In response to APPA's objection that the Commission has failed to establish the showing that it would require to overcome the presumption, we note that the Commission cannot establish such a showing upfront because whether there is sufficient evidence to rebut the presumption of no reasonable expectation will depend on the facts of each case.

We appreciate the concerns expressed by some entities that the rebuttable presumption may increase the customer's uncertainty by inviting litigation. We have carefully weighed the pros and cons of treating a notice provision as a rebuttable presumption of no reasonable expectation versus the pros and cons of treating it as a conclusive presumption of no reasonable expectation. It is true, as some entities assert, that the rebuttable presumption approach presents the potential for litigation between the parties as to whether, in a particular case, the utility can rebut the presumption. The alternative would be to treat all contracts with notice of termination provisions as conclusive evidence that the utility could have had no reasonable expectation that it would continue to serve the customer beyond the specified notice period. While the latter approach presumably would reduce the number of cases in which the issue of a utility's reasonable expectation would have to be litigated, it would do so only by prohibiting a utility from ever demonstrating that, notwithstanding the existence of a notice provision, based on the facts of a particular case, the utility reasonably expected to continue serving the customer. While we do not prejudge the likelihood of a utility being able to rebut the presumption in a particular case, we believe that it would not be in the public interest for the Commission to absolutely preclude a utility from being able to make such a showing. On this basis, we conclude that treating a notice provision as a rebuttable, rather than a conclusive, presumption that the utility did not have a reasonable expectation of continuing service to the customer is, on balance, the fairer and more equitable approach.

Central Montana EC asserts that it is wrong to infer from the existence of an automatic renewal provision that the parties intended that the contract might run longer than its initial term. However, our statement in Order No. 888 that the existence of an 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 makes no such inference. Whether the utility can rebut the presumption will depend on the facts of each case.

Rehearing Requests Supporting Modification of Evidentiary Standard for Retail Customers

Several entities ask the Commission to consider adopting a rebuttable presumption that utilities had a reasonable expectation of continuing to serve any retail load for which they had a public utility obligation to serve. They submit that the burden should be on the former bundled retail customer to show that the utility's service obligation was not binding and that the utility's expectation of continuing service was unfounded.[FN736] Florida Power Corp and Utilities For Improved Transition suggest that the only exception to such a rebuttable presumption should be for retail customers that gave notice of termination before the effective date of the Rule. EEI expresses concern that the issue may be wrongly decided on the existence (or lack) of an exclusive franchise. It states that while many states do award franchises delineating exclusive service territories, some do not, even though long-established service arrangements are in place. Puget submits that because there is a duty to serve all retail customers, Order No. 888 should provide for stranded cost recovery from all departing retail customers without application of a reasonable expectation test.

NY Com, on the other hand, opposes application of the reasonable expectation standard to stranded costs associated with retail-turned-wholesale customers. It argues that the reasonable expectation test would ignore prudence, customer impact, financial viability and a series of criteria traditionally analyzed by state regulatory agencies in determining rate treatment of costs incurred with the intention of providing service.

Commission Conclusion

We will deny the requests for rehearing of the Commission's decision to apply the reasonable expectation standard to retail-turned-wholesale and retail wheeling customers on a case-by-case basis without adopting a rebuttable presumption that utilities had a reasonable expectation of continuing to serve any retail load for which they had a public utility obligation to serve. When a utility seeks to recover stranded costs from former bundled retail customers, we think it is appropriate that the utility bear the burden of proving reasonable expectation (instead of requiring the customer to bear the burden of disproving the utility's reasonable expectation). Placing the burden on the utility is consistent with the requirement of sections 205 and 206 of the FPA that a public utility demonstrate the justness and reasonableness of its proposed rates. The same factors that are offered as support for the establishment of a rebuttable presumption of a reasonable expectation (such as the utility's obligation to serve all retail customers) may be offered by the utility as evidence to be considered in determining whether the reasonable expectation test is met in a particular case.

We also will deny NY Com's request that the Commission not apply the reasonable expectation standard to retail-turned-wholesale customers. We believe it is appropriate to require the same evidentiary demonstration for recovery of stranded costs from a retail-turned-wholesale customer as that required in the case of a wholesale requirements customer. Moreover, as discussed in Section IV.J.7 above, the reasonable expectation standard contemplates evidence as to what a utility might reasonably expect to recover under state law, and we will give great weight to a state's view of what might be recoverable.

9. Calculation of Recoverable Stranded Costs

In Order No. 888, the Commission considered various proposals regarding how stranded costs should be calculated and who should pay. With respect to the calculation of stranded costs, the Commission rejected as overly complicated and costly an asset-by-asset ***12418** approach to determine the amount of stranded costs assigned to a departing customer. Instead, the Commission determined that the revenues lost approach was the fairest and most efficient way to make this determination during the transition to a competitive wholesale bulk power market. The Commission adopted the following revenues lost formula for calculating the stranded cost for each departing customer: SCO-(RSE—CMVE) xL. The Commission provided a precise definition for each component of the formula,[FN737] and made the application of the formula, and collection of the resulting stranded costs, subject to a number of conditions.[FN738]

RSE Issues

Numerous petitioners oppose the use of present revenues in the stranded cost formula.[FN739] TDU Systems argues that the revenues lost approach is arbitrary and capricious because its effect exceeds its purpose. Specifically, TDU Systems contends that the revenues lost approach can permit overrecovery because it provides recovery of any difference between pre-Order No. 888 cost-plus rates and post-Order No. 888 competitive rates, regardless of the cause of the difference. TDU Systems cites enhanced utilization and technological improvements as two examples of pre-and post-Order No. 888 rate differences that are not competition related, but for which recovery would be provided. TDU Systems states that instead of using present revenues, RSE should be calculated based on the most current, reliable estimate of future revenues.

Multiple Intervenors argues that the revenues lost method assumes that a utility's costs of operating its plants are per se reasonable, yet the New York utilities' current rates include levels of O&M, especially wages and benefits, expenses that may reflect inefficiencies and thus are not stranded costs for which a utility's shareholders should be compensated. Similarly, other petitioners oppose as backward-looking the use of present revenues for what should be a forward-looking remedy, consistent with the other elements in the formula.[FN740] TDU Systems argues that the use of past revenues is inappropriate in a falling cost environment, and notes that new capacity costs are less than the existing capacity costs embedded in a utility's rate base.

NYSEG states that the Commission should permit a utility to reconcile initial stranded cost charges to actual stranded costs on a periodic basis to account for changes in sales, energy purchases from NUGs, and changes in market price. NYSEG supports development of stranded cost charges based on three-year estimates. Under this approach, a customer would pay locked-in charges for a series of three-year periods. At the end of each period, the stranded cost estimate would be revised for the next three-year period. This process would continue until all stranded costs are recovered.[FN741] Other petitioners support the use of a projected revenue stream or a true-up mechanism.[FN742] These petitioners argue that a true-up mechanism is necessary to protect all parties against the inevitable risk of inaccurate forecasts.

ELCON argues that calculating RSE based upon customer usage over the past three years results in an artificially high stranded cost because it fails to take into account that the utility would have had to reduce its prices in the future in response to competition.

ELCON states that wholesale customers have a reasonable expectation that utility costs will be lower in the future, and thus that the annual revenues contributed by a customer who remains with the utility would be lower than RSE. ELCON further contends that the revenues lost formula should not guarantee the profits the utility was allowed to receive prior to the issuance of Order No. 888 because such revenues included a risk factor (e.g., plant operating risk, or risk of customer insolvency) that is absent under the direct assignment method of allocating stranded costs. ELCON cites Town of Norwood v. FERC[FN743] as support for its position that the RSE should be reduced to reflect the decreased risk associated with the direct assignment approach.

TDU Systems and NRECA also argue that the Commission should eliminate from RSE the risk component of the return on equity contained in present rates. They argue for this adjustment because the Commission is eliminating the risk associated with non-recovery of plant costs by providing full recovery of stranded costs. NRECA further contends that if the Commission keeps the equity return in the calculation of stranded costs, it should permit a consumer-owned system to include an imputed equity component in its RSE if it needs to recover stranded costs.

APPA argues that the use of present revenues fails to reflect future cost reductions expected from accumulated depreciation, load growth, and declining capital costs. APPA further opposes the use of present revenues because present revenues are the direct product of the monopoly power that the utility exercised over transmission. APPA states that RSE should be calculated based upon the price of wholesale power in a competitive market.

CCEM argues that only fixed costs should be eligible for recovery, and that this amount should exclude any return on investment. CCEM would exclude variable costs from the calculation of stranded costs because allowing recovery of variable charges would encourage the continued operation of facilities that are conceded to be uneconomic. CCEM further contends that the Commission should provide less than full recovery of stranded costs so that the utility has some incentive to mitigate them.

Central Vermont states that where the contract does not commit the customer to a set amount of service, the utility's reasonable expectation of the amount of continuing service will not necessarily be reflected in the revenues of the three previous years. Central Vermont urges the Commission to allow utilities the option of showing that their actual reasonable expectation of continued service differs from historical experience. Central Vermont maintains that any other approach would be less than reasonable, and, in fact, would be arbitrary and capricious.

Numerous petitioners[FN744] would retain the use of present revenues as the RSE; however, they support a limited exception that would permit a utility to seek recovery of certain future cost increases (primarily nuclear decommissioning costs, back-loaded PURPA contract costs, and other deferred costs) if those costs are not in rates now or are in rates but are being under-recovered at present. These ***12419** petitioners argue that the majority of these costs were incurred as a result of various regulatory mandates, with the reasonable expectation of future recovery in rates. As a part of their proposal, Utilities For Improved Transition and EEI (and others) support offsetting such cost increases with any decreases in other costs reflected in present revenues. Utilities For Improved Transition maintains that nuclear decommissioning costs, in particular, should be revisited as they become better defined. Similarly, Nuclear Energy Institute and others request that the Commission allow a utility, on a case-by-case basis, to propose its own recovery mechanism, as nuclear decommissioning costs are significantly different from other future cost increases.

Lastly, TDU Systems and NRECA object to the manner by which the formula deducts average transmission-related revenues (which would be unbundled in the utility's new open access tariff) in the development of RSE. TDU Systems and NRECA contend that the transmission credit, because it is based on the revenues that would be generated under a utility's new wholesale tariff, would not reflect that the cost of transmission has been declining.

Commission Conclusion

In Order No. 888, the Commission stated that the use of "present" annual revenues as the basis for the stranded cost calculation has numerous advantages over other approaches advocated. The Commission noted that the use of present revenues (1) eliminates disputes over estimates of future revenues, providing certainty to the calculation; and (2) eliminates the need for a detailed listing and litigation of includable costs, relying instead on the presumption that present rates include all just and reasonable costs of providing service. The Commission further noted that 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.

The Commission continues to believe that the use of present revenues as the basis for the stranded cost calculation is superior to other proposed methods. Arguments that the use of present revenues either over-or under-recovers "true" costs are not persuasive. Either the customer or the utility may file for a change in rates before the existing contract ends if it believes the existing rate is inappropriate.

In response to petitioners requesting an RSE based on estimates of future revenues for the reasonable expectation period (L), we continue to believe that an approach based on estimates of future revenue streams would engender countless disputes over the RSE component in the formula with little, if any, added accuracy. These would in effect be rate cases that attempt to litigate not what costs were during a test year based on audited accounting data, but what costs will be, based on speculation about future fuel costs, employment levels, capital costs, and so on. In contrast, we believe that the use of present revenues will produce fair results and minimize litigation of RSE. This is appropriate for a transition period cost recovery charge that needs to be settled quickly for market participants to make business decisions about future wholesale sales and purchases. Our approach minimizes transaction costs and provides greater certainty with respect to the RSE term in the formula.

