an estimated 1.54 million tons per year."[FN982]

On January 19, 1996, EPA published a proposed rule to implement the second phase of the Acid Rain Program. This rule proposes to establish NO_X emission limitations for Group 2 boilers and to revise NO_X emission limitations for Group 1 boilers to impose tougher standards EPA states that "[t]he proposal would, by the year 2000, achieve an additional reduction of 820,000 tons of NO_X annually."[FN983]

In addition, Congress determined to deal with the issue of the interstate transport of ozone by authorizing the formation of transport commissions. The Clean Air Act authorizes EPA to establish transport regions that are charged with assessing the degree of interstate transport of pollutants, assessing mitigation strategies, and recommending revisions to State Implementation Plans to correct the problem. The Clean Air Act specifically establishes an ozone transport region (OTR) for the Northeast. The jurisdictions that comprise the OTR have developed a coordinated approach to this problem that includes adopting a regional cap on NO_X emissions.

Although the OTR process is achieving its purpose, a broader program is clearly appropriate to address the overall problem. As a consequence, the Ozone Transport Assessment Group (OTAG) has been formed which encompasses the OTR and upwind states that contribute to non-attainment. OTAG is performing extensive photochemical grid modeling of the eastern U.S. to determine ozone transport problems and to evaluate the efficiency of various control strategies. OTAG is considering recommending a cap and trade system for NO_X emissions from all sources in a 37-state area comprising the Northeast OTR and upwind states. If the cap and trading system becomes effective it therefore should fully mitigate NO_X emission increases, if any, attributable to open access transmission within the 37-state area. A cap and trade program is also likely to mitigate CO_2 and mercury emissions.[FN984] Any incremental increases in NO_X, mercury, or CO_2 emissions that may result from the rule can and should be addressed within this existing framework.

All of these factors lead us to agree with the staff's conclusion in the FEIS that a cap and trading system such as that under consideration in the OTAG process is the preferred approach to the overall NO_X emissions problem, including emissions associated with the rule, if any. This approach brings together EPA and the concerned states in a program that utilizes existing regulatory authority under the Clean Air Act.

The OTAG process brings to the table the parties that must participate in making the difficult decisions necessary to fully resolve this problem. OTAG possesses the technical resources and expertise to address the difficult scientific and technical issues that must be resolved to remedy this problem. A cap and trading system will require the ***21680** development of emission baselines for a great many entities; development of such baselines is certain to require extensive modeling and many difficult compromises. OTAG and others have been working towards this end for a long time. A more limited approach—one undertaken by this Commission or aimed at the limited (and only potential) impacts of the rule—cannot render a satisfactory solution. A program designed to deal with the slight impacts associated with the rule will not contribute significantly to the overall solution and could, indeed, impede it if the Commission took actions that prove inconsistent with solutions developed by OTAG or if debate over Commission-sponsored mitigation were to continue to distract interested parties from the preferred route of developing a consensus solution within the framework of the Clean Air Act. We respect the expertise and the goals of the OTAG process and do not believe we can or should substitute for them in addressing this long-term national problem.

2. Mitigation Measures Proposed by Commenters

The FEIS also analyzes NO_X mitigation measures proposed by commenters. These include voluntary measures pursuant to which the Commission would support utility efforts to mitigate pollution and proposals under which the Commission would mandate mitigation. Commenters suggest a variety of Commission actions including using its conditioning authority to require utilities to consider environmental impacts;[FN985] sanctioning imputed charges in rates to reflect incurred environmental externalities; and designing specific, transaction-oriented mechanisms designed to address the increment of emissions attributable to new wholesale transactions resulting from the rule.[FN986] The FEIS discusses five proposals in some detail: Those presented by the Center for Clean Air Policy (CCAP), the EPA, Joint Commenters, the Project for Sustainable FERC Energy Policy (Sustainable FERC), and the DOE.[FN987] Of these, the FEIS recommends the proposal put forward by DOE:

Staff concurs (with the DOE analysis) that the best solution to the problem of NO_X transport and ozone non-attainment lies in exercise of statutory authority under the Clean Air Act by EPA and the states. Absent Congressional action, no resolution of the difficult political and technical issues will represent a lasting solution of this problem except one that comes from a collaborative process such as OTAG.[FN988]

As the FEIS explains in great detail, each of the other recommendations suffers from serious shortcomings. In one form or another, they would require the Commission to implement technically complex emissions control regimes outside of the Commission's expertise. Some would require that we duplicate existing monitoring systems. Others would require that we implement provisions that would, in effect, defeat the very purpose of the rule.[FN989] Indeed, these recommendations would have the Commission embark upon an extensive environmental regulatory regime that appears unwarranted, unworkable and, as discussed below in some detail, beyond our lawful authority. And they would have us act in a way that may well frustrate the ongoing efforts to deal with these problems and would frustrate the benefits to be derived from the rule.

The CCAP asserts that FERC should establish an emissions monitoring program for NO_X and CO_2 and implement an emission neutrality requirement (ENR) to mitigate what it believes to be the impacts of the rule. The monitoring program would require generators to identify emissions associated with off-system sales on a kWh basis in real-time and integrate this information with the data to be made available on electronic bulletin boards (EBBs). Under the ENR aspect of CCAP's proposal, to be eligible for service under open access tariffs, companies that operate plants upwind from the Northeast OTR and the upper Midwest would have to certify that firm and economy off-system power sales using an open access tariff would have no incremental impact on ozone compliance in other areas. All sales for resale that require service under an open access tariff and originate upwind of the OTR would need to include NO_X emissions reduction credits equal to the increase in emissions related to those sales. The seller could meet its requirement to be "emission neutral" under the mechanism by achieving the required emission reductions annually at their own facilities, or through purchases of credits anywhere in the airshed.

EPA proposes two mitigation alternatives. In the first, it states that FERC could deny open access service unless there is a showing that the service will not have an adverse environmental impact. Under this approach, EPA, in cooperation with the states in OTAG, would recommend and establish a mitigation mechanism that could be entered into by a customer seeking open access service and used by such customer to make the necessary environmental demonstration supporting the provision of the service. The FERC would rule on whether the mitigation mechanism presented by the customer and the evidence on the likely effectiveness of the mechanism were sufficient to make the environmental demonstration.

In the second proposal, EPA suggests that any fossil fuel-burning generating entity seeking service under open access transmission tariffs would be required to commit by an enforceable contractual undertaking that it will avoid or offset emission increases (measured against as yet undetermined baselines), and periodically certify its compliance with that commitment. Middlemen would have a similar obligation. The generator could meet its emission limits either by making verified emission reductions within its own facilities or by obtaining eligible emissions offsets from other entities. An important element of the mitigation mechanism is the emissions baseline above which mitigation would be required. This mitigation mechanism would operate until superseded by appropriate programs addressing these pollution problems under other authority. EPA's own comments on the DEIS recognize that there may be substantial practical complexities in implementing such mechanism.

The Joint Commenters propose a flexible mitigation strategy pursuant to which FERC would require as part of open access transmission a demonstration that NO_X emissions would not be increased. To qualify for open access transmission access, an electric generating unit would be ***21681** responsible for mitigating any excess NO_X emissions that adversely affect ozone non-attainment areas. Utility systems would be able to comply by use of emission control technology, fuel changes, or other measures to reduce applicable emissions, or by buying appropriate emission reduction credits to offset excess emissions. To comply with this policy, a company would need first to calculate whether it had excess emissions for the ozone season. A company that failed to mitigate would be required to remit to a regional emissions fund all revenues in excess of the incremental operating cost of producing electricity sold under the open transmission access policy during the previous ozone season plus an emissions make-up penalty the following year patterned after the penalty for excess emissions in the Acid Rain Program. The proposed mitigation policy would apply generally throughout the OTAG region.

The outlines of Sustainable FERC's proposal are vague, but it appears to request that FERC, either singly or in combination with other agencies, eliminate the different environmental standards that apply to entities participating in open access transmission. This plan would include the reporting of emissions data to EPA, principles to eliminate the adverse impacts of non-comparable environmental standards, and an EPA-administered emissions monitoring process designed to determine whether generating plant emissions of specific pollutants under open access exceed designated baselines.

Finally, DOE proposes action under the Clean Air Act as the most effective mitigation of the inter-regional NO_X transport problem. DOE supports the activities of OTAG and believes that a regional NO_X cap and trading system is a particularly promising approach. If OTAG does not succeed in addressing the problem, EPA should consider exercising its authority under sections 110 and 126 of the Clean Air Act, 42 U.S.C. 7410 and 7426, respectively, to require states to amend their State Implementation Plans to reach the same result.

The proposals advanced by CCAP, EPA, Sustainable FERC, and Joint Commenters suffer from practical and legal problems that render them unworkable. A common thread is for the Commission to "level the environmental playing field." "Impacts of non-comparable environmental standards" are not impacts of this rule, but rather of the Clean Air Act regulations and statutory requirements under which those standards have been imposed. We have no authority to "level" the different emissions standards for different types of power plants, when those differences in standards are the direct result of the program adopted in the Clean Air Act and regulations promulgated by EPA. In enacting the Clean Air Act, Congress chose not to impose identical emission standards on all electric utility powerplants, but did create mechanisms for regulation of certain pollutants that can be used to "level the playing field" if that is appropriate clean air policy. For the Commission to presume to overturn those standards or seek to impose more stringent standards is something the Commission believes it cannot do.

A fundamental problem that plagues several proposals is the difficulty in identifying causation. While it is generally accepted that there is a link between increased emissions in certain areas of the country and increases in ozone levels in other areas, that link is in many respects poorly understood. In particular, it is difficult to prove that emissions from a particular unit or particular system contribute to ozone noncompliance elsewhere. As a result, it is very difficult to establish an analysis that would support a certification that a particular power sale would have no incremental impact on ozone compliance.