Some have argued that a method that periodically adjusts the departing customer's stranded cost obligation in the future to reflect actual future increases or decreases in a utility's future cost-based rates would produce more accurate results. However, this "true-up" approach has several difficulties. First, it assumes that the utility will have wholesale cost-based rates in the future. Many utilities already sell in the wholesale market at market-based rates, and this trend is accelerating. Having a series of ongoing rate cases solely for the purpose of trueing-up a stranded cost calculation would be cumbersome and costly. It would eliminate much of the regulatory cost savings that result from market-based rates. Further, even if "cost-based" rates were on file in the future, many such future wholesale rates, as in the past, are likely to result from settlements among the parties. Such settlements are agreements on prices that do not necessarily spell out the cost components of the final agreed-upon rate.

These difficulties aside, the true-up approach would introduce a great deal of ongoing uncertainty about the departing customer's stranded cost obligation. This uncertainty would add unnecessary risk for both the customer and the utility as they consider alternative purchase or sales transactions. Customers would have no way of knowing what their ultimate stranded cost charge would be, and therefore would be unable to evaluate definitively whether changing suppliers would be beneficial. Under a true-up approach, the eventual sum of the customer's SCO and replacement power cost could be more or less than the amount it would have paid had it simply stayed with its host supplier. This possibility could discourage many customers from taking advantage of the open access provided by Order No. 888. We believe that any potential accuracy benefit of a true-up approach is greatly outweighed by the cost, uncertainty, delay, and litigation such an approach would cause.

In summary, we believe that the use of present revenues as the basis for calculating stranded cost appropriately balances precision and efficiency[FN745] for what is fundamentally a transition period policy.

In response to the other arguments raised, the Commission makes the following findings. We disagree with ELCON that the use of present revenues will result in an artificially high stranded cost because it fails to account for the fact that a utility would have to lower its prices to respond to new competition. ELCON's argument is circular in that much of the new competition to which it refers results from our issuance of Order No. 888. ELCON's approach would undo the goal of providing recovery of stranded costs by eliminating the very difference that the formula is intended to determine. [FN746] ELCON's argument is rejected accordingly.

In addition, ELCON's reliance on Town of Norwood (for the proposition that RSE should be reduced to reflect the reduced operating risk and reduced risk of customer insolvency associated with direct assignment of stranded costs) is misplaced. In Town of Norwood, the Commission was faced with a request for recovery of plant costs. The utility made a cost-effective proposal to shut down its single asset, a small nuclear reactor. In that case, the Commission disallowed full return on investment in part because the unit was no longer operating and the utility had no operating risk.

Elimination of the rate of return is inappropriate because, unlike Town of Norwood, the departing customer's service is not tied to any particular unit; rather, service is considered to be provided by the entire system. Contrary to ELCON's assertion, operating risk is not reduced because the utility must continue to operate its generating facilities (by reselling the capacity) if it is to recover all its costs. Accordingly, ***12420** there is not a reduced operating risk as argued by ELCON.

With respect to ELCON's customer insolvency argument, this risk is also present under the direct assignment approach. Because Order No. 888 permits a customer to pay its stranded cost obligation over a number of years, during this period the customer could become insolvent, thereby leaving the utility with uncollected stranded costs.[FN747]

Also, unlike Town of Norwood, the utility is presently collecting rates that compensate for traditional utility risks, but do not include the risk of open access. Further, eliminating the rate of return would engender considerable complication, speculation and expense as the Commission would have to determine an appropriate rate of return that included some risks (e.g., customer bankruptcy) but not others (e.g., 211 request or use of the open access tariff). Thus, eliminating the rate of return (or a portion thereof) is inappropriate.

Accordingly, ELCON's arguments that the revenue stream should be reduced to reflect lower risk associated with direct assignment is rejected. Instead, we continue to believe that the transmission provider is entitled to recover all the costs, including return on equity, that it incurred based on a reasonable expectation of having to serve the departing customer. All these costs would have been recoverable absent the action taken in Order No. 888.[FN748]

The Commission also rejects NRECA's proposal to include an imputed equity component in the RSE when calculating stranded costs for a consumer-owned system. Simply put, if a cost is not stranded, or if a cost is not really a cost, recovery should not be granted.

The Commission rejects APPA's contention that it is inappropriate to use present revenues as the RSE because those revenues are the direct product of the monopoly power that the utility exercised over transmission. The Commission believes that the use of present revenues is one of the strengths of the formula in that the rates that produce present revenues have been approved by regulators as just and reasonable, which strongly suggests that the costs included in them have been shown to be prudent, legitimate and verifiable.

In response to CCEM's argument that only fixed costs should be eligible for recovery (because the inclusion of variable costs in the RSE will encourage the continued operation of facilities that are conceded to be uneconomic), we agree. The Commission notes that condition 1, “Cap on SCO” [FN749] limits the recovery of stranded costs to fixed costs. Accordingly, the formula, as designed, addresses CCEM's concern.

We note that Central Vermont supports its opposition to the use of present revenues differently from other petitioners, who argue (in effect) that the price component of RSE is flawed.[FN750] Central Vermont, on the other hand, is concerned that the quantity component of present revenues may not reflect the quantity that would have been taken during L. It states that the Commission should permit the utility to show that it had a reasonable expectation of continued customer service that is not based on the customer's previous three years of power consumption. The Commission does not believe that this is appropriate. Central Vermont's approach would introduce forecasting controversy, litigation cost, and uncertainty which are similar to the disputes about cost discussed above. For example, a utility might argue that the customer was expected to consume more than it has in the last three years, based presumably on such factors as expected economic development, changing demographics, appliance saturation rates, and even changes in climate. Conversely, the departing customer might argue that it would have increased electricity conservation efforts, used more natural gas, relied more on self-generation, and so on, if open access had not been made available by Order No. 888. The Commission has stated above why it favors the use of present revenues, for both price and quantity combined, and these reasons apply regardless of whether the argument is directed toward the price or quantity component of present revenues.

Finally, TDU Systems' and NRECA's argument regarding the transmission revenue credit component of RSE is made on the same basis as their argument that the revenue stream should be calculated on a forward-looking basis. For the reasons discussed above, we reject this argument also.

Therefore, after consideration of the arguments on rehearing, and reconsideration of our policy rationale supporting the use of present revenues, we continue to support the use of present revenues, without true-ups or adders, as the basis for the stranded cost formula. We find that the use of present revenues fairly and efficiently balances the competing interests of the affected parties.

CMVE Issues

Petitioners raised a number of CMVE related issues. We take them up in the following two categories.

Present Value Issues

EEI agrees with the Commission that stranded costs should be calculated on a present value basis. EEI states that with respect to RSE, the formula appears to be stated on a present value basis, although it believes that the language could be strengthened to read: "the present value of average annual revenues from the departing customer over the three years prior * * *" (new text emphasized).

However, EEI maintains that the rule fails to define CMVE clearly on a present value basis. Therefore, EEI suggests that the Commission clarify the definition as follows: "Option 1—the utility's estimate of the net present value of the average annual revenues * * * or Option 2—the net present value of the average annual cost to the customer of replacement capacity and associated energy * * *" (new text underlined). EEI states that this clarification could also be applied to the "Cap on SCO," to put it on a par with the other definitions in terms of the time value component.

TDU Systems and NRECA also express concerns regarding the calculation of SCO on a present value basis. Specifically, they state that the formula contains no component, factor, or other mechanism to indicate how such present value is to be determined. They also state that no discount rate is specified, and that the calculation should be synchronized with the customer's chosen payment option. Central Vermont maintains that the Commission should make it clear that a utility is entitled to recovery of both ***12421** stranded costs and the time value of those costs from the date on which they were experienced through the date of their recovery.

Commission Conclusion

We believe that EEI misinterprets our intent with the three-year average annual revenues for RSE. EEI is proposing to increase the revenues of three years ago to current dollars, the revenues of two years ago to current dollars (and so on) before finding the three-year average. The Commission clarifies that our use of the term "present value" does not require such an adjustment. If the utility thought its rates on file did not adequately reflect rising costs, it should have filed for a rate increase. If it did file for and receive a rate increase, the formula does not use a three-year average, but rather revenue based on the new rate.[FN751] It would be inappropriate to adjust the three years of revenue used to calculate RSE to a current dollar value if these rates have been in effect for three years without change. It is assumed that all costs, including inflationary and deflationary changes in the underlying costs, have been recovered. We do not have any time lag between the provision of service and the recovery of the costs of providing that service. Accordingly, EEI's proposed present value adjustment is neither necessary nor appropriate.

With respect to EEI's concern that CMVE is not determined on a present value basis, we clarify that it should be calculated on a present value basis. Both the revenues that would have been collected if the customer had remained on the system and the revenues the utility expects to collect by selling the power must be stated on a present value basis so that the difference, RSE-CMVE, is at present value.[FN752] The "Cap on SCO" must also be stated on a present value basis.

In response to TDU Systems, NRECA and Central Vermont, we clarify that a utility is entitled to recovery of stranded costs and the time-value of the revenues that would have been recovered.[FN753] However, we decline to specify the discount rate or the number of periods to be used in the calculation. Although establishing a uniform discount rate would serve to minimize disputes over the calculation, we prefer to give the parties some flexibility on the use of a discount rate. Similarly, we do not prescribe the number of periods to be used in the present value calculation as this also should be determined on a case-by-case basis due to differences in "L" and billing payment cycles for each departing customer.

CMVE Option 2 Issues

In Order No. 888, the Commission allows the departing customer to set CMVE equal to the average annual revenues it would pay to its alternative supplier. This option is referred to as CMVE Option 2.

SoCal Edison and Central Vermont argue that CMVE Option 2 should be eliminated because it will be administratively difficult to monitor and enforce. In their view, Option 2 will allow customers the opportunity to "game" the system, which will increase the utility's and the Commission's administrative costs and place the utility at risk for less than full recovery of stranded costs. In addition, SoCal Edison maintains that it will be difficult to reflect in the calculation of stranded costs any non-price benefits a customer may receive under the contract. SoCal Edison further maintains that there is a possibility that additional bargains may have been struck outside of the agreement between the new supplier and the departing customer. These bargains may have the effect of increasing the price of the alternative power, but the terms of the bargains would not be known to the utility to use in adjusting CMVE. As a result, the customer's contract price may not accurately reflect the utility's CMVE, resulting in an inaccurate estimate of stranded cost responsibility.

EEI has requested that the Commission clarify that the conditions placed on CMVE Option 2 were intended to prevent the customer from unfairly avoiding its full stranded cost obligation (i.e., prevent gaming of the stranded cost calculation). EEI also states that the Commission should give the utility an opportunity to challenge the validity of the replacement contract's price, terms and conditions on a case-by-case basis or give the utility the right of first refusal to provide power to the customer under the replacement contract's price, terms and conditions. Carolina P&L requests that the Commission require the departing customer to make a compliance filing containing information regarding the replacement contract. Centerior maintains that in order to guard against the customer overpaying for replacement capacity (thereby lowering its SCO), the Commission should use the revenues received by the host utility in the resale of the power to determine the CMVE.

NRECA and TDU Systems maintain that the formula fails to address how the CMVE component will be adjusted when the customer's contractual commitment for replacement capacity is for a period shorter than L.

Commission Conclusion

The comments filed in response to our Open Access NOPR maintained overwhelmingly that determining accurately the competitive market value of the released capacity and energy is a difficult and subjective task. Therefore, we did not prescribe a CMVE by formula as we did for RSE. Instead, we provide options for determining it. Our requirement for the utility to estimate it is CMVE Option 1. However, the customer may contend that the utility will underestimate CMVE under this option so as to increase the customer's stranded cost obligation. In response to these concerns, the Commission adopted CMVE Option 2 because "[t]he customer will test the market and choose the best deal available. Hence, 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."[FN754] The Commission also believes that, because of the potential for disputes over the CMVE component of the formula, many utilities and departing customers would appreciate CMVE Option 2 because it would provide them with a simple and reliable method for determining the CMVE.

However, the Commission recognized the potential for gaming on the part of the customer. To address this potential, the Commission placed certain conditions on the use of Option 2. One of these conditions is that the departing customer must demonstrate that the replacement service is equivalent to that from the current supplier. This provides the utility with the ability to investigate whether the new service is essentially the same, in terms of contract duration, terms and conditions, as that which it currently provides the customer. Any unresolvable disputes over the value of ***12422** non-price benefits contained in the customer's replacement contract, which is SoCal Edison's concern, can be developed during a stranded cost hearing, and the Commission will decide the disputed issues based on the record provided. SoCal Edison's concern with additional bargains outside the contract, which increase the contract price and lower the customer's SCO, is properly addressed through the discovery process. The utility could ask for a copy of agreements between the new supplier and the departing customer, and the customer would be obligated to provide the requested information.

Although we recognize that there may be difficulties in assuring the "equivalence" of the customer's replacement contract, we believe that CMVE Option 2 creates an incentive for the utility to estimate CMVE as accurately as possible (in Option 1), and provides a quick and simple alternative to protracted litigation of the utility's estimate of CMVE. Accordingly, SoCal Edison's and Central Vermont's request for elimination of CMVE Option 2 is rejected. Also, because a utility is permitted to undertake discovery regarding the terms and conditions of the replacement contract, and any contracts or considerations associated with the replacement contract, we do not believe that it is necessary to give the utility the right of first refusal to supply the departing customer under the replacement contract's price, terms and conditions. EEI's "gaming" concerns are best addressed through the discovery process in a stranded cost hearing.

Furthermore, we will not require the departing customer to make a compliance filing containing information about its replacement contract, as the utility can obtain this information through discovery if it is needed and relevant, without automatically burdening the Commission with additional filings or requiring the customer to disclose confidential and irrelevant information. A customer must file replacement contract information only if it chooses to assert that the replacement contract price is relevant to the determination of CMVE.[FN755]

In response to NRECA and TDU Systems, the Commission reiterates that a customer cannot avail itself of CMVE Option 2 if its replacement contract is for a period shorter than L. This restriction is necessary to ensure equivalence of service.

Marketing/Brokering Option Issues

In Order No. 888, the Commission allows the departing customer to market or broker the capacity that it would strand as a result of its decision to purchase power from an alternative supplier. This option is intended to protect a departing customer from a low utility estimate of CMVE, which would result in a higher stranded cost charge to the customer.

ELCON maintains that the option to broker the released power in response to a "low balling" of the CMVE by a utility places an unfair burden on the customer by requiring it to engage in brokering.

SoCal Edison and NIMO argue that a customer choosing the marketing option should pay the utility's estimate of the market value of energy, rather than the average system energy costs for the energy it purchases. SoCal Edison and NIMO argue that the use of average system energy costs is inconsistent with the use of estimated market value used to calculate the customer's stranded cost responsibility and will result in an under-recovery of stranded costs. Florida Power Corp is also concerned that the payment provisions of the marketing option could result in under-recovery of stranded costs. Specifically, Florida Power Corp states that permitting customers to purchase the associated energy at average system variable costs is appropriate if the stranded capacity marketed by the customer is slice-of-system and if the energy used is at the same load factor as the average load factor of the utility's remaining requirements customers. If these conditions are not met, Florida Power Corp states that under-recovery or over-recovery of stranded costs could occur. To prevent this, Florida Power Corp would require the customer to reimburse the utility for the marketed energy at the utility's actual hourly average energy costs for the hours in which the energy is resold.

Occidental Chemical requests guidance as to when a stranded cost is "legitimate" and how the utility will develop an estimate of the capacity to be released. Occidental Chemical also requests clarification regarding the obligations of a departing customer to the replacement buyer and whether the departing customer can resell the capacity under terms and conditions different from those under which it bought it. Similarly, CCEM requests that the Commission clarify that there can be no conditions attached to the former customer's use of the capacity, except for conditions pertaining to safety and reliability. CCEM also contends that the 60-day limit for finding a buyer under the brokering option is too short and should be eliminated. CCEM states that if the customer pays for the capacity in the stranded cost charge, it should have flexibility in disposing of it.

Commission Conclusion

The Commission disagrees with ELCON that the brokering option places an unfair burden on the departing customer. The Commission believes that the marketing/brokering option is another effective incentive for a utility to make a good faith estimate of CMVE. Furthermore, we note that the marketing/brokering option is just that: an option. A customer is not required to exercise the marketing/brokering option, just as it is not required to exercise CMVE Option 2. Rather, the marketing/brokering option is available to a customer who believes it can reduce its stranded cost obligation through marketing or brokering the released power.[FN756]

In response to SoCal Edison, NIMO and Florida Power Corp, the Commission believes that permitting a customer to purchase the associated energy under the marketing option at average system variable costs is appropriate in most instances for at least two reasons. First, the capacity being marketed in all or almost all cases would not be associated with a single asset or subset of assets. Instead, a customer who chooses to exercise this option is purchasing a "slice of the system," i.e., a fraction of the production of all assets. Accordingly, our requirement that the customer purchase the associated energy at average system variable costs is consistent with the notion that it is purchasing a slice-of-the-system. Furthermore, we believe that the customer should have the opportunity to purchase the associated energy at the price it currently pays, and for most customers that price is based on average ***12423** system costs. It is not appropriate to require market value pricing of associated energy when the customer's present payments are based on average system variable costs. For SoCal Edison and NIMO, we further clarify that, when the departing customer markets the released power at a market-based rate and pays average system variable cost for the energy component of the price, the difference between the market price of the power and the average system variable cost determines the market value of the released capacity. When we refer to "purchasing energy at average system variable cost," we refer to compensation for the variable cost component of the sale (mostly fuel cost); we are not referring to the total price of the power sale, which would include a fixed cost recovery component.

We agree with the argument of Florida Power Corp. The Commission recognizes that there may be instances where the departing customer does not purchase energy at average system variable costs. We also recognize that the entity to which the departing customer sells the released capacity may have a usage pattern that differs significantly from that of the departing customer. In this circumstance, the utility should be paid actual hourly average energy costs for the hours in which the energy is resold by the departing customer. Parties should address this issue in their marketing agreement.

In addition, we clarify that the departing customer's capacity charge is the utility's CMVE minus average system variable costs as contained in its estimate of RSE.[FN757] Hence, the capacity charge is the fixed cost that the utility could recover if it sold the power at market value. This approach assumes that the customer choosing the marketing option is buying a slice of the system and buys the energy associated with the released capacity on the same basis as under its contract with the utility.

In response to Occidental Chemical, a stranded cost is legitimate if it meets the criteria established in the Rule. With respect to the obligations of a departing customer to a replacement customer, such obligations will be governed in part by the individual contracts between the parties. However, with respect to Occidental Chemical's question as to whether the departing customer can resell the capacity under terms and conditions different from those under which it bought the capacity, the Commission finds that, at a minimum, the customer is entitled to resell the capacity and energy under the terms and conditions governing its purchase from the utility. However, customers would not be precluded from negotiating different terms and conditions with the utility.

In response to CCEM's concerns, the Commission will not prohibit a utility from attaching conditions to the former customer's use of the system. There may be circumstances (which we have not contemplated) where certain conditions may be necessary, and we do not wish to foreclose such instances at this time. However, we caution utilities against using this to restrict the customer's use of this option. We reiterate our finding in Order No. 888 that the utility should allow the customer to market/ broker the released capacity under terms and conditions comparable to a utility resale of the capacity to a third party.

The Commission disagrees with CCEM that the 60-day period for finding a buyer under the brokering option is too short and should be eliminated. The 60-day period protects both customers and utilities in the event that an acceptable buyer for the power cannot be found. It protects the utility from being stuck with the released capacity for an extended period, during which time it can receive only minimal compensation for it.[FN758] Similarly, the 60-day limit protects the customer by reverting back to the formula if its brokering attempt is unsuccessful. CCEM's argument that the customer who pays for the capacity in the stranded cost charge should have flexibility in disposing of it ignores the fact that under the brokering option (as opposed to the marketing option), the customer does not take title to the released capacity. For these reasons, the Commission continues to believe that a time limit is necessary, and that 60 days is adequate to meet the dual goals described above.

Length of Reasonable Expectation Issues

American Forest & Paper faults the Commission for failing to limit the period of reasonable expectation to a discrete period, such as three to five years. TDU Systems contends that the threat of stranded costs extends well beyond a mere transition period, and therefore, is inconsistent with the Commission's statement that stranded costs are a transition issue. TDU Systems maintains that the period of reasonable expectation should be defined as the shorter of either the term of the terminating contract or the utility's planning horizon as of July 11, 1994. IL Com states that absent a statutory, regulatory or contractual obligation to incur costs or provide service, the length of a utility's expectation to serve a customer beyond its contract expiration should be zero. However, IL Com states that if a statutory or regulatory obligation to serve can be demonstrated by a public utility on a case-by-case basis, extra-contractual recovery may be appropriate but should not exceed three years. IL Com proposes a formula for L that incorporates a three-year cap.

Commission Conclusion

We reiterate that our stranded cost procedure applies to wholesale contracts only if they are entered into on or before July 11, 1994 (and do not contain exit fees or other stranded cost provisions), so that as these contracts end this stranded cost recovery procedure will cease to apply. This fact alone shows that the policy is a transition issue and not a permanent policy for wholesale requirements contracts. Further, it should be remembered that a utility must demonstrate that it had a reasonable expectation of continued service for a time certain (L) before any stranded cost is recognized to exist or recovery permitted. This is not an insignificant demonstration. Moreover, although we decline to establish an outside limit for L, it is likely that the longer the period claimed by the utility, the harder it will be for the utility to demonstrate a reasonable expectation. In any event, to provide recovery of the full stranded cost, it is necessary that the reasonable expectation period not be limited to an arbitrary number, such as three to five years, as suggested by American Forest & Paper.

Regarding the time it takes to complete the transition to a market unaffected by stranded cost considerations, the Commission distinguishes the reasonable expectation period for determining the amount of stranded costs attributable to a departing customer from the period over which the customer pays for stranded costs. For example, a utility may have incurred a cost under the expectation that the customer would remain for another seven years (L). However, the customer could pay that amount ***12424** immediately, over three years, over seven years, or over a longer period. The period of reasonable expectation, L, is unrelated to the repayment period. If all customers were to choose the lump-sum payment option, the transition period to a market completely unaffected by stranded cost recovery would be short.

In response to TDU Systems, we note that its proposal to define the period of reasonable expectation as the shorter of either the term of the terminating contract or the utility's planning horizon as of July 11, 1994 is not foreclosed by our Rule. When faced with a claim for stranded costs, TDU Systems may argue that either of these limit the reasonable expectation period in that instance. However, it would be inappropriate to limit generically the period of reasonable expectation as suggested because the limitation may not fit all circumstances. We reiterate that whether a utility had a reasonable expectation of continued service, and for how long, will be determined on a case-by-case basis, and will depend on the facts and circumstances of each individual case.

With respect to IL Com's argument that absent a statutory, regulatory or contractual obligation to incur costs, the length of a utility's expectation to serve a customer beyond its contract expiration should be zero, the Commission agrees that such obligations are likely to be the principal reasons for a reasonable expectation in most cases, but we would not preclude a utility from introducing other relevant evidence. If a utility can demonstrate that costs were incurred to serve a customer, based on a reasonable expectation of continued service, and if that customer uses the open access provided by Order No. 888 to reach an alternative supplier, leaving the utility with unrecovered costs, the utility should be allowed to make its case for recovery of those costs based on whatever evidence it chooses to offer.

Implementation Issues

SoCal Edison is concerned that, under the framework established in Order No. 888, a customer could request numerous estimates of stranded costs based on different alternative supply scenarios and departure dates, to which the utility would have to respond in a 30-day period. SoCal Edison states that the Commission should reasonably limit the number and types of requests. SoCal Edison maintains that if the number and type of a customer's requests are unduly burdensome or unreasonable in the utility's view, the utility should be permitted to refuse the requests. Under SoCal Edison's approach, the customer would have the right to petition the Commission to demand that such studies be undertaken.