Similarly, the proposals tying "emission neutrality" to "open access transactions" seem to fundamentally misunderstand the operation of power markets and the role of open access tariffs in moving power from willing sellers to willing buyers. In particular, these proposals do not reflect the difficulty in identifying the transactions that are likely to result from the open access policies adopted in this rule. The rule does not authorize sales for resale of electric energy; rather, it establishes requirements for open access transmission, i.e., it requires utilities with monopoly control of transmission to make transmission service available to customers who want to buy power from someone other than the transmission owner. Open access will facilitate transactions where the transmission owner will not provide service. However, generators do not necessarily have to request service under a Commission ordered open access tariff to make specific sales. There are a number of ways to structure transactions where third party transmission service is either not necessary or is voluntarily available.[FN990] Even when open access tariffs are used, the sales are not always (or even often) sales from specific generators to specific buyers. Marketers or brokers can buy generation from any number of sources. They can also buy transmission service in blocks that may not be associated with specific sales.

Service agreements can be executed that allow use of non-firm transmission service for transactions that are not even known at the time of the execution of the agreement.

The rule envisions a world where transmission will be arranged with minimal transaction cost. Terms, conditions, rates, and even approvals often will be established far in advance of particular transactions. All other problems aside, requiring showings of the kind required by the various mitigation proposals would undermine the basic philosophy behind the rule, would make transactions much more difficult to engage in, would increase transaction costs, and would cause delays resulting in lost efficiencies. In addition, it would directly conflict with the Commission's responsibility under the FPA to remedy undue discrimination in jurisdictional services, which is the fundamental purpose of the rule.

Another significant issue with several of the proposals is how to establish the baselines against which to measure emissions. Establishing such baselines is extremely difficult; EPA itself, for example, has not come to grips with these complexities. The picture is complicated by difficulties in identifying open access transactions that result from the policies implemented by this rule. For example, some utilities use holding company corporate structures in which generation assets are held in an affiliate that sells power at wholesale to the holding company's distribution affiliate. For these utilities, all retail native load service would be subject to environmental review under the mitigation proposals if the base were established by reviewing all wholesale sales. This would make the Commission responsible for addressing all NO_X emissions from power plants for utilities with such corporate structures, a result that goes far beyond the stated goal of mitigating emissions that result from increased interstate trade facilitated by the rule.

As the industry changes, new structures are emerging that will make any system that tries to keep track of wholesale sales even more difficult to administer. California is putting into place an industry structure that could see all generation in the state sold into a central pool and then sold again at wholesale to distributors. Other states ***21682** are contemplating retail market structures that are even more fluid than the California proposal. Differentiating between sales for resale that are for former retail customers and sales for resale that are for “new” wholesale customers, and therefore somehow the result of open access policies, would be extremely difficult. In general, it is not easy to distinguish among growth in generation for native retail load, wholesale requirements customers, existing economy sales, and new sales that are facilitated by the rule, either for purposes of establishing a baseline or for tracking responsibility for emissions.[FN991]

Joint Commenters proposal would have the Commission impose a revenue collection measure—in essence a tax on open access transmission. The Commission is authorized by the FPA to pass through costs, not to collect additional fees from entities utilizing programs established by the Commission. The payment of emission fees is outside the Commission's authority under the FPA.

The FEIS concludes that mitigation by the Commission should not be undertaken in this rule because:

- Any mitigation measures the Commission might undertake are not justified by the small impacts of the rule, which impacts are as likely to be beneficial as they are to be harmful;

- The impacts of the proposed rule are dwarfed by the far larger ozone and NO_X emission issues that either have nothing to do with the electric industry or will be unchanged by the rule or the larger open access program. We believe that it would be ineffective to address the NO_X and ozone issues in a piecemeal way;

- The NO_X issue is part of a long-standing, difficult set of inter-regional environmental issues. Representatives of many interests have invested substantial efforts toward finding acceptable solutions through the OTAG process. Any mitigation the Commission might undertake could usurp EPA's mandate under the Clean Air Act and undermine progress towards comprehensive solutions sought by OTAG. This is not justified by impacts that are small and just as likely to be positive;

- We do not agree that the frozen efficiency reference case should be substituted for the EIS base cases or that competitive forces will favor coal over the next 15 years. But even accepting these assumptions, emissions attributable to the rule are relatively small until well after the turn of the century. So, even accepting such assumptions, the staff believes it would be unreasonable for the Commission to adopt mitigation requirements as part of the final rule; to do so would be tantamount to assuming that EPA and OTAG will not implement reasonable control measures in the next ten to 15 years;

- The Federal Power Act and NEPA, either singly or conjointly, do not authorize the Commission to adopt and implement the proposed mitigation measures. The Commission does not possess (and has no mandate to possess) expertise on the extremely difficult issues involved in atmospheric chemistry and transport. It is fundamentally an economic regulatory agency. As a result, any mitigation measures the Commission undertook would be based on less-than-ideal information and analysis. It is unreasonable for the Commission to attempt such mitigation given the impacts found in this FEIS. This is especially true in light of the substantial additional research that EPA and OTAG are undertaking on the basic nature of the problem;

- Some suggested mitigation measures that might work at the transaction level would undermine the purpose of the rule. There is no justification for endangering the substantial benefits projected from the rule to mitigate a problem that might not exist and that is, in any case, likely to be small.[FN992]

In sum, the rule is expected to have small impacts and those impacts are as likely to be beneficial as they are to be harmful. Therefore, mitigation is not required. In addition, processes are in place to address the pre-existing NO_X problem—a problem that dwarfs any impacts the Rule might have. These processes are expected to address the underlying transport problems well before any potential harmful effects of the rule will develop.[FN993]

The mitigation measures that certain commenters urge the Commission to adopt are truly unwarranted in light of these facts. They also fail to recognize or adequately consider the Commission's limited jurisdiction, its lack of expertise required to assess and address the underlying problem, the existing mechanisms and efforts to address the underlying problem, and the balance that has been reached and continues to be defined by the many interests that have invested substantial efforts toward finding acceptable solutions to these problems.

3. Legal and Policy Considerations

The FEIS concludes that the mitigation measures recommended by commenters are beyond our authority to implement and that strong policy considerations militate against their adoption. We agree.

Several commenters contend that the Commission is authorized to use the rulemaking as a vehicle to impose an air emissions regulatory regime on the electric utility industry.[FN994] Others argue that, as a matter of law and policy, we cannot and should not impose such measures.[FN995] While the conditioning proposals vary in specifics, all have as their central theme that generators would be forced to agree to operate generation facilities in a manner to reduce air pollution below levels currently authorized by EPA and the states.[FN996]

The Commission's authority to regulate public utilities is set out in Parts II and III of the FPA. Parts II and III do not provide the Commission with the authority to condition either the provision of, or access to, jurisdictional services on the agreement to undertake environmental mitigation measures.[FN997] Section 201, which is found in Part II of the FPA, explicitly bars the Commission from exercising the jurisdiction that the proponents of the conditioning ***21683** proposals would have us undertake: authority over the operation of generating facilities. Section 201(b)(1) provides that:

The Commission shall have jurisdiction over all facilities for (the transmission of electric energy in interstate commerce) or (the) sale of electric energy (at wholesale in interstate commerce), but shall not have jurisdiction, except as specifically provided in (Parts II and III), over facilities used for the generation of electric energy * * *. (emphasis added).

This standard is reflected throughout Parts II and III of the FPA. Sections 205 and 206, which are the cornerstones of Parts II and III, concern the regulation of rates, terms and charges occurring in connection with transmission or sales subject to the Commission's jurisdiction. Parts II and III do not grant the Commission authority to regulate the environmental aspects of jurisdictional activities.[FN998] Instead, they provide authority over certain interconnections;[FN999] the rates, terms and conditions of wholesale sales of electric energy in interstate commerce and transmission in interstate commerce; the disposition and merger of facilities used for such sales and transmission; issuance of securities; accounting matters; and interlocking directorates. Thus, the Commission's jurisdiction over generation extends only to matters directly related to the economic aspects of transactions resulting from such facilities.[FN1000] We do not have jurisdiction over the physical aspects of generation facilities.[FN1001]

This limitation on the Commission's jurisdiction stems from the historical purposes for which the Commission was established. Congress had two objectives in expanding the authority of the Federal Water Power Commission in 1935.[FN1002] The first was to close the gap created by Public Utilities Commission v. Attleboro Steam & Electric Co., 273 U.S. 83 (1927)(Attleboro), in which the Court found that under the Commerce Clause states could not regulate wholesale sales of electricity in interstate commerce. The result was a gap in regulation of such sales because there was no federal entity with authority to regulate them at that time. The second was to eliminate the economic abuses that were then rampant in the industry.[FN1003] In expanding the Commission's jurisdiction Congress made clear that such Federal regulation, however, was "to extend only to those matters which are not subject to regulation by the States."[FN1004]

Several commenters argue nonetheless that the Commission may do indirectly what it is barred from doing directly. Their arguments boil down to the claim that the Commission's responsibility under the FPA to act in the "public interest", either alone or in conjunction with NEPA, provides the Commission with the authority to impose environmental regulation on generators to address the supposed impacts of the Rule.[FN1005] We disagree. In making this argument, the commenters attribute to that standard a breadth of discretion that vastly exceeds the traditional ambit of our authority.

It is well established that NEPA merely establishes a procedural vehicle for assessing the impacts of a proposed action on the environment. It neither expands nor contracts the basic grant of jurisdiction made by Congress to the agency conducting the review, and it does not mandate particular results but simply prescribes a process.[FN1006] Commenters' arguments that NEPA somehow "fills in the blanks" of the FPA to authorize us to impose environmental regulatory regimes on generating facilities, or those who may purchase power from them, is simply incorrect. If we have such authority, it must be found in our substantive statute, the FPA.

Courts have addressed the breadth of our public interest standard on several occasions. The principal case on this point is National Association for the Advancement of Colored People v. FPC 520 F.2d 432 (D.C. Cir. 1975), aff'd, 425 U.S. 662 (1976) (NAACP). In NAACP, a number of organizations requested that the Commission promulgate regulations requiring equal employment opportunity and proscribing racial discrimination in the employment practices of public utilities.[FN1007] The Commission declined, finding that the FPA did not authorize it to do so. Petitioners appealed, contending that the Commission was authorized and required to act in the public interest: to order such interconnections of electric power transmission facilities, setting such terms and conditions for the same, as are "necessary or appropriate in the public interest"; to approve such asset sales and consolidations of interstate electric power companies as are "consistent with the public interest; to approve such securities issuances by those companies as are "compatible with the public interest" and "consistent with the proper performance * * * of service as a public utility"; to determine "just and reasonable" rates for interstate sales and transmission of electric power; and to order that "proper, adequate or sufficient" interstate power service be rendered.[FN1008]

On this basis, they argued that because prohibition of discrimination is in the "public interest," the Commission was therefore required to proscribe discrimination by jurisdictional entities.