SoCal Edison also argues that the Commission should allow a utility to assess a reasonable charge to cover administrative costs associated with developing the studies required to produce estimates of stranded cost responsibility.

TDU Systems states that the 30-day period allowed for a customer to respond to a utility's notice of alleged stranded costs is too little time to perform an adequate analysis. In addition, TDU Systems and NRECA maintain that a customer should not be bound by its estimate of stranded cost obligation as filed in a petition for declaratory order or a section 205 or 206 proceeding. They contend that certain elements of the formula depend heavily on data in the public utility's possession, and that the Rule, as written, will encourage the customer to present a low-end estimate of stranded cost liability. TDU Systems and NRECA maintain that the Commission should instead require the customer to state its binding estimate at the close of the discovery period when it presumably would be in possession of the data necessary to make a realistic estimate of the stranded cost floor.

PSE&G argues that a utility should be able to begin recovering stranded costs right away, subject to refund pending the outcome of the proceeding, to eliminate any incentive a customer would have to delay proceedings so as to delay payment of stranded costs.

Commission Conclusion

Regarding SoCal Edison's concern about numerous requests for estimates of stranded costs, we do not believe that the number of requests will rise to the level of "unduly burdensome" or "unreasonable" in most instances. However, if this problem occurs, a utility can petition the Commission for relief, and we will consider each petition on a case-by-case basis.

The Commission does not agree with SoCal Edison that a utility should be permitted a special charge to cover the cost associated with providing a stranded cost estimate. Such costs are likely to be de minimis. Given that Order No. 888 provides an opportunity for full recovery of stranded costs, we do not believe it is appropriate for a utility to charge a customer an additional fee for asking whether it can expect a stranded cost claim.

The Commission also disagrees with TDU Systems that the 30-day customer response period is too short. No utility has argued on rehearing that the 30-day utility response to a request for an estimate is too short, and only TDU Systems argues that the

30-day customer response to the utility's estimate is too short. The 30-day period is intended to speed the negotiation process, with the goal of settling stranded costs disputes without Commission involvement. Order No. 888 requires a utility to provide an estimate of stranded cost responsibility within 30 days of the customer's request for an estimate. We do not believe it is unreasonable to require the customer to respond in like time. Accordingly, we will not modify the 30-day response requirement.

Furthermore, the Commission is unpersuaded by TDU Systems' and NRECA's argument that a customer should be bound by its estimate of stranded cost obligation only after the close of the discovery period. Order No. 888 requires the utility to provide detailed support for its stranded cost estimates, and this information should be adequate to allow the customer to develop its own estimate of any stranded cost obligation.

In response to PSE&G, we clarify that recovery of stranded cost claims filed under section 205, 206, or 211/212 will be governed by these sections and the Commission's promulgating regulations thereto.

Net Benefit Issues

EGA and IMPA argue that the revenues lost approach does not capture the net utility benefits that result from open access. EGA states that no stranded costs should be imposed on any one "lost" customer if the utility is a "net winner," that is, where the benefits from the new competitive regime outweigh the utility's stranded costs. EGA states that the formula is unclear as to how the revenues lost approach will take into account the following three potentially beneficial effects of competition: (1) an expanded customer base as a result of enhanced transmission access; (2) reductions in the cost of purchased power, which is resold by a utility; and (3) a utility's ability to obtain higher than cost of service rates for electricity. Freedom Energy argues that the potential future benefit should be factored into the revenues lost calculation.

IMPA maintains that a mechanism should be provided for recovery of the benefits of open access, particularly if a utility does not seek stranded cost recovery. IMPA states that it is economically inefficient for consumers of generation and transmission services to pay stranded costs to those suppliers that have higher than average cost generation, while the benefits from ***12425** increases in asset value are not shared with the consumers or used to pay for other utilities' stranded costs. IMPA further contends that if the customer's departure as a power customer frees up the generating capacity for remarketing through the use of the transmission system, section 212 of the FPA, as modified by the Energy Policy Act, supports recognition of such benefits in the price paid by the customer for its continued usage. Finally, IMPA maintains that if a transmission provider seeks stranded cost recovery for an asset that appears "high cost" due to its relative youth, the asset's future lower cost as an older unit must also be included in the calculation; otherwise the departing customer will be denied the long-term average benefit of the generating asset.

Multiple Intervenors contend that there should be consistent treatment of all assets that deviate from fair market value. For example, if a utility is allowed to recover the difference between the book value of an asset and its lower market value, then that amount should be offset by the appreciated value of any assets that have a market value higher than book value. Similarly, ELCON and Freedom Energy are concerned that the revenues lost approach may overcompensate a utility for stranded costs because it fails to account for the fact that uneconomic assets may be offset by the increased economic value of other assets in a deregulated environment.[FN759] Freedom Energy states that losses may occur in the short run, but in the long run the utility may be better off.

Commission Conclusion

The Commission believes that the suggestion by EGA and others that a long-run comprehensive analysis be undertaken every time a customer departs, in order to determine whether the utility would eventually be a net winner, is unworkable. Identifying the competitive market value for power during the reasonable expectation period (L) is hard enough; EGA would have us also find the market value of the power for an indefinite time after the expectation period ends. Further, attempts to define which benefits are the result of Order No. 888 would, at the very least, be unwieldy and highly subjective. The Commission's approach, on the other hand, is far less subjective and more likely to produce a reasonable result.

With respect to the specific "potentially" beneficial effects of competition during the period L, which EGA states should be used to offset stranded costs, the Commission finds these benefits to be questionable at best. However, if these potential benefits occur, the Rule's stranded cost approach accommodates them. For example, our clarification (infra) that the formula addresses load growth responds to EGA's first concern that the formula should take into account the expanded customer base that results from open access. EGA's second concern, i.e., that the formula should reflect reductions in the cost of purchased power, is misplaced. If, in a future market-based pricing world, a utility can purchase power at a lower cost, it must either pass this lower cost through to customers in its cost-based rates or sell power at similarly low market-based rates to other customers. In either case, except for possible timing considerations, it is unable to profit by buying low and selling high. If a utility has such a hypothetical benefit before the customer departs, the customer may file a section 206 complaint prior to the termination of the existing contract, so that the resulting rates, reflecting the reduction in the cost of purchased power, could be used to calculate RSE. Lastly, if a utility can sell at market-based rates that are higher than cost-based rates (other than in the speculative long run), it would not qualify to recover stranded costs.

In addition, ELCON's and Freedom Energy's concern that utilities may be overcompensated under the revenues lost approach is based on a study that assumes a fully deregulated environment. There is no basis for this assumption over the next several years. Furthermore, it is highly speculative whether a particular utility will necessarily be better off in future markets as the study predicts. This is especially so because Freedom Energy's argument that future benefits should be used to offset stranded costs appears to assume a short reasonable expectation period, L. We do not find merit in Freedom Energy's suggestion that events beyond the reasonable expectation period should be factored into the stranded cost calculation.

The Commission also believes that IMPA's benefit reallocation proposal is inappropriate and unworkable. It would require a utility not requesting stranded cost recovery to share with its wholesale customers any future benefits that would accrue to it as a result of Order No. 888. Customers have purchased power from utilities at cost-based rates that have been found to be just and reasonable by this Commission. Such purchases in no way convey an ownership interest in the facilities used to provide service. The rationale for stranded cost recovery, i.e., payment for investments made to serve a customer under the utility's reasonable expectation of continuing to serve, cannot be converted into what would be in effect an ownership interest with the right to receive a share of profits from future sales. Moreover, IMPA's argument assumes that utilities whose assets have a book value less than market value will be able to charge market-based rates for their capacity. This assumption is unrealistic for many utilities, and therefore cannot be relied upon as basis for a generic policy. However, even if all utilities could charge market-based rates, economic efficiency would argue strongly against such utility payments to departing customers. Specifically, there would be little or no incentive for an efficient, low cost utility to seek the best deal in the power market if the profits must be credited back to its former customers, or other utilities' customers, as IMPA suggests. Therefore, while IMPA's symmetry argument (i.e., customers must pay stranded costs so equity requires utilities to pay customers any benefits that result from open access) may have surface appeal, it would serve to undo the goal of Order No. 888—that is, to promote competition and economic efficiency in bulk power markets. The Commission considered carefully the issue of symmetry in Order No. 888 and provided the appropriate utility-customer symmetry: a utility is entitled to make the case that it expected the customer to remain a customer longer than the term of the contract and the customer is entitled to make the case that the term of an existing contract should be shortened.

We also reject IMPA's argument that section 212 of the FPA requires recognition in transmission rates of any generation benefits that accrue to a utility as a result of Order No. 888. Section 212 requires the Commission to consider all costs incurred by the transmission provider in providing the service, "including taking into account any benefits to the transmission system of providing the transmission service." [FN760] We do not interpret this to refer to the resale of a utility's generation freed-up as a result of Order No. 888.

IMPA's argument that if a transmission provider seeks stranded cost recovery for an asset that appears ***12426** "high cost" due to its relative youth, the asset's projected future lower (depreciated) cost as an older unit must also be included in the calculation, improperly focusses on an individual asset. As we explained above, the revenues lost approach is not an asset-by-asset approach, but an approach that looks at a utility's current rates which are based on all the utility's assets, including typically a mix of facilities of various ages.

Lastly, the revenues lost approach automatically includes an offset of the type described by Multiple Intervenors, ELCON and Freedom Energy. The revenue stream is based on present rates, which are based on the net book value of all of the underlying assets used to provide the service. If present rates include some assets that have a market value that exceeds net book value (for example, plants that are almost fully depreciated), the formula automatically captures the described offset because the revenue stream is based on the lower book value of the utility's assets rather than their higher market value.

Miscellaneous Formula Issues

Rehearing Requests
American Forest & Paper argues that the definition of wholesale stranded costs in section 35.26(b)(1) is overly inclusive; rather than using a gross measure of stranded costs, it believes the regulations should adopt a net measure that accounts for a utility redeploying its assets in a competitive market at market price. American Forest & Paper also maintains that the formula fails to reward efficient utilities or those that already have borne the pain of restructuring. On the contrary, it argues that the Commission's definition artificially and unjustifiably improves the competitive position of the inefficient utilities. American Forest & Paper further contends that the formula fails to allocate the risk of non-mitigation to utilities, the entities that are in the best position to mitigate such costs, but rather places the risk on customers by requiring customers to challenge the utility's CMVE.

Commission Conclusion
In response to American Forest & Paper, we note that the definition of wholesale stranded cost in section 35.26(b)(1) should not be looked at in isolation. Although that definition does not specifically mention the subtraction of the competitive market value of the released power from RSE, the revenues lost formula, which is set forth in section 35.26(c)(2)(iii), does. The formula explicitly provides that a customer's stranded cost obligation is to be calculated by subtracting the estimated competitive market value (of the released power) from the revenue stream estimate.

In response to the argument that the formula fails to reward the efficient utility that has already borne the pain of restructuring, we note that our intention in providing stranded cost recovery was not to review or reward utility business decisions that preceded this Rule. Our decision was, at bottom, based on equity for a utility that chooses to make a case to regulators for recovery of costs stranded by transmission access. Furthermore, we disagree that the definition of stranded costs artificially and unjustifiably improves the competitive position of an inefficient utility. Instead, the Commission believes that to deny stranded cost recovery would violate the pre-existing regulatory compact and would unjustifiably place certain utilities with stranded costs at a financial disadvantage.

With respect to American Forest & Paper's concern about mitigation risk, the Commission requires the utility to mitigate, or reduce, its stranded cost by reselling the released capacity at a price as high as the market allows. In addition, Order No. 888 contains several other incentives (e.g., the marketing/brokering option) to protect the departing customer from paying an excessive stranded cost charge. These incentives serve to mitigate stranded costs. Regarding the customer's "requirement" to challenge the utility's CMVE, we view this as the customer's right to challenge the utility's stranded cost estimate, which is like its right to challenge a cost item in any rate case.

Rehearing Requests
NRECA and TDU Systems maintain that the formula fails to account for any savings or reductions in fuel costs attributable to a customer's departure. NRECA and TDU Systems contend that the utility's fuel costs will decrease equivalent to the incremental fuel costs associated with the energy not taken. They maintain that if the customer's associated revenues are based on average

fuel cost energy charges, stranded costs should be offset by the reduction in average system fuel costs directly related to the incremental fuel costs savings. They argue that any stranded cost recovery mechanism should properly reflect such offsetting savings.

Commission Conclusion

The Commission disagrees with NRECA and TDU Systems that the formula fails to account for any savings or reductions in fuel costs attributable to a departing customer. The formula automatically accounts for fuel costs by assuming that the utility will be reselling the same capacity and energy to another buyer, presumably at a lower price. The lower price can be viewed as contributing less to capital cost and purchased power cost recovery, but containing the same fuel cost component. Under this approach, any decrease in fuel cost caused by no longer serving the departing customer is offset by the increased fuel cost of serving the new customer. Hence, there is no fuel costs savings to reflect.

Rehearing Requests—Divestiture

CCEM continues to support divestiture of generating assets as a precondition to a utility's authority to recover stranded costs. CCEM maintains that divestiture is the only way to obtain an accurate determination of CMVE on a net asset basis.

Commission Conclusion

The Commission disagrees that divestiture is the only way to obtain an accurate measure of CMVE and we continue to believe that mandatory asset divestiture does not need to be a requirement for stranded cost recovery. However, the Rule (Section IV.J.10) states that we are willing to consider case-specific proposals for dealing with stranded costs in the context of any voluntary restructuring proceeding instituted by an individual utility.

Rehearing Requests—Load Growth and Excess Capacity

TDU Systems and NRECA argue that the formula fails to take into account the effect of load growth on the recovering utility's revenues. They maintain that if the recovering utility is able to sell the released capacity to new or existing customers, the rationale for stranded cost recovery would be eliminated. Similarly, Arkansas Cities argues that the formula is an imperfect indicator of a utility's stranded costs because it does not explicitly take into account the role played by the utility's having (or not having) excess capacity. PA Munis maintains that as a prerequisite to stranded cost recovery, a utility should be required to prove that the customer's use of open access transmission actually resulted (or could result) in excess capacity on its system.[FN761]

Commission Conclusion

We clarify that our stranded cost policy does take into account the effects of load growth and excess capacity. The formula is used to calculate the value of stranded costs only if the Commission determines that the utility has proved it has legitimate, prudent, and verifiable stranded costs. For example, it must pass our reasonable expectation test before the formula applies. However, costs may be stranded only if they are not fully recovered from another customer; that is, the released capacity may be either left unsold or resold at a price below full embedded cost.

The resale may be either to a new third-party customer or to remaining native load. If the released capacity is resold to a third-party customer at full embedded cost-based rates, then no costs would be stranded and the formula would not have to be used. Released capacity would also be considered "resold" if its cost is subsequently (and without delay) included in the rate base of the utility's retail and wholesale native load. It may be included if it is needed, in the judgment of the appropriate state or federal regulatory body, for native load growth plus reliability reserve. In this case the cost is not stranded if it is fully recovered in the cost-based rates paid by native load. If the full embedded cost rate is paid by the new purchaser for the capacity released by the departing customer, the parties may argue either that there is no stranded cost or that the formula produces a stranded cost obligation of zero because CMVE equals the embedded-cost rate that the utility charges its wholesale and retail native load customers; hence RSE equals CMVE.

In response to Arkansas Cities, if the released capacity was included in the Commission-approved cost-based rates paid by the departing customer, we presume that such capacity is not "excess" capacity. The departing customer's rate (which produces annual revenues, RSE) for the released capacity includes capacity that regulators have approved as needed to meet the needs of requirements customers, including capacity needed for reliability reserve. The only excess capacity issue is whether the released capacity becomes "excess" because of the customer's departure, that is, whether the departure strands costs because the utility cannot find a buyer for the capacity. If the released capacity is "excess" capacity that is excluded from subsequent native load rates because it is not needed for native load, its cost may be eligible for stranded cost recovery under the formula. Thus, contrary to the arguments made by TDU Systems, NRECA, Arkansas Cities, Pa Munis and others, the revenues lost formula does take load growth and excess capacity into account appropriately in determining the departing customer's stranded cost obligation. For this reason, we reject the arguments made by commenters that the formula is flawed.

Rehearing Requests—Tax Treatment of Nuclear Decommissioning Costs

EEI and Nuclear Energy Institute request clarification that the Commission did not intend Order No. 888 to change the IRS's tax treatment of nuclear decommissioning costs. To be tax deductible, nuclear decommissioning costs must be part of a utility's regulated cost of service. EEI and Nuclear Energy Institute seek clarification that costs included in a utility's stranded cost calculation continue to be considered by the Commission as included in the utility's cost of service.

Commission Conclusion

The requested clarification is granted. We clarify that costs included in a utility's stranded cost calculation continue to be considered by the Commission as included in the utility's cost of service.

Rehearing Requests—Application of Formula to Stranded Costs Associated With Retail-Turned-Wholesale Customers and Retail Wheeling Customers

OH Com, MO Com and KS Com maintain that the Commission's formula is inappropriate for calculating stranded costs associated with retail wheeling customers and/or retail-turned wholesale customers. They contend that the formula would be impractical to administer and would produce inaccurate results given the enormity of the calculations and assumptions involved. Suffolk County argues that the formula is flawed for retail-related stranded costs because the Commission cannot guarantee any retail rates into the future because it has no basis for even speculating about how retail rates may be changed by subsequent state action.

Commission Conclusion

With respect to stranded costs caused by retail wheeling, the Commission determined in Order No. 888 that the formula was inappropriate, and that if the Commission had to determine stranded costs associated with retail wheeling it would do so on a case-by-case basis. [FN762] However, the formula does work for stranded costs associated with retail-turned-wholesale customers because the newly formed municipal utility would have the resources to engage in marketing or brokering and would have a marketable product. This stands in contrast to individual retail customers, most of whom are unlikely to have the resources to engage in marketing or brokering and would have very small amounts of energy for sale. Although the calculations necessary to estimate stranded costs associated with retail-turned-wholesale customers are somewhat more involved than stranded costs associated with wholesale contracts, they are not impossible or overly burdensome. Accordingly, we affirm our finding in Order No. 888 that the formula is appropriate in the retail-turned-wholesale context.

Rehearing Requests

Allegheny Power states that stranded cost recovery should not be permitted if a utility recovers large amounts through exit fees, then uses the freed capacity to make sales in the market at anything over variable costs. Allegheny Power argues that a utility with nuclear generation, which has a low variable cost, can dump power on the market because its fixed costs are subsidized by stranded cost recovery. Allegheny Power requests that the Commission recognize that this distortion of the competitive market should not be facilitated by stranded cost recovery.

Commission Conclusion

Allegheny Power's concern that a utility recovering stranded costs will use those revenues to subsidize sales in the market at anything above variable costs is misplaced. In the power market, power pricing decisions are based on whether the utility can recover its variable cost, plus earn some contribution to capital costs. Stranded cost revenues are not relevant. This fact is demonstrated by considering the situation where no stranded cost revenues are provided to a utility with nuclear generation as described by Allegheny Power. The utility, in pricing power for off-system sales, would still face the same choice, i.e., make the sale and earn some minimal contribution to capital, or forego the sale and earn nothing. The Commission's decision to provide recovery of stranded costs does not change the economics involved in utility power pricing decisions, and does not lead to the type of market distortion that concerns Allegheny Power. ***12428**

Rehearing Requests

SBA asserts that determining the proper amount of stranded cost recovery is an integral step in the deregulation process.[FN763] It expresses concern that the revenues lost formula can be abused through the manipulation of the necessary financial statements of the parties and that such abuse could be harmful to small businesses. SBA requests that the Commission solicit its input, as well as the input of the small business community and small business organizations, when determining whether the proposed stranded cost recovery amount in a particular case is fundamentally fair in terms of maintaining a viable environment for small businesses.

Commission Conclusion

In response to SBA's request, we note that SBA, or any interested small business organization, has the opportunity to provide input to the Commission in a particular stranded cost proceeding by filing a motion to intervene in that proceeding.[FN764]

10. Stranded Costs in the Context of Voluntary Restructuring

No rehearing requests were filed on this issue. The Commission reaffirms 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. [FN765]

11. Accounting Treatment for Stranded Costs

No rehearing requests were filed on this issue. The Commission reaffirms Order No. 888's treatment of this issue.[FN766]

12. Definitions, Application, and Summary

In Order No. 888, we defined "wholesale stranded cost" in section 35.26(b)(1) as follows:

(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. [FN[767]]

We rejected requests by commenters in this proceeding to expand the definition to include the situation where a wholesale requirements customer or a retail-turned-wholesale customer ceases to purchase power from the utility without using the transmission services of that utility.[FN768] We explained that 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. We noted that the premise of this Rule is that, where a customer uses Commission-mandated transmission access of its former power supplier to obtain power from a new generation supplier, the customer must pay the costs that were incurred to provide service to the customer under the prior regulatory regime. We indicated that 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.[FN769]
We also decided to retain the requirement that stranded costs be "legitimate, prudent and verifiable," rejecting requests by some commenters to eliminate the term "prudent" from the definition of stranded costs.[FN770] We explained that 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. We said that 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. We concluded that the Commission cannot make a blanket assumption that all claimed stranded costs will have been prudently incurred, but we clarified that we do not intend to relitigate the prudence of costs previously recovered.

Rehearing Requests—Definitions of "Wholesale Stranded Cost" and "Wholesale Requirements Contract"
As discussed in Sections IV.J.1 and IV.J.6, supra, a number of entities ask the Commission to expand the scope of stranded cost recovery allowed under the Rule to include "bypass" situations (i.e., situations in which a departing customer does not use its former supplier's transmission system to reach another supplier). Coalition for Economic Competition asks the Commission to revise the definition of "wholesale stranded cost" to accomplish that result. It notes, for example, that the reference in the definition to "newly created wholesale power sales customer" creates an ambiguity and may provide a loophole to evade stranded costs through municipal annexation.

El Paso expresses concern that a retail-turned-wholesale customer could attempt to avoid its stranded cost responsibility simply by having its outside power supplier be the "wholesale transmission customer" (i.e., the entity that formally requests transmission service from the transmitting utility). El Paso asks the Commission to clarify that a retail-turned-wholesale customer is responsible to the transmitting utility for stranded costs regardless of whether it or its outside power supplier is the "transmission customer" of the transmitting utility. El Paso asks the Commission to revise section 35.26(c)(1)(vii) (which presently provides for recovery from retail-turned-wholesale customers through section 205-206 or 211-212 wholesale transmission rates) to provide for the recovery of stranded costs directly from retail-turned-wholesale customers (through an exit fee or lump sum payment).

Utilities For Improved Transition asks the Commission to expand the definition to include costs incurred to provide service to "a wholesale requirements customer that loses retail load because of retail wheeling, ***12429** municipalization of retail load, the creation of a new customer, or because retail customers have bypassed its system through transmission or distribution taps to other suppliers or by other means."[FN771] Utilities For Improved Transition argues that, in the case of retail wheeling and municipalization, these costs are incurred because of open access tariffs. It further submits that the Commission also should include costs incurred because of taps (interconnections) to other systems to avoid encouraging uneconomic bypass as a way to avoid stranded cost charges.