The Court rejected petitioners' argument. It observed that: the (Federal Power) Act's preamble echoes the generality of the foregoing quoted ***21684** phrases, declaring that the sale and transmission of electric power are "affected with the public interest," federal regulation of interstate aspects being "necessary in the public interest." The statute itself nowhere defines the "public interest," but instead leaves the precise ambit of the Commission's concern uncertain.[FN1009]

The Court found from the entirety of the Act that, "(o)f the Commission's primary task there is no doubt, however, and that is to guard the consumer from exploitation by non-competitive electric power companies."[FN1010] The Court reiterated that "(t)he Supreme Court has stated that the words 'public interest' do not constitute a 'mere general reference to the general welfare, without any standard to guide determinations.'"[FN1011] Significantly, the Court also found that "(w)ords like 'public interest' * * * though of wide generality, take their meaning from the substantive provisions and purposes of the Act."[FN1012] The Court concluded that:

Congress has not charged the Commission with advancing all public interests, but only the public's interest in having the particular mandates of the Commission carried out, its interest, in other words, in the conservation of natural resources and the enjoyment of cheap and plentiful electricity and natural gas.[FN1013]

With this, the Court rejected petitioners' argument that the FPA "public interest" standard requires the Commission to promulgate regulations prohibiting discriminatory practices by entities who are in some way regulated by the Commission. The Court found that the Commission was not empowered to promulgate anti-discrimination regulations because to do so would not be "reasonably related to the furtherance of the Commission's proper objectives," which, under Part II of the FPA, are "the enjoyment of cheap and plentiful electricity."[FN1014]

On review, the Supreme Court affirmed this limited reading of the Commission's authority to act in the public interest.[FN1015] In doing so, the Court noted that:

The use of the words "public interest" in the Gas and Power Acts is not a directive to the Commission to seek to eradicate discrimination, but, rather, is a charge to promote the orderly production of plentiful supplies of electric energy and natural gas at just and reasonable rates.[FN1016]

The question the Supreme Court asked in NAACP is the appropriate question here concerning the commenters' environmental mitigation proposals:

The question presented is not whether the elimination of discrimination from our society is an important national goal. It clearly is. The question is not whether Congress could authorize the Federal (Energy Regulatory) Commission to combat such discrimination. It clearly could. The question is simply whether and to what extent Congress did grant the Commission such authority.[FN1017]

We believe the same conclusion is true here for air pollution as the Court found there regarding discrimination.[FN1018]

The argument by EPA and others that because the FPA authorizes the Commission to act in the "public interest" it somehow authorizes the Commission to impose environmental mitigation measures is virtually indistinguishable from petitioners' argument in NAACP.[FN1019] Here, as in NAACP, parties urge the Commission to act to achieve worthwhile goals. However, the question is not whether the measures proposed by the parties would advance important national goals. Rather, "[t]he question is simply whether or to what extent Congress did grant the Commission such authority."[FN1020] Also here, as in NAACP, the parties improperly base their belief that the Commission has authority to act under the FPA on an incorrect, overly broad application of the "public interest" standard. The goals sought to be advanced by EPA and others are broadly speaking "in the public interest," but they are not goals that Congress has directed this Commission to pursue.[FN1021] Thus, just as the FPA did not authorize the Commission to take actions that petitioners requested in NAACP, the FPA does not authorize the Commission to undertake the types of environmental mitigation measures proposed by the commenters.[FN1022]

***21685** The Project for Sustainable FERC argues that in Richmond Power & Light v. FERC, 574 F.2d 610, 616-17 n.22 (D.C. Cir. 1978) (Richmond Power), the Court "suggested" a broader agency latitude than described in NAACP.[FN1023] We disagree.

Richmond Power involved a case where the Commission was challenged, inter alia, because it declined to adopt a particular transmission rate that would have permitted Richmond to shift from oil to some other fuel. The Court affirmed the Commission's decision, finding that:

Although the Commission must serve the public interest in approving rates, we see no abuse of discretion in limiting this proceeding to the shortrun problem of setting just and reasonable rates for the service theretofore provided in response to the 1973 oil embargo. While an administrative agency must remain faithful to public policies directly related to its regulatory authority, surely at any given moment of history it may rationally decline to affirmatively foster other policies in weighing the specific interests that it is required by the statute to consider. This is especially true when the forum chosen by proponents of the other policy is not well suited to the study of its implications.[FN1024]

In dicta, in a footnote that began with the Court doubting whether the goal of energy independence is within the Commission's regulatory jurisdiction at all, the Court merely said that "(n)othing in NAACP v. FPC, supra, forecloses agency discretion to consider in given situations pervasive public policies that it is not required to evaluate in every decision it makes."[FN1025] The discretion to consider public policy matters is a far cry from the authority, or obligation, to regulate those matters. We have considered the environmental impact of the rule. Nothing in Richmond Power suggests that the consideration of such matters conveys an affirmative grant of broad new regulatory powers to develop and implement a comprehensive regulatory program in an area expressly assigned by Congress to another agency.[FN1026]

The cases rejecting commenters' broad reading of our public interest authority are supported by the decision in Office of Consumers' Counsel v. FERC, 655 F.2d 1132 (D.C. Cir. 1980) (Great Plains). There, the Court found that, even under the explicit "public interest" standard in section 7(a) of the Natural Gas Act, the Commission is not granted power to act on matters outside of its statutory mandate.[FN1027]

In Great Plains, the Court reviewed a Commission decision to grant a certificate of public convenience and necessity to facilitate construction and operation of a coal gasification plant. Although the NGA does not explicitly provide the Commission with authority to certificate coal gasification projects, the Commission reasoned that it had such authority because the demonstration project was "in the public interest" and, because the Commission was authorized under section 7 of the NGA to "consider" all factors in reaching a decision on whether to grant the certificate, it had the requisite authority to act.

The Court rejected the Commission's reasoning in that case, stating that:

Any such authority to consider all factors bearing on the "public interest" must take into account what the "public interest" means in the context of the Natural Gas Act. FERC's authority to consider all factors bearing on the public interest when issuing certificates means authority to look into those factors which reasonably relate to the purposes for which FERC was given certification authority.[FN1028]

The Court repeated the finding in NAACP that the Commission's authority to act in the public interest is limited to the furtherance of the purposes for which its organic statutes were adopted.[FN1029]
In concluding that the Commission was not authorized to act as it did, the Court looked to several factors. The Court found it persuasive that Congress had specifically authorized a different governmental entity, the Synthetic Fuels Corporation, to provide support for coal gasification, and that Congress had carefully crafted a special means for providing federal financial assistance for synfuel development.[FN1030] The Court also found it persuasive that the Commission possessed no expertise in making determinations regarding the relative merits of different synfuel processes, methods or technologies, and that the financing arrangements "were certainly not ordered with the interests of ratepayers foremost in mind."[FN1031] The Court stated that "by utilizing its statutory tools for a non-statutory purpose, FERC very likely was distracted from its primary statutory duty to protect the interests of ratepayers." [FN1032] Finally, the Court found that the Commission's action seemed to have been prompted at least in part by an attitude that, because Congress had not acted speedily, the Commission could act. The

Court criticized the Commission for improperly attempting to preempt Congressional action and to "fill in" *21686 where the agency believed federal action was needed.[FN1033]

The facts and reasoning in Great Plains are directly analogous to this proceeding. Congress has specifically authorized other entities—EPA and the states—under other statutes to address air pollution. The Commission is being urged to regulate in an area in which, as in Great Plains, it possesses no special expertise (i.e., in making determinations regarding appropriate air pollution control mitigation measures) and in which it is not authorized to act.[FN1034] Finally, as in Great Plains, if the Commission were to undertake mitigation, it would be diverted from its primary statutory duty to protect the economic interests of ratepayers, i.e., by having to continually monitor compliance with mitigation conditions.[FN1035]

As in Great Plains, the Commission is being urged to act at least in part because of the belief that Congress has not provided a sufficiently speedy process by which to regulate air pollution produced by electric utilities. The EPA argues that:

Regulations under the Clean Air Act must in general be implemented through State Implementation Plans; the time from reaching a general conclusion that control is needed to adoption of necessary regulations by states generally takes from three to five years; that regulatory lag time means compliance with new rules can be, and usually is, more than a decade from the point at which the problem occurred. Ten years of bad air is ten years delay too many.[FN1036]

That Congress has imposed upon the EPA procedures that the EPA and others find burdensome and overly time consuming is an issue for Congress and EPA to address, not the Commission.[FN1037]
This conclusion has particular force when, as here, we are urged to impose environmental restrictions on certain coal-fired generators in spite of Congressional actions regulating those entities. In essence, some commenters argue that under a very tenuous connection to the public interest standard of the FPA we may undertake to do more than the agency that Congress has authorized to act on such matters. This result is not a correct reading of the law and we reject it.

Several commenters attempt to overcome the various Courts' views of the scope of the public interest standard under the FPA by arguing that there is a "direct nexus" between the Rule and environmental concerns that suffices to invoke an imputed authorization under the FPA to prescribe environmental requirements on generators.[FN1038] To this end, they argue that the purpose of the rule is really to facilitate the least-cost use and construction of generation resources and that the environmental consequences of these actions will impact economic efficiency, rates, competition, and competitive markets. Thus, they conclude that we have the authority to require that those who seek to obtain transmission access on a non-discriminatory basis must first mitigate air emissions under as yet undefined standards.

These commenters misstate the question. The question is not whether there is a nexus between the rule and environmental concerns. Clearly, electric utilities contribute to pollution; anything that facilitates the sale of power from whatever source is, under this tenuous logic, "related" to environmental concerns.[FN1039]

However, as discussed below, Congress did not give us plenary powers over public utilities to shape their activities in response to a broad range of public policy concerns. The nexus that must be established is a nexus between the requirements sought to be imposed, in this case emission controls, and the statutory standards which authorize us to act. That is, in order to impose the environmental conditions sought by commenters, a direct connection must be established between those conditions and our duty to determine that the rates, terms and conditions of service under our open access tariffs are not unjust, unreasonable, unduly discriminatory, or preferential.