APPA expresses concern that the definition in section 35.26(b)(4) of "wholesale requirements contract" as "a contract under which a public utility or transmitting utility provides any portion of a customer's bundled wholesale power requirements" could be read as including a bundled sale of capacity regardless of whether the seller undertook to meet the customer's load growth. As a result, APPA submits that the definition could include coordination arrangements. It is APPA's position that the Commission could not, or should not, have intended to allow stranded cost recovery for such contracts. APPA asks the Commission to specify on rehearing that a "wholesale requirements contract" is a bundled power and transmission arrangement that includes the obligation to meet some or all of the customer's load growth, and that all other services are coordination arrangements to which the stranded cost recovery rules do not apply.

Commission Conclusion

We will reject the requests for rehearing that ask the Commission to expand the scope of stranded cost recovery allowed under the Rule to include situations in which a wholesale requirements customer (or a retail-turned-wholesale customer) ceases to purchase power from the utility without using the transmission services of that utility. As we explain in Sections IV.J.1 and IV.J.6, supra, any costs that the utility might incur as a result of the loss of the customer in these scenarios would be outside the scope of Order No. 888. However, as discussed in Section IV.J.6, we grant rehearing on the municipal annexation issue.

We share El Paso's concern that a retail-turned-wholesale customer should not be able to avoid its stranded cost responsibility simply by having its outside power supplier be the entity that formally requests unbundled transmission service from the utility. As we explain in Section IV.J.6, supra, in response to a similar concern expressed by Puget, we have revised the definition of "wholesale stranded cost" in section 35.26(b)(1)(ii) to cover this situation. As revised, that section provides that "[w]holesale stranded cost means any legitimate, prudent and verifiable cost incurred by a public utility or a transmitting utility to provide service to: * * *. (ii) a retail customer that subsequently becomes, either directly or through another wholesale transmission purchaser, an unbundled wholesale transmission services customer of such public utility or transmitting utility.

We will deny Utilities For Improved Transition's request that the Commission expand the definition to include costs incurred to provide service to "a wholesale requirements customer that loses retail load because of retail wheeling, municipalization of retail load, the creation of a new customer, or because retail customers have bypassed its system through transmission or distribution taps to other suppliers or by other means." Utilities For Improved Transition, in effect, is asking that the Commission allow the recovery of costs that may be stranded due to the loss of an indirect customer and to expand the scope of the "wholesale stranded costs" for which Order No. 888 provides an opportunity for recovery. As we discuss in Section IV.J.1, supra, the Commission does not believe it is appropriate to expand the scope of the stranded cost recovery opportunity provided under this Rule to include costs that may be stranded due to the loss of an indirect customer (i.e., a customer of a wholesale requirements customer of the utility). The reasonable expectation analysis would apply only to the direct wholesale requirements customer of the utility, not to the indirect customer. A utility may seek to recover stranded costs from a direct wholesale customer (subject to the requirements of the Rule), but it is up to the direct wholesale customer, through its contracts with its customers or through the appropriate regulatory authority, to seek to recover stranded costs from its customers.

In response to APPA's argument that the definition of "wholesale requirements contract" in new section 35.26(b)(4) of the Commission's regulations could be read as including coordination arrangements, we clarify that it does not. The opportunity to recover stranded costs applies only to bundled power contracts where the utility can demonstrate that it incurred costs to provide service to a customer based on a reasonable expectation of continuing service to the customer beyond the contract term. Coordination arrangements could not meet the cost incurrence and reasonable expectation prerequisites of Order No. 888, and therefore a customer served under such an arrangement would not be subject to stranded cost charges.

Rehearing Requests—Relitigation of Prudence

A number of entities express concern that, notwithstanding the Commission's stated preference not to relitigate prudence, Order No. 888 leaves the door open for subsequent litigation of prudence issues. Centerior asks the Commission either to remove "prudent" from the definition or to clarify that "prudent" means all costs found prudently incurred by the state commissions. Centerior asks the Commission not to relitigate prudence in the operation and maintenance of a plant or the prudence of continuing to own a plant when cheaper alternatives become available. Other entities (including EEI, PSE&G, and Nuclear Energy Institute) similarly ask the Commission to clarify that it does not intend to relitigate costs that are already in rates when calculating the revenue stream estimate. Nuclear Energy Institute states that, in the case of nuclear plants, significant prudence proceedings have already been conducted and, by definition, the embedded capital costs included in current rates to customers are prudent.

PSE&G recommends that if costs that form the basis for a utility's claimed stranded costs are already included in filed rates and are no longer subject to refund, those costs should be treated as per se prudent. Southern states that if the Commission does not strike the word "prudent" from the definition of stranded costs, at a minimum it should modify the Rule to establish a rebuttable presumption of prudence that must be overcome by the departing customer.

PSE&G and Carolina P&L submit that if prudence challenges under the Rule are retained on rehearing, they should be subject to the same standards as any other prudence challenge, namely the "reasonable person test" under which prudent costs are those "which a reasonable utility management * * * would have made, in good faith, under the same circumstances, and at the relevant point in time." [FN772] PSE&G and Carolina P&L ask the Commission to limit the prudence review to the reasonableness of the costs that were incurred to provide wholesale requirements service based on the ***12430** utility's reasonable expectation of continued service. They ask the Commission to clarify that it will not permit prudence proceedings to devolve into collateral attacks on stranded cost recovery and unfocused debates on the sufficiency of the utility's efforts to adapt to changes in the industry, such as its decisions on staffing reductions and asset write-offs.

Commission Conclusion

In Order No. 888, we specifically stated that we do not intend to relitigate the prudence of costs previously recovered but that we would not preclude parties from raising prudence in stranded cost proceedings. Because we believe that this approach adequately ensures that the prudence of costs previously recovered at this Commission or a state commission will not be relitigated for stranded cost purposes, we will reject the rehearing requests that seek elimination of the term "prudent" from the definition of stranded costs.[FN773] However, we make certain clarifications below in response to the rehearing petitions.

As an initial matter, we clarify that the Commission's determination in Order No. 888, which is reaffirmed here, is the same approach the Commission traditionally has followed regarding prudence matters.[FN774] Costs are assumed prudent unless a party or the Commission raises a serious doubt as to prudence; then the burden is on the utility to prove that costs were prudently incurred.[FN775] If costs have previously been recovered in rates (either following an explicit prudence determination or based on an implicit assumption of prudence because no one raised prudence), they cannot be relitigated. However, if prudence has not previously been litigated or if certain costs or activities have become imprudent,[FN776] a party may raise the issue as it pertains to future cost recovery.[FN777] The Commission intends to apply the same prudence standards with regard to future cost recovery, including stranded costs.

We further clarify that we do not intend to relitigate, for purposes of stranded cost determinations involving retail-turned-wholesale customers or unbundled retail customers, the prudence of costs for which rate recovery has been allowed by state commissions. Similarly, in calculating the revenue stream estimate, we do not intend to relitigate the prudence of any costs for which rate recovery has been allowed by this Commission or a state commission.[FN778]

In response to PSE&G and Carolina P&L, we also clarify that, in cases in which we do entertain stranded cost claims, the standard to be used for reviewing the prudence of a utility's costs is the "reasonable person" test that we apply in other contexts.[FN779] This test gives utility managers "broad discretion in conducting their business affairs and in incurring costs necessary to provide services to their customers." [FN780] It asks whether the costs are those "which a reasonable utility management * * * would have made, in good faith, under the same circumstances, and at the relevant point in time." [FN781] We clarify that we do not intend to permit prudence proceedings to become an opportunity for collateral attacks on stranded cost recovery.

K. Other

1. Information Reporting Requirements for Public Utilities

In the Final Rule, the Commission indicated that it will not 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.[FN782] It explained that the information it collects from public utilities is necessary to carry out its jurisdictional responsibilities and is used, among other things, to evaluate the reasonableness of cost-based rates subject to the Commission's jurisdiction and the operation of power markets.[FN783] Moreover, the Commission noted its explanation in ConEd:

[r]eports required to be submitted by Commission rule and necessary for the Commission's jurisdictional activities are considered public information. 18 C.F.R. §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. [[FN784]]

The Commission expressed sensitivity 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 required from other public utilities (e.g., public utility marketers) authorized to sell at market-based rates, but explained that the record in the proceeding is insufficiently developed to make and support a well-informed decision requiring a different reporting scheme, particularly given the industry's current rapid pace of change. Also, the Commission indicated that it was 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.

However, the Commission stated that it will monitor its 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.

Rehearing Requests

Allegheny asserts that this proceeding is the proper forum to evaluate the public disclosure of information required from public utilities because it is necessary to avoid disparate treatment of market participants that violates the comparability standard and leads to market distortions. It argues that the Commission should eliminate the requirement to file data on Form No. 1 and other informational filings, or alternatively the Commission should protect the information as proprietary and confidential.

Centerior argues that the Commission should eliminate the public disclosure of the cost-based generation rates and provide for symmetry between the information provided by public utilities ***12431** and power marketers by eliminating the reporting requirements.

EEI indicates that it intends to petition the Commission for further action on information reporting requirements in the near future. It adds that it seeks to work with the Commission in streamlining the reporting process and in creating a level playing field.

Commission Conclusion

We are not persuaded that the information reporting requirements for public utilities need to be changed at this time. Very simply, it is premature to take such a step at a time when much of the industry is still under cost-based rate regulation for sales of electric energy and when corporate restructuring, including utility mergers, is occurring at a rapid pace. On rehearing, entities have merely reiterated the arguments that we previously addressed in the Final Rule and have presented no evidence that the competitiveness of traditional public utilities is being impaired by their having to submit primarily annual reports that are filed months after the fact. Accordingly, we will continue to require public utilities to submit the information required by our rules and regulations and we will monitor our reporting requirements as the industry environment continues to change.

2. Small Utilities

The Commission noted that it was sympathetic to the array of concerns raised by small public utilities and small transmission customers and explained that the regulations it was 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.[FN785] However, the Commission explained, 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.

The Commission recognized 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. In addition, the Commission explained that for small public utilities that own no generation and buy at wholesale on a radial transmission line from another utility's grid or if their 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.

The Commission further explained that 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 the Commission will require applications and fact-specific determinations in each instance.

In addition, the Commission indicated that it will apply the same standards to any entity seeking a waiver. The Commission explained that 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. The Commission concluded that it 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. However, the Commission explained that they will have to apply for this waiver and demonstrate that they qualify for the waiver.

Rehearing Requests

APPA asserts that absent a finding that a non-public utility has market power or has exhibited undue discrimination, the non-public utility should be granted a waiver.

Michigan Systems asks that the Commission modify the Rule to provide a blanket waiver for systems that by their nature cannot have market power over transmission and do not have the personnel to separate functions. It also asserts that the Final Rule waiver procedure is cumbersome and time consuming.

Tallahassee asks the Commission to clarify that it will liberally apply its waiver policy to small public utilities even if they run a control area. It asserts that the proper focus of concerns over competition are a utility's size, its ability to manipulate the market, and how it operates its control room.

CAMU asks the Commission to clarify that the small utilities waiver will be generally available to those entities lacking market power because only utilities with market power are capable of subverting the transmission market.

Commission Conclusion

The issues raised with respect to waivers for small utilities are more appropriately addressed in individual fact-specific proceedings. As we explained in the Final Rule, [b]ecause 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.[FN[786]]

Indeed, we have granted a variety of waiver requests by small utilities since issuance of the Final Rule.[FN787]

3. Regional Transmission Groups

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

In the Final Rule, the Commission expressed its continued support for the development of RTGs and encouraged regional tariffs.[FN788] To further encourage the development of RTGs, the Commission stated that it will accept regional open access transmission tariffs developed by RTGs that are consistent with the objectives of this Rule.

b. Deference To RTGs to Develop Regional Tariffs and Prices

In the Final Rule, the Commission indicated its intent to give deference to the planning, dispute resolution, and decisionmaking processes of an RTG. [FN789] With respect to pricing proposals submitted by RTGs, the Commission stated that RTGs may be able to develop solutions to such problems as loop flows through innovative flow-based pricing methodologies.

Rehearing Requests

No requests for rehearing addressed this matter.

4. Pacific Northwest

In the Final Rule, the Commission encouraged the filing of regional open access transmission tariffs.[FN790] It also explained that the Final Rule pro forma tariff contains provisions allowing utilities to modify tariff terms to reflect prevailing regional practices. The Commission concluded that this should permit entities in the Pacific Northwest ***12432** 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.

Rehearing Requests

No requests for rehearing addressed this matter.

5. Power Marketing Agencies

a. Bonneville Power Administration (BPA)

In the Final Rule, the Commission stated that 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.[FN791] However, the Commission indicated three circumstances under which the Commission may review BPA's transmission access and pricing policies.

With respect to stranded costs, the Commission clarified that the 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 explained that the Rule does not address stranded cost recovery by BPA under the Northwest Power Act.

Rehearing Requests

BPA asks the Commission to clarify that it did not intend to address stranded cost recovery by BPA under either the Northwest Power Act or section 212(i) of the FPA. If Order No. 888 is intended to govern stranded cost recovery by BPA in the case of Commission-ordered transmission under section 211, BPA asks the Commission for an opportunity to brief the issue on rehearing.

Commission Conclusion

We clarify that our review of stranded cost recovery by BPA would take into account the statutory requirements of the Northwest Power Act and the other authorities under which we regulate BPA (e.g., DOE delegation for interim rate approval) and/or section 212(i), as appropriate.

b. Other Power Marketing Agencies

In the Final Rule, the Commission explained that 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.[FN792] However, the Commission did state that 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.[FN793]

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, the Commission clarified that the Final Rule pro forma tariff will allow SEPA to continue to schedule service for these customers. The Commission also clarified that SEPA, as a seller of power to multiple purchasers inside several control areas, is eligible to receive network service.

Rehearing Requests

Entergy asks the Commission to clarify that SEPA can obtain network service only in the same manner as any other customer and that there was no intent in the Rule to create a special type of network service for SEPA.

Commission Conclusion

We will clarify that for purposes of obtaining network service SEPA is to be treated as any other customer.

6. Tennessee Valley Authority

In the Final Rule, the Commission stated that 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.[FN794] However, the Commission explained, 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.[FN795]

Rehearing Requests

No requests for rehearing addressed this matter.

7. Hydroelectric Power

Non-Firm Transactions

In the Final Rule, the Commission explained that it 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.[FN796] This, the Commission indicated, should permit entities in a region to resolve concerns over the scheduling of non-firm hydropower.

Commission's Licensing Practices

The Commission explained that the issues raised by National Hydropower with respect to the Commission's hydroelectric licensing practices are beyond the scope of this rulemaking. The Commission also noted that these issues were raised in a petition to the Commission to revise hydroelectric licensing procedures, filed on July 10, 1995. That is the proper proceeding, the Commission explained, in which to address the Commission's hydroelectric licensing practices.

Rehearing Requests
No requests for rehearing addressed this matter.

8. Residential Customers
In the Final Rule, the Commission stated that it was convinced that the proposed changes for wholesale markets will benefit residential consumers. [FN797] Moreover, the Commission explained that the Rule does not require retail transmission access for retail customers of any size and does not require any changes in programs such as assistance to low-income and elderly consumers and weatherization and energy conservation, which are, and will remain, under the jurisdiction of the individual states. The Commission further noted that the 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.

Rehearing Requests
No requests for rehearing addressed this matter.

9. Miscellaneous Issues

Unconstitutional Taking of Property
Union Electric declares that the imposition of an onerous regime of mandates governing what utilities must and must not do with their own property constitutes an unconstitutional taking of their property in violation of the takings clause. ***12433**

Commission Conclusion
Union Electric has provided no valid legal or factual basis to support its arguments that our final orders result in an unconstitutional taking of property in violation of the takings clause. We have a statutory obligation under the FPA to remedy undue discrimination in the transmission or sale of electric energy subject to our jurisdiction. In Order No. 888, we concluded that unduly discriminatory and anticompetitive practices exist today in the electric industry and that such practices will increase as competitive pressures continue to grow in the industry.[FN798] Accordingly, we exercised our remedial authority by issuing Order Nos. 888 and 889 to ensure that unduly discriminatory practices can no longer occur.[FN799]

In exercising our remedial authority, we did not alter the traditional principle that a utility is entitled to a reasonable opportunity to recover its prudently incurred costs.[FN800] Union Electric has provided no evidence that it will not be adequately compensated for whatever services it may provide on its system following the effectiveness of Order Nos. 888 and 889. To the extent a third party uses Union Electric's transmission system, it must still compensate Union Electric for that usage, as has happened in the past. There simply cannot be an unconstitutional taking of property when public utilities continue to have the right to file for and receive rates that provide them a reasonable opportunity to recover their prudently incurred costs. Indeed, as the Supreme Court has explained, "[a]ll that is protected against, in a constitutional sense, is that the rates fixed by the Commission be higher than a confiscatory level." [FN801] Union Electric has made no showing that Order Nos. 888 and 889 will result in its rates being set at a confiscatory level. Furthermore, the rate that Union Electric may charge for transmission service is currently before the Commission in Docket No. OA96-50-000 and Union Electric should make arguments regarding the reasonableness of its transmission rate in that proceeding. [FN802] Moreover, Union Electric is free to propose changes to the rate it charges for transmission from time to time to ensure that it is being fairly compensated for its investment in its transmission system, as well as any expenses it incurs in providing such service.

Section 206 Complaints

Cleveland states that, unfortunately, it has suffered significantly because of denied transmission access and the inefficacy of long-delayed enforcement relief under section 206 of the FPA. Thus, Cleveland states that the Commission must announce its intention to enforce transmission and related obligations and, having made that pronouncement, take whatever steps are necessary to do so.

TAPS states that throughout the Final Rule the Commission points to complaint procedures to redress complaints against transmission providers' open access tariffs and argues that the Commission must clarify that these complaints will receive expedited treatment.

Commission Conclusion

The Commission has a statutory obligation to act if it finds, upon its own motion or upon complaint, that any rate, charges, or classification demanded, observed, charged, or collected by any public utility, or that any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory or preferential, and to determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed. Moreover, section 206(b) of the FPA requires that whenever the Commission institutes a proceeding under this section it must establish a refund effective date. In carrying out its obligations under section 206 of the FPA, the Commission acts as expeditiously as is possible, given the complexities of the issues at hand, its other workload and its level of staffing. The Commission will continue to work as expeditiously as possible in resolving section 206 proceedings, as well as in resolving all of the other matters that come before it. Given the critical importance of timely, comparable transmission access in fostering competitive wholesale power markets, the Commission intends to vigorously enforce utilities' open access obligations.[FN803]

We would emphasize that filing complaints with the Commission is not the only avenue that transmission customers (or potential customers) can pursue to raise their concerns. Under the Open Access Transmission Tariff, parties can and should avail themselves of the Dispute Resolution Procedures set forth in section 12 of the pro forma tariff. This section provides that an arbitrator must render a decision and notify the parties within ninety days of appointment.

NRC Remedial Orders

Cleveland asks that the Commission clarify that directives requiring non-discriminatory treatment of transmission customers are not intended to override, but are expected to accommodate, valid remedial orders of the NRC imposed in the form of nuclear license conditions. ***12434**

Commission Conclusion

We will deny Cleveland's requested clarification because it is overly broad. However, we do clarify that we view our jurisdiction under the FPA and the NRC's jurisdiction as complementary. In that regard, a utility subject to the Commission's jurisdiction and to the NRC's jurisdiction would have to comply with the orders of both commissions. Moreover, just as the NRC cannot and does not enforce this Commission's orders, it is not within our jurisdiction to enforce orders of the NRC. In the event that an entity believes that it must, but cannot, comply with separate orders issued by this Commission and the NRC, it should present evidence to this Commission and/or the NRC of such a conflict. To the extent necessary and appropriate, we would attempt to resolve any such conflicts subject to our jurisdiction under the FPA.

Retail Customers' Future Access to Transmission Capacity

IL Industrials states that the Commission should fashion safeguards to prevent monopolization of transmission capacity by wholesale customers before retail customers are entitled to engage in direct access. Alternatively, IL Industrials states that the Commission should specify that this issue will be addressed in the CRT NOPR proceeding and that contracts or other arrangements affecting available transmission capacity will be subject to safeguards to protect retail customer transmission access.

Commission Conclusion
This matter is beyond the scope of this proceeding. We have no way of ascertaining the transmission capacity that a retail customer may require in the future should it become entitled to engage in direct access through a state-approved program or voluntary action by its current transmission provider. We cannot require a transmission provider to keep transmission capacity available for all possible transactions that a retail customer may possibly enter into in the future. Just as transmission customers must take the system as it exists at the time of a request, so must future potential transmission customers take the system as it exists at the time of their request.

Transaction Accommodation Arrangements
NCMPA argues that the Commission failed to address the problem of market power arising from a transmission provider's control over transaction accommodation arrangements, which it states are arrangements needed by transmission dependent utilities to accommodate third-party transactions within an existing power supply relationship between the TDU and the transmission provider. NCMPA explains that this problem is most apparent where there is a comprehensive power supply relationship that purports to establish most or all of the TDU's bulk power needs. For example, NCMPA points out that because of Duke Power Company's control over transaction accommodation arrangements, NCMPA has been frustrated in its attempts to pursue beneficial bulk power transactions with parties other than Duke. NCMPA asks that the Commission require transmission providers to provide these arrangements on a comparable basis, state that it will take prompt action to remedy a denial of comparable arrangements, and require that any utility seeking specific permission for any action premised on the mitigation of market power to demonstrate that it has offered comparable transaction accommodation arrangements to any TDU that requires such arrangements.

Commission Conclusion
NCMPA's concerns appear to be related to its existing power supply arrangements, not with new service under the pro forma tariff. These concerns are more appropriately addressed in a case-specific section 206 complaint proceeding before the Commission.

Ohio Valley—Power to Uranium Enrichment Facility
Ohio Valley asks the Commission to clarify that the orders do not apply to Ohio Valley so that Ohio Valley can continue to provide the lowest possible cost, and most reliable, service to the Piketon, Ohio uranium enrichment facility owned by the United States.[FN804] Otherwise, Ohio Valley argues, compliance could result in increased costs to the United States and to the customers of the utilities participating in providing power to the enrichment facility. Ohio Valley seeks to avoid unnecessary interference with its ability to carry out its obligations under the existing agreements, but is amenable to reasonable and prudent use of its transmission system in accordance with sections 211 and 212.[FN805]

Commission Conclusion
Ohio Valley's rehearing request is essentially an application for waiver that is not properly addressed in this proceeding. By order issued July 2, 1996, we explained that because of the fact-specific nature of waiver requests the Commission will not address such requests in a generic rulemaking proceeding, but will require entities seeking waiver to submit separate, fact-specific requests that will be docketed in separate OA proceedings.[FN806] Subsequently, Ohio Valley filed a separate petition for waiver in Docket No. OA96-126-000 that effectively reiterated the arguments made in its rehearing request. The Commission will address Ohio Valley's fact-specific arguments in Docket No. OA96-126-000.

Exchanges

Several entities argue that exchanges should be permitted without a requirement that customers book capacity for each direction the power will flow and parties should not each have to pay the full reservation charge.[FN807] Because point-to-point customers can change receipt points without payment of additional charges, they argue that the same logic applies to exchanges.

Commission Conclusion

An exchange between two utilities has traditionally been viewed as two separate transactions (two one-way services) from the transmitting utility's planning and reservation perspective and has been priced as two separate services. Consistent with this approach, the pro forma tariff only allows changes to points of receipt and delivery for point-to-point service on a non-firm basis at no extra charge. Any changes to points of receipt and delivery on a firm basis must be submitted to the Commission as new applications. However, we note that comparability is achieved if the transmission provider charges itself and its transmission customers for point-to-point service on a consistent basis, whether that be separately for both directions or on a bidirectional basis.