It is on this point that commenters' arguments founder. While the Commission has broad latitude to interpret these standards to advance the interests of ratepayers, we cannot implement policy objectives that are not assigned to us and that are, in fact, clearly assigned to other entities. The Congress has assigned responsibility for environmental regulation of air quality to EPA and the states; it has explicitly charged them with dealing with such pollution from electric generating facilities. While, as noted earlier, we do not dispute the need to give appropriate weight to environmental considerations in making decisions within our authority, we cannot use that authority to accomplish public policy objectives that, by statute, are required to be implemented and administered by other agencies.[FN1040]

*21687 Some commenters have sought to address this issue by characterizing the proposed conditions as necessary to create a level competitive playing field among generators. For example, Alliance argues that unless the Commission requires environmental mitigation certain competitors in the bulk power market (those with "dirty generation") would be favored over "clean" competitors. It argues that:

Mitigation of the environmental impacts resulting from the NOPR has a direct relationship to ensuring that open access is implemented under terms of economic fairness for all utilities and utility consumers, and not merely those with current low-cost regulatory advantages.[FN1041]

We note that all power generation technologies have different costs. For example, hydroelectric facilities which, like coal-fired facilities, may have environmental mitigation conditions imposed on them, may be quite expensive to build compared to gas or oil-fired generation, but their operating costs may be significantly lower. These cost differences may reflect the different costs of complying with mandated environmental requirements; the prudent costs of complying with such mandates may be reflected in rates.
Indeed, sellers come to the power markets with a variety of advantages and disadvantages, many of which are the result of federal laws—for example, tax preferences, labor standards, and similar matters. In empowering the Commission to remedy undue discrimination and promote competition, Congress has not authorized the Commission to equalize the environmental costs of electricity production in order to ensure "economic fairness." Such homogenization of competitors, or their costs, has never been a goal of the FPA.[FN1042]

In short, the "economic nexus" urged by commenters advocating that the Commission undertake to regulate air emissions is inconsistent with the "charge to promote the orderly production of plentiful supplies of electric energy" envisioned by the FPA.[FN1043]

We have exercised conditioning authority in the past only where necessary to ensure that jurisdictional transactions and rates do not result in anti-competitive effects, or are not unjust, unreasonable or unduly discriminatory or preferential.[FN1044] Thus, the conditions we have imposed have involved economic regulatory matters within our purview under the FPA.[FN1045] Any exercise of conditioning authority must, as the Supreme Court noted in NAACP, be directly related to our economic regulation responsibilities; EPA and the other commenters have not demonstrated such a nexus.[FN1046]

This distinction is more evident when one considers the way in which we are authorized to treat the costs of environmental compliance. There are legitimate costs of environmental compliance that should be reflected in jurisdictional rates to the extent prudently incurred, just as the prudent costs of complying with, for example, occupational health and safety requirements designed to protect utility employees should be reflected in jurisdictional rates. This we are authorized to do and we routinely review and allow such costs.[FN1047] However, the fact that the costs of providing utility workers with a safe workplace are properly reflected in utilities' jurisdictional rates does not mean that we have authority to condition sellers' rates or customers' use of jurisdictional services on meeting safety regulations that are in the public interest. The same rationale applies to environmental matters related to the rule.[FN1048]

Commenters also raise several other arguments to support the claim that the Rule requires us to undertake environmental regulation to remedy supposed impacts of the rule. EPA, for example, argues that requiring environmental mitigation would not run afoul of the prescription of section 201(b)(1) of the FPA enjoining our regulation of generation facilities because the "regulation of transmission tariffs necessarily has manifold indirect effects on generation sources. The proposed mitigation mechanism would influence generation sources in a similar, indirect manner."[FN1049]

EPA fundamentally misunderstands the purpose of the Rule. We act to remedy unduly discriminatory practices in, as here for example, the provision of transmission access. Since "undue discrimination," is one of the matters "specifically provided in this Part (II)", i.e., in FPA sections 205 and 206, we are acting within the bounds of our statutory mandate and the effect that the Rule may have "over facilities used for the generation of electric energy" is specifically sanctioned. Indeed, many generators are transmission customers who we are obliged to protect under the FPA. That there may be indirect environmental consequences from our Rule does not trigger our jurisdiction under the FPA.

***21688** EPA next argues that, even if we could not impose a specific mitigation mechanism for open access transmission, we could deny transmission service unless there is a showing that the service will not have an adverse environmental impact.[FN1050]

We have already discussed why we believe this approach is unworkable and inconsistent with sections 205 and 206 of the FPA.[FN1051] Plainly stated, EPA would have transmission customers assume an additional regulatory burden in order to be treated lawfully.[FN1052] Quite apart from this fundamental problem, such a regime is beyond our authority. Our regulation under sections 205 and 206 is over the selling public utility's rates, terms and conditions, not over the buyer's agreement to undertake measures which have no nexus whatsoever with the seller's costs or terms of service.

EPA states that its alternative mitigation mechanism would not be a condition of the open access tariff, but apparently a condition on the ability of customers to take service under the tariff. However, our authority to set terms and conditions of eligibility derives from precisely the same authority that we use to set other tariff terms. It must still be based on a nexus with the subject matter of our jurisdiction. For buyers, open access is a right, not a privilege. We fail to see, given the direction of the FPA to ensure these rights, any basis for us to undertake the actions EPA proposes.

Finally, EPA points to the Commission's decision to exclude certain diesel facilities in defining qualifying facilities (QF) under PURPA section 210.[FN1053] However, this provides no precedent for imposing environmental standards to prevent customers from obtaining nondiscriminatory open access. Whatever the merits of that decision,[FN1054] the Commission subsequently found that any facility that satisfies the ownership and technical requirements for QF status set forth in PURPA and the Commission's regulations is a QF without any action by the Commission.[FN1055] More to the point, EPA ignores the fact that, in issuing environmental findings with its QF Rules, the Commission found that environmental concerns were a local matter to be handled under other statutory authorities. While PURPA permitted certain qualifying facilities to be exempt from state and federal laws, it excludes exemptions from environmental laws. Thus, a qualifying facility may not be built or operated unless it complies with all applicable local, State, and Federal zoning, air, water, and other environmental quality laws, and unless it obtains all required permits.[FN1056]

Thus, while we have noted that QFs are required to satisfy all environmental requirements, we have not viewed our responsibilities under PURPA as permitting us to enforce compliance with environmental laws.[FN1057]
EPA then proposes to require any fossil fuel-burning generating entity seeking service under an open access tariff to (a) commit by contract to avoid or offset emissions increases (measured against certain baselines), and (b) periodically certify its compliance with that commitment.[FN1058] This proposal is neither workable nor within our jurisdiction.

The deficiency with respect to (a) is that we have no authority to require such action. While EPA cites to FPA section 206 for the proposition that we may change jurisdictional contracts, we may do so only if the contract is, for example, unjust or unreasonable with respect to matters within our jurisdiction, i.e., economic regulation. Our standards for acting are strictly prescribed under the FPA.[FN1059] As NAACP and Great Plains teach, sections 205 and 206 do not provide the Commission with the means to remedy every possible problem that is in any fashion related to a sale for resale or transmission in interstate commerce by a public utility. Since we do not have the authority to require (a), it follows we cannot require the periodic certification of compliance recommended in (b).

EPA notes that it "could establish a procedure whereby a generator could voluntarily subject its facilities to emission limits that are enforceable by EPA and/or state environmental authorities."[FN1060] This is a matter within EPA's province, and we support EPA in undertaking whatever measures it determines to be within its authority and appropriate to the problem.

Alliance argues, at 47-51, that sections 211 and 212 of the FPA, as amended by the Energy Policy Act, authorize the Commission to impose environmental conditions. To the extent that Alliance's arguments rely on the "public interest" language used in section 211, we believe that the discussion above already addresses such arguments, with one exception: Alliance argues that the House Report for the Energy Policy Act states that the purpose of the Act is to "increase U.S. energy security in cost-effective and environmentally beneficial ways ***21689** * * *."[FN1061] However, even if we assume that the Report language reflects Congressional intent for the Energy Policy Act in general, we note that, in Title VII of the Energy Policy Act concerning electricity, the only mention of the environment was, as noted above, in section 731 which specifically provided that nothing in the Energy Policy Act in any way interferes with the authority of any state or local government relating to, inter alia, environmental protection. While we do not quarrel with the proposition that Congress in the Energy Policy Act obviously had concerns with environmental matters,[FN1062] Congress did not provide the Commission with any authority to mandate environmental mitigation.

We have undertaken an extensive NEPA analysis to consider the environmental effects of our Rule. We cannot, however, take NEPA's requirement to consider environmental effects as authority to require the environmental mitigation proposed in the comments. Congress has charged other agencies, most notably the EPA, with the responsibility of protecting the environment and enforcing environmental laws.[FN1063] While we stand ready to work in a complementary fashion with these agencies, we believe that any attempt by the Commission to go beyond the economic regulation that Congress has delegated to us would be ultra vires.

To summarize: The Commission's jurisdiction under Parts II and III of the FPA is limited to matters relating to economic regulation. Neither the relevant statutes nor the case law supports the expansive and novel reading of the Commission's authority advocated by the commenters that argue that we have environmental mitigation authority. The Commission is not explicitly given such authority in either the FPA or NEPA. Moreover, the FPA and the case law clearly compel the conclusion that we cannot impose environmental conditions that do not directly relate to the economic matters over which we have jurisdiction. To do so, in fact, would prevent the Commission from effectively carrying out its responsibilities under the FPA.

F. Coastal Zone Management Act Issue

By letter dated February 22, 1996, and filed with the Commission on March 5, 1996, the Connecticut Department of Environmental Protection (Connecticut) notified the Commission that it has determined that the Commission's proposed action in this rulemaking proceeding is likely to adversely affect Connecticut's coastal resources. Connecticut reasons that the Rule's promotion of competition "is likely to increase energy production by mid-west coal burning plants(,) which will in turn increase the export of nitrogen and sulphur oxides." Connecticut states that airborne nitrogen emissions are linked to adverse environmental impacts in Long Island Sound. It therefore asserts that, pursuant to section 307(c)(1) of the Coastal Zone Management Act (16 U.S.C. 1456(c)(1)) (CZMA), and the federal regulations promulgated thereunder (15 CFR part 930), the Commission is required to provide it with a determination of the Rules' consistency with Connecticut's federally approved coastal management plan.

Section 307(c)(1)(A) of the CZMA deals with the prevention or amelioration of adverse physical impacts on coastal zone resources attributable to federal activities. The legislative history indicates that in enacting the CZMA Congress was concerned with the adverse effects on coastal lands and waters of such activities as excavation, filling, diversion of water or sediment, clearing, and off-shore energy exploration and dumping.[FN1064]

As discussed more fully above, section 201 of the FPA declares that the Commission shall not have jurisdiction over facilities used for the generation of electricity except as specifically provided. Thus, the Commission has no direct jurisdiction over fossil-fuel plants. Its jurisdiction extends only to the rates, terms, and conditions of wholesale sales and transmission of electric energy in interstate commerce from those plants. While we are aware that the legislative history of the CZMA indicates a Congressional intent to cover all federal activities, there is absolutely no indication in the CZMA or its legislative history that "federal activities" should include all federal regulatory decisions, including Commission orders involving interstate electric rates and service (or any other jurisdictional matter under Part II of the FPA).[FN1065] We are not aware of any judicial or agency interpretation that would cast the net of the states under the CZMA broadly enough to include the generic federal regulatory action undertaken in this Rule. Such action is clearly remote from the kind of activities such as leasing of land, and dredging and filling that either affect, or authorize specific activities that affect, the environment in the coastal zone.

Connecticut's attempt to pull FPA Part II regulation into the CZMA federal consistency provisions by dint of the rulemaking's alleged adverse impact on air quality and consequent adverse impact on water quality in the coastal zone is untenable in view of the existence of the Clean Air Act, a complex, 700-page environmental law that constitutes a comprehensive scheme of regulation of the Nation's air quality, including the direct regulation of emissions by utility power plants. Indeed, the CZMA provides that the requirements of the Clean Air Act, and governmental directives pursuant to that Act, shall be incorporated in, and shall be the air pollution control requirements of, all state coastal zone ***21690** management programs.[FN1066] It therefore defies logic to assert that, despite the pervasive regulatory reach of the Clean Air Act and the clear authority of EPA to regulate NO_X emissions under that statute, the CZMA is a separate source of authority for state jurisdiction over air quality impacts to coastal zones.

While it is clear that Connecticut's invocation of the CZMA is incorrect, we note that, under the Commerce Department's implementing regulations, Connecticut has in any event waived its right to request a consistency determination for the Commission's rulemaking. Connecticut's coastal management program's list of federal agency activities likely to require a consistency determination does not (for good reason) describe rulemakings of this kind, and the rule will not "result in a significant change in air or water quality within the management area" (the program's catch-all category). In addition, Connecticut did not notify the Commission of its conclusion that the Rule requires a consistency determination until well after 45 days from receipt of several notices of the rulemaking proceeding.[FN1067] Consequently, pursuant to 15 CFR 930.35(b), Connecticut has in any event waived its right to request a consistency determination for this rulemaking.

Conclusion

After reviewing the record in this proceeding, including the FEIS, we find for the reasons discussed above that proceeding with this rule is the best alternative. No other alternative will accomplish the Commission's purposes.

The rule is expected to slightly increase or slightly decrease total future NO_X emissions, depending on whether competitive conditions in the electric industry favor the utilization of natural gas or coal as a fuel for the generation of electricity. Other impacts of the rule have also been determined to be slight. Therefore, it is unnecessary to adopt and implement a plan of mitigation.

A wide range of mitigation measures have nonetheless been fully evaluated as discussed in Chapter 7 of the FEIS. This discussion concludes that the Commission does not have authority under the FPA and NEPA, singly or conjointly, to impose mitigation, and that existing and proposed mitigation strategies and efforts are the best way to deal with potential environmental effects that might result from implementing the rule. Such effects, if they indeed materialize, are not expected to occur for many years. In the meantime, action by entities such as EPA and OTAG are expected to address the underlying air emission problems facing parts of the Nation. Interim mitigation efforts to be undertaken by the Commission would address only a very small part of the problem, would require the exercise of technical expertise and authority that the Commission does not possess, and could well interfere with efforts by EPA and others to address this situation.

For these reasons, we support the analysis in the staff's FEIS and adopt the conclusions in that document.[FN1068]

VI. Regulatory Flexibility Act Certification

The Regulatory Flexibility Act (RFA)[FN1069] requires rulemakings to contain either a description and analysis of the effect that the proposed rule will have on small entities or a certification that the rule will not have a significant economic impact on a substantial number of small entities. In the Open Access and Stranded Cost NOPRs, the Commission concluded that the proposed rules would not have a significant economic impact upon a substantial number of small entities.[FN1070]

SBA questions this conclusion.[FN1071] It states that, "[a]ccording to data from the Department of Energy, the vast majority of utilities are small."[FN1072] SBA requests that if, upon reconsideration, the Commission determines that the final rule in the Open Access NOPR proceeding would have a significant economic impact on a substantial number of small entities, the Commission perform a Regulatory Flexibility Analysis under the requirements of the RFA.[FN1073]

A. Docket No. RM95-8-000 (Open Access Final Rule)

1. Public Utilities

The Open Access Final Rule is applicable to public utilities that own, control or operate interstate transmission facilities, not to electric utilities per se.[FN1074] The total number of public utilities that, absent waiver, would have to have open access tariffs on file is 166.[FN1075] Of these, only 50 public utilities dispose of 4 million MWh or less per year.[FN1076] Eliminating those utilities that are affiliates of other utilities whose sales exceed 4 million MWh per year, or are not independently owned, [FN1077] the total number of public utilities affected by the Open Access Final Rule that qualify under the SBA's definition of small electric utility is 19, or 11 percent of the total number of public utilities that would have to have on file open access tariffs.[FN1078] We do not consider this a substantial number,[FN1079] and, in any event, these entities may seek waiver of the Open Access Final ***21691** Rule's requirements under the Rule's waiver provisions.

Moreover, in the Open Access Final Rule, the Commission is specifying the non-rate terms and conditions of the tariffs that the public utilities must have on file. The public utilities need only develop and file a rate.[FN1080] When one considers that the disposition of 4 million MWhs a year translates into sales in the range of $120 million to $180 million per year, the cost to prepare and file proposed rates,[FN1081] which these utilities must regularly do anyway in the ordinary course of business, is not a significant economic impact.

2. Non-Public Utilities

The Open Access Final Rule will not impose any burden on non-public utilities, since they need not themselves file open access tariffs. Triggering the reciprocity provision in the Open Access Final Rule is optional; it is merely a condition of receiving a benefit, i.e., open access transmission service from a public utility. If non-public utilities elect not to take advantage of open access services because they do not want to meet the tariff reciprocity provision, they can still seek voluntary, bilateral transmission services from public utilities. Also, under the waiver provisions in the Open Access Final Rule, small non-public utilities may seek waiver from the reciprocity provision.

B. Docket No. RM94-7-001 (Stranded Cost Final Rule)

1. Public Utilities

As with the Open Access Final Rule, there are not a substantial number of public utilities that qualify under the SBA's definition of small electric utility that are subject to the Stranded Cost Final Rule. The Stranded Cost Rule applies only to public utilities that seek stranded cost recovery in connection with a limited set of wholesale requirements contracts (those executed on or before July 11, 1994 that do not contain an exit fee or other explicit stranded cost provision). To the extent that public utilities seek stranded cost recovery, they will do so in a rate filing, where stranded cost recovery is likely to be one of many items considered. Accordingly, the Stranded Cost Final Rule will not pose a significant economic impact on a substantial number of public utility small entities.

2. Non-Public Utilities

With regard to non-public utilities, the stranded cost issue would only arise in a proceeding under sections 211 and 212 of the FPA when, in directing transmission, the Commission addresses the stranded cost issue in determining a just and reasonable rate. As with public utilities, stranded costs will be just one more item to be considered in establishing just and reasonable rates for transmission. As a result, the Stranded Cost Final Rule will not impose a significant economic impact on a substantial number of non-public utility small entities.

C. Conclusion

Accordingly, the Commission certifies that these final rules will not have a significant economic impact on a substantial number of small entities.

VII. Information Collection Statement

The Office of Management and Budget's (OMB) regulations[FN1082] require that OMB approve certain information and recordkeeping requirements (collections of information) imposed by an agency. Upon approval of a collection of information, OMB shall assign an OMB control number and an expiration date. Respondents subject to the filing requirements of this Rule shall not be penalized for failing to respond to this collection of information unless the collection of information displays a valid OMB control number.

There are now approximately 328 public utilities, including marketers and wholesale generation entities. The Commission estimates that 166 of these utilities own, control or operate facilities used for the transmission of electric energy in interstate commerce and would be subject to the filing requirements of this Rule.

Title: FERC-516, Electric Rate Schedule Filings.

Action: Final Rule.

OMB Control No: 1902-0096.

Respondents: Public Utilities that own, control or operate facilities used for the transmission of electric energy in interstate commerce.

Frequency of Responses: On occasion.

Necessity of information: The Final Rule requires public utilities that own, control or operate facilities used for the transmission of electric energy in interstate commerce to have on file with the Commission non-discriminatory open access transmission tariffs that contain minimum terms and conditions of service and permits public utilities to make filings to seek recovery of legitimate, prudent and verifiable stranded costs associated with providing open access and FPA section 211 transmission services. The Commission has a mandate under sections 205 and 206 of the FPA to ensure, with respect to any transmission in interstate commerce or any sale of electric energy for resale in interstate commerce by a public utility, that no entity is subject to undue discrimination. The Commission will use the data collected in this collection of information to carry out its responsibilities under Part II of the FPA. The Commission's Office of Electric Power Regulation will use the data to review electric rate and tariff filings.

The Commission is submitting notification of this Final Rule to OMB. Interested persons may obtain information on the reporting requirements by contacting the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC. 20426 [Attention: Michael Miller, Information Services Division, (202) 208-1415], and to the Office of Management and Budget (Attention: Desk Officer for the Federal Energy Regulatory Commission, (202) 395-3087).

VIII. Effective Date

This Rule will take effect on July 9, 1996. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of the Office of Management and Budget, that this rule is a "major rule" within the meaning of section 351 of the Small Business Regulatory Enforcement Act of 1996.[FN1083] The rule will be submitted to both Houses of Congress and the Comptroller General prior to its publication in the Federal Register.

List of Subjects

18 CFR Part 35

Electric power rates, Electric utilities, Reporting and recordkeeping requirements.

18 CFR Part 385

Administrative practice and procedure, Electric power, Penalties, Pipelines, Reporting and recordkeeping requirements.

By the Commission. Commissioner Hoecker concurred in part and dissented in ***21692** part with a separate statement attached. Commissioner Massey dissented in part with a separate statement attached.

Lois D. Cashell,

Secretary.

In consideration of the foregoing, the Commission amends parts 35 and 385, chapter I, title 18 of the Code of Federal Regulations, as set forth below.

PART 35—FILING OF RATE SCHEDULES

1. The authority citation for part 35 continues to read as follows:

Authority: 16 U.S.C. 791a-825r, 2601-2645; 31 U.S.C. 9701; 42 U.S.C. 7101-7352.

18 CFR § 35.1518 CFR § 35.2818 CFR § 35.2918 CFR § 35.2618 CFR § 35.27

2. Part 35 is amended by revising §35.15, by redesignating §35.28 as §35.29, and by adding new §§35.26, 35.27, and 35.28 to read as follows:

18 CFR § 35.15

§35.15 Notices of cancellation or termination.

(a) General rule. When a rate schedule or part thereof required to be on file with the Commission is proposed to be cancelled or is to terminate by its own terms and no new rate schedule or part thereof is to be filed in its place, each party required to file the schedule shall notify the Commission of the proposed cancellation or termination on the form indicated in §131.53 of this chapter at least sixty days but not more than one hundred-twenty days prior to the date such cancellation or termination is proposed to take effect. A copy of such notice to the Commission shall be duly posted. With such notice each filing party shall submit a statement giving the reasons for the proposed cancellation or termination, and a list of the affected purchasers to whom the notice has been mailed. For good cause shown, the Commission may by order provide that the notice of cancellation or termination shall be effective as of a date prior to the date of filing or prior to the date the filing would become effective in accordance with these rules.

(b) Applicability. (1) The provisions of paragraph (a) of this section shall apply to all contracts for unbundled transmission service and all power sale contracts:

(i) Executed prior to July 9, 1996; or

(ii) If unexecuted, filed with the Commission prior to July 9, 1996.

(2) Any power sales contract executed on or after July 9, 1996 that is to terminate by its own terms shall not be subject to the provisions of paragraph (a) of this section.

(c) Notice. Any public utility providing jurisdictional services under a power sales contract that is not subject to the provisions of paragraph (a) of this section shall notify the Commission of the date of the termination of such contract within 30 days after such termination takes place.

18 CFR § 35.26

§35.26 Recovery of stranded costs by public utilities and transmitting utilities.

(a) Purpose. This section establishes the standards that a public utility or transmitting utility must satisfy in order to recover stranded costs.

(b) Definitions.

(1) Wholesale stranded cost means any legitimate, prudent and verifiable cost incurred by a public utility or a transmitting utility to provide service to:

(i) A wholesale requirements customer that subsequently becomes, in whole or in part, an unbundled wholesale transmission services customer of such public utility or transmitting utility; or

(ii) A retail customer, or a newly created wholesale power sales customer, that subsequently becomes, in whole or in part, an unbundled wholesale transmission services customer of such public utility or transmitting utility.

(2) Wholesale requirements customer means a customer for whom a public utility or transmitting utility provides by contract any portion of its bundled wholesale power requirements.

(3) Wholesale transmission services has the same meaning as provided in section 3(24) of the Federal Power Act (FPA): The transmission of electric energy sold, or to be sold, at wholesale in interstate commerce.

(4) Wholesale requirements contract means a contract under which a public utility or transmitting utility provides any portion of a customer's bundled wholesale power requirements.

(5) Retail stranded cost means any legitimate, prudent and verifiable cost incurred by a public utility or transmitting utility to provide service to a retail customer that subsequently becomes, in whole or in part, an unbundled retail transmission services customer of that public utility or transmitting utility.

(6) Retail transmission services means the transmission of electric energy sold, or to be sold, in interstate commerce directly to a retail customer.

(7) New wholesale requirements contract means any wholesale requirements contract executed after July 11, 1994, or extended or renegotiated to be effective after July 11, 1994.

(8) Existing wholesale requirements contract means any wholesale requirements contract executed on or before July 11, 1994.

(c) Recovery of wholesale stranded costs.

(1) General requirement. A public utility or transmitting utility will be allowed to seek recovery of wholesale stranded costs only as follows:

(i) No public utility or transmitting utility may seek recovery of wholesale stranded costs if such recovery is explicitly prohibited by a contract or settlement agreement, or by any power sales or transmission rate schedule or tariff.

(ii) No public utility or transmitting utility may seek recovery of stranded costs associated with a new wholesale requirements contract if such contract does not contain an exit fee or other explicit stranded cost provision.

(iii) If wholesale stranded costs are associated with a new wholesale requirements contract containing an exit fee or other explicit stranded cost provision, and the seller under the contract is a public utility, the public utility may seek recovery of such costs, in accordance with the contract, through rates for electric energy under sections 205-206 of the FPA. The public utility may not seek recovery of such costs through any transmission rate for FPA section 205 or 211 transmission services.

(iv) If wholesale stranded costs are associated with a new wholesale requirements contract, and the seller under the contract is a transmitting utility but not also a public utility, the transmitting utility may not seek an order from the Commission allowing recovery of such costs.

(v) If wholesale stranded costs are associated with an existing wholesale requirements contract, if the seller under such contract is a public utility, and if the contract does not contain an exit fee or other explicit stranded cost provision, the public utility may seek recovery of stranded costs only as follows:

(A) If either party to the contract seeks a stranded cost amendment pursuant to a section 205 or section 206 filing under the FPA made prior to the expiration of the contract, and the Commission accepts or approves an amendment permitting recovery of stranded costs, the public utility may seek recovery of such costs through FPA section 205-206 rates for electric energy.

(B) If the contract is not amended to permit recovery of stranded costs as described in paragraph (c)(1)(v)(A) of this section, the public utility may file a proposal, prior to the expiration of the contract, to recover stranded costs through FPA section 205-206 or section 211-212 rates for wholesale transmission services to the customer.

(vi) If wholesale stranded costs are associated with an existing wholesale requirements contract, if the seller under such contract is a transmitting ***21693** utility but not also a public utility, and if the contract does not contain an exit fee or other explicit stranded cost provision, the transmitting utility may seek recovery of stranded costs through FPA section 211-212 transmission rates.

(vii) If a retail customer becomes a legitimate wholesale transmission customer of a public utility or transmitting utility, e.g., through municipalization, and costs are stranded as a result of the retail-turned-wholesale customer's access to wholesale transmission, the utility may seek recovery of such costs through FPA section 205-206 or section 211-212 rates for wholesale transmission services to that customer.

(2) Evidentiary demonstration for wholesale stranded cost recovery. A public utility or transmitting utility seeking to recover wholesale stranded costs in accordance with paragraphs (c)(1)(v)-(vii) of this section must demonstrate that:

(i) It incurred stranded costs on behalf of its wholesale requirements customer or retail customer based on a reasonable expectation that the utility would continue to serve the customer;

(ii) The stranded costs are not more than the customer would have contributed to the utility had the customer remained a wholesale requirements customer of the utility, or, in the case of a retail-turned-wholesale customer, had the customer remained a retail customer of utility; and

(iii) The stranded costs are derived using the following formula: Stranded Cost Obligation = (Revenue Stream EstimateCompetitive Market Value Estimate)Length of Obligation (reasonable expectation period).

(3) Rebuttable presumption. If a public utility or transmitting utility seeks recovery of wholesale stranded costs associated with an existing wholesale requirements contract, as permitted in paragraph (c)(1) of this section, and the existing wholesale requirements contract contains a notice provision, there will be a rebuttable presumption that the utility had no reasonable expectation of continuing to serve the customer beyond the term of the notice provision.

(4) Procedure for customer to obtain stranded cost estimate. A customer under an existing wholesale requirements contract with a public utility seller may obtain from the seller an estimate of the customer's stranded cost obligation if it were to leave the public utility's generation supply system by filing with the public utility a request for an estimate at any time prior to the termination date specified in its contract.

(i) The public utility must provide a response within 30 days of receiving the request. The response must include:

(A) An estimate of the customer's stranded cost obligation based on the formula in paragraph (c)(2)(iii) of this section;

(B) Supporting detail indicating how each element in the formula was derived;

(C) A detailed rationale justifying the basis for the utility's reasonable expectation of continuing to serve the customer beyond the termination date in the contract;

(D) An estimate of the amount of released capacity and associated energy that would result from the customer's departure; and

(E) The utility's proposal for any contract amendment needed to implement the customer's payment of stranded costs.

(ii) If the customer disagrees with the utility's response, it must respond to the utility within 30 days explaining why it disagrees. If the parties cannot work out a mutually agreeable resolution, they may exercise their rights to Commission resolution under the FPA.

(5) A customer must be given the option to market or broker a portion or all of the capacity and energy associated with any stranded costs claimed by the public utility.

(i) To exercise the option, the customer must so notify the utility in writing no later than 30 days after the public utility files its estimate of stranded costs for the customer with the Commission.

(A) Before marketing or brokering can begin, the utility and customer must execute an agreement identifying, at a minimum, the amount and the price of capacity and associated energy the customer is entitled to schedule, and the duration of the customer's marketing or brokering of such capacity and energy.

(ii) If agreement over marketing or brokering cannot be reached, and the parties seek Commission resolution of disputed issues, upon issuance of a Commission order resolving the disputed issues, the customer may reevaluate its decision in paragraph (c)(5)(i) of this section to exercise the marketing or brokering option. The customer must notify the utility in writing within 30 days of issuance of the Commission's order resolving the disputed issues whether the customer will market or broker a portion or all of the capacity and energy associated with stranded costs allowed by the Commission.

(iii) If a customer undertakes the brokering option, and the customer's brokering efforts fail to produce a buyer within 60 days of the date of the brokering agreement entered into between the customer and the utility, the customer shall relinquish all rights to broker the released capacity and associated energy and will pay stranded costs as determined by the formula in paragraph (c)(2)(iii) of this section.

(d) Recovery of retail stranded costs.

(1) General requirement. A public utility may seek to recover retail stranded costs through rates for retail transmission services only if the state regulatory authority does not have authority under state law to address stranded costs at the time the retail wheeling is required.

(2) Evidentiary demonstration necessary for retail stranded cost recovery. A public utility seeking to recover retail stranded costs in accordance with paragraph (d)(1) of this section must demonstrate that:

(i) It incurred stranded costs on behalf of a retail customer that obtains retail wheeling based on a reasonable expectation that the utility would continue to serve the customer; and

(ii) The stranded costs are not more than the customer would have contributed to the utility had the customer remained a retail customer of the utility.
18 CFR § 35.27

§35.27 Power sales at market-based rates.
(a) Notwithstanding any other requirements, any public utility seeking authorization to engage in sales for resale of electric energy at market-based rates shall not be required to demonstrate any lack of market power in generation with respect to sales from capacity for which construction has commenced on or after July 9, 1996.

(b) Nothing in this part

(1) Shall be construed as preempting or affecting any jurisdiction a state commission or other state authority may have under applicable state and federal law, or

(2) Limits the authority of a state commission in accordance with state and federal law to establish

(i) Competitive procedures for the acquisition of electric energy, including demand-side management, purchased at wholesale, or

(ii) Non-discriminatory fees for the distribution of such electric energy to retail consumers for purposes established in accordance with state law.
18 CFR § 35.28

§35.28 Non-discriminatory open access transmission tariff.
(a) Applicability. This section applies to any public utility that owns, controls or operates facilities used for the transmission of electric energy in ***21694** interstate commerce and to any non-public utility that seeks voluntary compliance with jurisdictional transmission tariff reciprocity conditions.

(b) Definitions.

(1) Requirements service agreement means a contract or rate schedule under which a public utility provides any portion of a customer's bundled wholesale power requirements.

(2) Economy energy coordination agreement means a contract, or service schedule thereunder, that provides for trading of electric energy on an "if, as and when available" basis, but does not require either the seller or the buyer to engage in a particular transaction.

(3) Non-economy energy coordination agreement means any non-requirements service agreement, except an economy energy coordination agreement as defined in paragraph (b)(2) of this section.

(c) Non-discriminatory open access transmission tariffs.

(1) Every public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce must have on file with the Commission a tariff of general applicability for transmission services, including ancillary services, over such facilities. Such tariff must be the open access pro forma tariff contained in Order No. 888, FERC Stats. & Regs. 31,036 (Final Rule on Open Access and Stranded Costs) or such other open access tariff as may be approved by the Commission consistent with Order No. 888, FERC Stats. & Regs. 31,036.

(i) Subject to the exceptions in paragraphs (c)(1)(ii), (c)(1)(iii), and (c)(1)(iv) of this section, the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. 31,036, and accompanying rates, must be filed no later than 60 days prior to the date on which a public utility would engage in a sale of electric energy at wholesale in interstate commerce or in the transmission of electric energy in interstate commerce.

(ii) If a public utility owns, controls or operates facilities used for the transmission of electric energy in interstate commerce as of July 9, 1996, it must file the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. 31,036, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA, no later than July 9, 1996. However, if a public utility has already filed, or has on file, an open access tariff and accompanying rates as of April 24, 1996, it may, but is not required to, file new rates with its section 206 pro forma tariff filing.

(iii) If a public utility owns, controls or operates transmission facilities used for the transmission of electric energy in interstate commerce as of July 9, 1996, such facilities are jointly owned with a non-public utility, and the joint ownership contract prohibits transmission service over the facilities to third parties, the public utility with respect to access over the public utility's share of the jointly owned facilities must file no later than December 31, 1996 the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. 31,036, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA.

(iv) If a public utility obtains a waiver of the tariff requirement pursuant to paragraph (d) of this section, it does not need to file the pro forma tariff required by this section.

(v) Any public utility that seeks a deviation from the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. 31,036, must demonstrate that the deviation is consistent with the principles of Order No. 888, FERC Stats. & Regs. 31,036.

(2) Every public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce, and that uses those facilities to engage in wholesale sales and/or purchases of electric energy, or unbundled retail sales of electric energy, must take transmission service for such sales and/or purchases under the open access tariff filed pursuant to this section.

(i) Subject to the exceptions in paragraphs (c)(2)(ii) and (c)(3)(iv) of this section, this requirement is effective on the date that such public utility engages in a wholesale sale or purchase of electric energy or any unbundled retail sale of electric energy, but no earlier than July 9, 1996.

(ii) For sales of electric energy pursuant to a requirements service agreement executed on or before July 9, 1996, this requirement will not apply unless separately ordered by the Commission. For sales of electric energy pursuant to a bilateral economy energy coordination agreement executed on or before July 9, 1996, this requirement is effective on December 31, 1996. For sales of electric energy pursuant to a bilateral non-economy energy coordination agreement executed on or before July 9, 1996, this requirement will not apply unless separately ordered by the Commission.

(3) Every public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce, and that is a member of a power pool, public utility holding company, or other multi-lateral trading arrangement or agreement that contains transmission rates, terms or conditions, must file a joint pool-wide or system-wide open access transmission pro forma tariff.

(i) For any power pool, public utility holding company or other multi-lateral arrangement or agreement that contains transmission rates, terms or conditions and that is executed after July 9, 1996, this requirement is effective on the date that transactions begin under the arrangement or agreement.

(ii) For any public utility holding company arrangement or agreement that contains transmission rates, terms or conditions and that is executed on or before July 9, 1996, this requirement is effective July 9, 1996, except for the Central and South West System, which must comply no later than December 31, 1996.

(iii) For any power pool or multi-lateral arrangement or agreement other than a public utility holding company arrangement or agreement, that contains transmission rates, terms or conditions and that is executed prior to July 9, 1996, this requirement is effective on December 31, 1996.

(iv) A public utility member of a power pool, public utility holding company or other multi-lateral arrangement or agreement that contains transmission rates, terms or conditions and that is executed on or before July 9, 1996 must begin to take service under a joint pool-wide or system-wide pro forma tariff for wholesale trades among the pool or system members no later than December 31, 1996.

(d) Waivers. A public utility subject to the requirements of this section and Order No. 889, FERC Stats. & Regs. 31,037 (Final Rule on Open Access Same-Time Information System and Standards of Conduct) may file a request for waiver of all or part of the requirements of this section, or Part 37 (Open Access Same-Time Information System and Standards of Conduct for Public Utilities), for good cause shown. An application for waiver must be filed either:

(i) No later than July 9, 1996 or

(ii) No later than 60 days prior to the time the public utility would otherwise have to comply with the requirement.

(e) Non-public utility procedures for tariff reciprocity compliance.

(1) A non-public utility may submit a transmission tariff and a request for declaratory order that its voluntary transmission tariff meets the requirements of Order No. 888 (Final Rule on Open Access and Stranded Costs).

***21695** (i) Any submittal and request for declaratory order submitted by a non-public utility will be provided an NJ (non-jurisdictional) docket designation.

(ii) If the submittal is found to be an acceptable transmission tariff, an applicant in a Federal Power Act (FPA) section 211 case against the non-public utility shall have the burden of proof to show why service under the open access tariff is not sufficient and why a section 211 order should be granted.

(2) A non-public utility may file a request for waiver of all or part of the reciprocity conditions contained in a public utility open access tariff, for good cause shown. An application for waiver may be filed at any time.

PART 385—RULES OF PRACTICE AND PROCEDURE

1. The authority citation for part 385 continues to read as follows:

Authority: 5 U.S.C. 551-557; 15 U.S.C. 717-717z, 3301-3432; 16 U.S.C. 791a-825r, 2601-2645; 31 U.S.C. 9701; 42 U.S.C. 7101-7352; 49 U.S.C. 60502; 49 App. U.S.C. 1-85.

18 CFR § 385.2011

2. Part 385 is amended by adding paragraph (b)(5) to §385.2011 to read as follows:

18 CFR § 385.2011

§385.2011 Procedures for filing on electronic media (Rule 2011).

* * * * *

(b) * * *

(5) Non-discriminatory open access transmission tariffs filed pursuant to § 35.28 of this chapter.

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Note: Appendices A through H and statements of Commissioners Hoecker and Massey will not be published in the Code of Federal Regulations.

List of Section 211 Applications

No.	Docket No.	Applicant	Transmitter	Commission action
1	TX93-1-000	Tex-La Electric Cooperative of Texas, Inc	Texas Utilities Electric Company	Denied, 64 FERC 61,162
2	TX93-2-000	City of Bedford, Virginia, et al	American Electric Power Company, Inc	Granted Final order, 68 FERC 61,003 Reh'g denied, 73 FERC 61,322
3	TX93-3-000	Wisconsin Electric Power Company	Upper Peninsula Power Company	Withdrawn 9/10/93
4	TX93-4-000	Florida Municipal Power Agency	Florida Power & Light Company	Granted Final order, 67 FERC 61,167 Order on reh'g, 74 FERC 61,006
5	TX94-1-000	Minnesota Municipal Power Agency	Northern States Power Company	Granted Proposed order, 66 FERC 61,114 Reh'g denied, 66 FERC 61,323 Settlement accepted by letter order, 68 FERC 61,031
6	TX94-2-000	El Paso Electric Company, et al	Southwestern Public Service Company	Proposed order, 68 FERC 61,182, order on reh'g, 68 FERC 61,399, order dismiss'g proceeding, 72 FERC 61,292
7	TX94-3-000	Minnesota Municipal Power Agency	Southern Minnesota Municipal Power Agency	Granted Proposed order, 66 FERC 61,223, reh'g denied, 67 FERC 61,075, Final order, 68 FERC 61,060
8	TX94-4-000	Tex-La Electric Cooperative of Texas, Inc	Texas Utilities Electric Company	Granted Proposed order, 67 FERC 61,019, Final order, 69 FERC 61,269

9	TX94-5-000	Old Dominion Electric Cooperative, Inc	Delmarva Power & Light Company	Granted Proposed order, 68 FERC 61,169 Settl'd, 69 FERC 61,436, 70 FERC 61,082
10	TX94-6-000	Reading Municipal Light Department	16 New England Transmitting Utilities	Terminated July 10, 1995 by OEPR Letter Order, following notice of withdrawal filed May 8, 1995
11	TX94-7-000	AES Power, Inc	Tennessee Valley Authority	Granted Final Order issued Feb 29, 1996, 74 FERC 61,220, reh'g pending
12	TX94-8-000	Duquesne Light Company	PJM Companies	Granted Proposed order issued 5/16/95, 71 FERC 61,155
13	TX94-9-000	Borough of Zelienople, Pennsylvania	Pennsylvania Power Company	Granted Proposed order issued 1/25/95, 70 FERC 61,073
14	TX94-10-000	Duquesne Light Company	Allegheny Power System	Granted Proposed order issued 5/16/95, 71 FERC 61,156
15	TX95-1-000	Enron Power Marketing, Inc	Consolidated Edison Co of New York	Pending Comments due 11/3/94
16	TX95-2-000	Wisconsin Public Power Inc SYSTEM	WEPCO, WP&L, WPSC	Pending Comments due 11/16/94
17	TX95-3-000	Municipal Energy Agency of Nebraska	Nebraska Public Power District and Tri-State Generation and Transmission Association, Inc	w/drawn 11-16-95
18	TX95-4-000	American Municipal Power-Ohio, Inc	Ohio Edison Company	Granted Proposed Order issued Feb 1, 1996 74 FERC 61,086
19	TX95-5-000	United States Department of Energy—Southeastern Power Administration	Southern Company System	Pending
20	TX95-6-000	Cleveland Public Power	Centerior Energy Corporation	Rejected Without Prejudice 72 FERC 61,189
21	TX95-7-000	Cleveland Public Power	Cleveland Electric Illuminating Company and Toledo Edison Company	Pending
22	TX96-1-000	Citizens Utilities Company	Swanton Village, Vermont	Pending
23	TX96-2-000	City of College Station, Texas	City of Bryan, Texas and Texas Municipal Power Agency	Pending
24	TX96-3-000	Citizens Utilities Company	Swanton Village, Vermont	Pending
25	TX96-4-000	Suffolk County Electrical Agency	Long Island Lighting Company	Pending
26	TX96-5-000	United States Department of Energy—Western Area Power Administration	Public Service Company of New Mexico	Pending
27	TX96-6-000	Montana Power Company	Basin Electric Cooperative	Pending
28	TX96-7-000	City of Palm Springs, California	Southern California Edison Company	Pending

Appendix B—List of Commenters

Abbreviation	Commenter
1. ABATE	Association of Businesses Advocating Tariff Equity.
2. AEC & SMEPA	Alabama Electric Cooperative, Inc. and South Mississippi Electric Power Association.
3. AEP	American Electric Power System.
4. AGA	American Gas Association.
5. Air Liquide	Air Liquide America Corporation.
6. AL Com	Alabama Public Service Commission.
7. ALCOA	Aluminum Company of America.
8. Allegheny	Allegheny Power Service Corporation.
9. Alma	City of Alma, Michigan.
10. Aluminum	Aluminum Association.
11. American Forest & Paper	American Forest & Paper Association.
12. American Iron & Steel	American Iron & Steel Institute American Forest & Paper Association, American Public Power Association, Chemical Manufacturers Association, Citizen Action, Council of Industrial Boiler Owners, Electricity Consumers Resource Council, Environmental Action Foundation, City of Las Cruces, New Mexico, City of Westbrook, Maine, Sovereign California Cities Joint Powers Committee, Toward Utility Rate Normalization.
13. American National Power	American National Power, Inc.
14. American Wind	American Wind Energy Association.
15. AMP-Ohio	American Municipal Power-Ohio, Inc. and Indiana Municipal Power Agency.
16. Anaheim	Cities of Anaheim, Azusa, Banning, Colton and Riverside, California.
17. Anchorage	Anchorage Municipal Light and Power.
18. Anoka EC	Anoka Electric Cooperative.
19. APPA	American Public Power Association.
20. APS Customers	APS Wholesale Customer Group (Aquila Irrigation District, Buckeye Water Conservation District, Electrical District No. 3 of Pinal County, Electrical District No. 6 of Pinal County, Electrical District No. 7 of Maricopa County, Electrical District No. 8 of Maricopa County, Harquahala Valley Power District, Maricopa County Municipal Water Conservation District No. 1, McMullan Valley Water

	Conservation District, Roosevelt Irrigation District and Tonopah Irrigation District).
21. Arcadia	Arcadia Resources, Inc.
22. Arizona	Arizona Public Service Company.
23. Arizona EC	Arizona Electric Power Cooperative.
24. Ark Elec	Arkansas Electric Cooperative Corporation.
25. Arkansas Cities	Arkansas Cities and Farmers Electric Cooperative.
26. Associated EC	Associated Electric Cooperative, Inc.
27. Associated Power	Associated Power Services, Inc.
28. Atlantic City	Atlantic City Electric Company.
29. AZ Com	Arizona Corporation Commission.
30. Baker EC	Baker Electric Cooperative, Inc.
31. Baltimore Transp Bureau	Transportation Bureau of Baltimore, Inc.
32. Basin EC	Basin Electric Power Cooperative.
33. BG&E	Baltimore Gas and Electric Company.
34. Big Horn REC	Big Horn Rural Electric Company.
35. Big Rivers EC	Big Rivers Electric Cooperative.
36. Black Hills EC	Black Hills Electric Cooperative.
37. Black Mayors	National Conference of Black Mayors.
38. Blue Ridge	Blue Ridge Power Agency, Northeast Texas Electric Cooperative, Inc., Sam Rayburn G&T Electric Cooperative, Inc., and Tex-La Electric Cooperative of Texas, Inc.
39. Bon Homme Yankton EC	Bon Homme Yankton Electric Association, Inc.
40. Boston Edison	Boston Edison Company.
41. Boulder	City of Boulder, Colorado.
42. BPA	Bonneville Power Administration.
43. Brazos	Brazos Electric Power Cooperative, Inc.
44. Brownsville	Brownsville, Texas Public Utilities Board.
45. Building Owners	Building Owners and Managers Association International.
46. CA Cogen	Cogeneration Association of California.
47. CA Com	California Public Utilities Commission.

48. CA Energy Co	California Energy Company, Inc.
49. CA Energy Com	California Energy Commission.
50. Cajun	Cajun Electric Power Cooperative, Inc.
51. California DWR	California Department of Water Resources.
52. California Water Agencies	Association of California Water Agencies.
53. Calpine	Calpine Corporation.
54. CAMU	Colorado Association of Municipal Utilities.
55. Canada	Canadian Embassy.
56. Canadian Petroleum Producers	Canadian Association of Petroleum Producers.
57. Caparo	Caparo Steel.
58. Carbon Power	Carbon Power & Light Inc.
59. Carolina P&L	Carolina Power & Light Company.
60. CCEM	Coalition for a Competitive Electric Market (consisting of Catex Vitol Electric, Inc., Coastal Electric Services Company, Destec Power Services, Inc., Electric Clearinghouse, Inc., Enron Power Marketing, Inc., Equitable Power Services Company, KCS Power Marketing, Inc. and MidCon Power Services Corp.).
61. Centerior	Centerior Energy Corporation.
62. Central EC	Central Electric Power Cooperative.
63. Central Hudson	Central Hudson Gas & Electric Corporation.
64. Central Illinois Light	Central Illinois Light Company.
65. Central Illinois Public Service	Central Illinois Public Service Company.
66. Central Louisiana	Central Louisiana Electric Company, Inc.
67. Central Montana EC	Central Montana Electric Power Cooperative, Inc.
68. Christensen	Laurits R. Christensen Associates Inc.
69. Chugach	Chugach Electric Association, Inc.
70. CINergy	CINergy Corp.
71. Citizens Lehman	Citizens Lehman Power L.P.
72. Citizens Utilities	Citizens Utilities Company.
73. Clark	Clark Public Utilities.

74. Clean Air	Clean Air Action Corporation.
75. Cleveland	Cleveland Public Power.
76. CO Com	Colorado Public Utilities Commission Staff.
77. CO Consumers Counsel	Colorado Office of Consumer Counsel.
78. Coalition for Economic Competition	Coalition for Economic Competition (consisting of Central Hudson Gas & Electric Corporation, Central Maine Power Company, Consolidated Edison Company of New York, Inc., Illinois Power Company, Long Island Lighting Company, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation.
79. Coalition on Federal-State Issues	Coalition on Federal-State Issues of the Power Marketing Association.
80. Com Ed	Commonwealth Edison Company.
81. Com Electric	Commonwealth Electric Company.
82. Competitive Enterprise	Competitive Enterprise Institute.
83. Concord	Concord Municipal Light Plant.
84. ConEd	Consolidated Edison Company of New York, Inc.
85. Conservation Law Foundation	Conservation Law Foundation and Center for Efficiency and Renewable Technologies.
86. Consolidated Natural Gas	Consolidated Natural Gas Company.
87. Consumers Power	Consumers Power Company.
88. Continental Power Exchange	Continental Power Exchange, Inc.
89. Cooperative Power	Cooperative Power.
90. CSW	Central and South West Corporation.
91. CT DPUC	Connecticut Department of Public Utility Control.
92. CT Munis	Connecticut Conference of Municipalities.
93. CVPSC	Central Vermont Public Service Corporation.
94. Dairyland	Dairyland Power Cooperative.
95. Dayton P&L	Dayton Power and Light Company.
96. DC Com	Public Service Commission of the District of Columbia.
97. DE Muni	Delaware Municipal Electric Corporation, Inc.