Various Rate Matters

VT DPS and Valero argue that rates "should be based on a definition and quantification of a core of transmission function lines and substations for use in wholesale wheeling rather than on the basis of a rolled-in rate for the entire ***12435** transmission network." VT DPS states that "[i]n order to insure against cross subsidization, the tariffs should provide for the imposition of a Local Transmission System Access Charge to recover the costs of the facilities used to provide service to customers in this category." (VT DPS at 23-24; Valero at 8-10).

American Forest & Paper argues that the Commission's proposal includes as part of the transmission revenue requirement amounts attributable to the utility's use of its own transmission system to effectuate off-system sales and revenues received from transmission customers taking service under existing contracts and tariffs but not under the new transmission tariffs. By failing to subtract such revenues from the revenue requirement used to determine rates for services rendered under the new tariffs, the utility effectively recovers these amounts twice: once from its off-system sales and transmission customers not taking service under the new tariffs and a second time from its customers taking service under the proposed new tariffs."[FN[808]]

American Forest & Paper asserts that to eliminate this double-recovery, the Commission should adopt PacifiCorp's proposal in Docket No. ER95-1240. American Forest & Paper further declares that the Commission must demonstrate that the charges imposed on customers of network wheeling service are commensurate with the benefits that they receive.

Commission Conclusion

We are not prepared to mandate in a generic proceeding such as this that all transmission rates must be established by function or that a specific pricing methodology should be used. Our rate policy, as set forth in the Transmission Pricing Policy Statement, is to encourage flexible and innovative rate approaches by the electric industry. Mandating a single methodology for the entire industry would certainly defeat that goal. While the Commission welcomes new and innovative proposals, we will not impose a generic change in this proceeding. As always, utilities are free to propose the use of a functional pricing method in their compliance filings or in any section 205 filing it may submit to the Commission.

Federal Government Contract Clauses

ConEd asserts that the Commission must modify the pro forma tariff to include certain Federal government required anti-discrimination clauses. According to ConEd, these clauses require that all of Con Edison's transmission providers agree to be bound by certain provisions of the federal subcontractor regulations. ConEd suggests that the "Commission state that Con Edison and similarly-situated utilities be permitted to comply with the federal subcontracting requirements by inserting such clauses in their service agreements for transmission services." (ConEd at 17-18).

Commission Conclusion
The Commission disagrees with ConEd's assertion that the Commission must modify the pro forma tariff to include certain Federal government anti-discrimination clauses. The Commission does not dispute that certain parties must comply with provisions of the federal subcontractor regulations for particular transactions that may involve the provision of transmission service. However, we do not agree that these provisions must be incorporated into the pro forma tariff. The contracting obligation raised by ConEd is independent of the pro forma tariff and more appropriately addressed in a separate contract between the parties to the purchase or the service agreements for transmission services. The Commission notes that this is apparently how the issue has been handled in the past by ConEd because its tariffs previously filed with the Commission (pre-NOPR) did not include such anti-discrimination clauses.

V. Environmental Statement

Summary
The Commission prepared an environmental impact statement (EIS) to evaluate the environmental consequences that could result from adopting the Rule. We did so largely in response to the claims of several commenters who charge that the Rule will have significant adverse environmental effects. As described in Order No. 888:

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 controls on nitrogen oxides (NO_X) emissions. 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.[FN[809]]

The EIS recognizes that the electric industry will contribute to air emissions regardless of whether the Rule is adopted. The purpose of the EIS is to analyze to what extent the Rule is likely to affect those emissions.

Many variables can influence the impacts of the Rule and the EIS uses a modeling framework that incorporates a range of assumptions about these variables. The most significant variable is likely to be the future prices of the two primary fuels used to generate electricity—coal and natural gas. Government and industry price forecasts were used to construct two alternative fuel price assumptions: (1) that the price of natural gas will increase relative to the price of coal; and (2) that the relative price of coal and natural gas will remain constant. These assumptions form the basis for two base cases that project the environmental impacts of developments in the electric industry without the Rule. The EIS then makes assumptions about the effects of the Rule to create three scenarios that project a range of possible results. It compares the environmental impacts projected in the scenarios with those projected in the base cases to determine the effect of the Rule.[FN810] The analysis set forth in the EIS demonstrates that the Rule will not in any significant respect affect overall trends in NO_X emissions.

Subsequent to the issuance of Order No. 888, the Environmental Protection Agency (EPA) conducted a review of the Commission's FEIS in which EPA employed alternative assumptions for a number of model inputs. In doing so, EPA stressed that "[n]aturally there can be differences among reasonable analysts concerning the assumptions used in such an analysis" and that "EPA believes the assumptions used by the FERC and those used by EPA both lie within the reasonable range."[FN811] EPA has concluded that the Rule is unlikely to have any significant adverse environmental impact in the immediate ***12436** future, and that implementation of the Rule should go forward without delay. In reaching these conclusions, EPA concurred that the Commission conducted an adequate NEPA analysis of the environmental impacts of the Rule under a range of possible scenarios. EPA also agreed that the Commission made a reasonable choice of models with which to conduct the analysis and, as noted above, made assumptions for various factors input into the model that lie within the range of reasonable assumptions.

EPA also concurred with the Commission that NO_X emissions increases associated with the Rule, if any, should be addressed as part of a comprehensive NO_X emissions control program developed by EPA and the states pursuant to the Clean Air Act. EPA committed to use its Clean Air Act authority to support successful completion of this program, and stated that it will establish a NO_X cap-and-trade program through Federal Implementation Plans if some states are unwilling or unable to act in a timely manner.

In a letter dated May 13, 1996, the EPA Administrator referred Order No. 888 to CEQ.[FN812] In doing so, EPA suggests that if the Ozone Transport Assessment Group (OTAG) and Clean Air Act processes fail to produce the necessary pollution limitations in a timely manner, EPA will call upon all other interested federal agencies to assist in solving the problem. EPA would ask the Commission to contribute by examining, through a Notice of Inquiry, possible strategies for mitigating NO_X emissions increases associated with the Rule.

The Commission subsequently responded by issuing an order stating that if EPA concludes that the OTAG process has not succeeded in meeting its objectives in a timely manner, the Commission would initiate a Notice of Inquiry to further examine what mitigation might be permissible and appropriate under the Federal Power Act. Such an inquiry would solicit public comment on how to assess appropriately the air pollution impacts attributable to the Rule, suitable ways in which to address such impacts, if any, and the scope of the Commission's authority to address such impacts. The Commission also stated that, under the extraordinary circumstances in which EPA would undertake a Federal Implementation Plan, the Commission would agree to initiate contemporaneously a rulemaking to propose possible mitigation that could be undertaken by the Commission under the FPA. Such a rulemaking would be undertaken on the basis of the Notice of Inquiry discussed above and would be appropriate only if environmental harm attributable to the Rule that warranted mitigation is demonstrated.[FN813] On June 14, 1996, CEQ concluded that the Commission's order was fully responsive to EPA's concerns and requests and that the referral process and corresponding responses to the referral from the Commission and other agencies have successfully resolved the disagreements between EPA and the Commission.[FN814]

As discussed below, EPA is currently taking steps to implement a comprehensive NO_X emissions control program to ensure that emissions reductions are achieved to prevent significant transport of ozone pollution across state boundaries in the Eastern United States. OTAG is continuing to work in conjunction with EPA on this issue and intends to complete its process in the near future.

Rehearing is sought on eight categories of issues relating to the Commission's analysis of environmental issues: selection of the appropriate no-action alternative; challenges to modeling assumptions; need for mitigation; emissions standards disparity; the short-term consequences of the Rule; cost benefit analysis; socioeconomic impacts; and compliance with the Coastal Zone Management Act. For the reasons discussed below, rehearing is denied.

A. The Appropriate No-Action Alternative

The FEIS discusses several alternatives, including the alternative of instituting open access pursuant to section 211 of the FPA. The FEIS states in this regard that:

Actions taken pursuant to section 211 and pursuant to sections 203 and 205 in merger and market-rate cases, respectively, represent a case-by-case approach to establishing open access. Absent action on the proposed rule, the Commission would continue using these authorities to require utilities to file open access tariffs and provide case-specific service, as necessary or appropriate. In addition, sections 205 and 206 charge the Commission with ensuring that purely voluntary transmission tariffs are not unduly discriminatory. Thus, if the proposed rule were not adopted, the Commission would continue to require that voluntary tariffs be upgraded to offer the Commission's current standards for non-discriminatory open access transmission services. The result of continuing the Commission's policies without the proposed rule is that the Commission would effectuate a more open transmission grid, but in a patchwork manner and at a slower pace.

The case-by-case approach to achieving open access currently in use is slower and more costly, and thereby less desirable, than the generic approach set forth in the proposed rule. Thus, the no-action alternative is not a reasonable alternative to the proposed rule.[FN815]

Rehearing Requests

The PA Com contends that the FEIS does not adequately consider the alternative of instituting open access pursuant to section 211 of the FPA. It states that section 211 provides a means for wholesale power sellers and buyers to obtain transmission services necessary to compete in, or to reach competitive markets, and that the FEIS ignores the steady, if slow, progression to open access taking place under section 211.

Commission Conclusion

The FEIS notes that there are significant reasons for implementing open access through a rulemaking rather than the case-by-case approach of section 211. In the absence of a Commission rulemaking, the development of open access pursuant to section 211 would occur as potential transmission users file requests for such services and the Commission approves them as appropriate. Such proceedings are likely to be contested by competitors and the Commission would decide each application individually. Given the number of potential transmission users who are likely to file requests for such services, it is conceivable that this approach may require the Commission to decide a large number of such applications. [FN816] Thus, the case-by-case approach is likely to be much slower and more costly to implement than action by rule.

Case-by-case implementation of open access is also more likely to result in patchwork development as the policy evolves over time. It is important to develop uniform national standards to facilitate the move to open access. This approach adds certainty and facilitates development and implementation of open access in a way that would be difficult to achieve on a case-by-case basis. The development of national ***12437** standards is best done through a mechanism whereby all interested parties can participate in shaping the policy through notice and comment rulemaking. The piecemeal implementation of open access on a case-by-case basis over time, no matter how carefully conducted, is likely to result in inconsistencies and difficulty in application. Given the national nature of the electric grid and the developing open access market, case-by-case implementation is not practical nor desirable and will limit the anticipated benefits of open access.

The PA Com does not specify how the Commission fails to adequately consider the alternative of instituting open access pursuant to section 211. It is insufficient for a party to complain that an analysis is inadequate without providing specific support for its claim. As the court noted in Northside Sanitary Landfill, Inc. v. Thomas, 849 F.2d 1516, 1519-20 (D.C. Cir. 1988), cert. denied, 489 U.S. 1078 (1989):

In Vermont Yankee Nuclear Power Corp. v. Natural Resources Defense Council, Inc., 435 U.S. 519, 98 S.Ct. 1197, 55 L.Ed.2d 460 (1978), then-Justice Rehnquist expressed the unanimous opinion of seven members of the Supreme Court that a party * * * has the burden of clarifying its position for the [agency]. Even though the [agency] has the statutory obligation to consider fully significant comments, "it is still incumbent upon intervenors who wish to participate * * * to structure their participation so that it is meaningful, so that it alerts the agency to the intervenors' position and contentions." 435 U.S. at 553, 98 S.Ct. at 1216. Justice Rehnquist, then quoted with approval Judge Leventhal's remarks in Portland Cement, id., and concluded that administrative proceedings should not be a game or a forum to engage in unjustified obstructionism by making cryptic and obscure references to matters that "ought to be" considered and then, after failing to do more to bring the matter to the agency's attention, seeking to have that agency determination vacated on the ground that the agency failed to consider matters forcefully presented."

Id., at 533-54, 98 S.Ct. at 1217.

We also note that the PA Com's quarrel does not appear to be with the Commission's analysis of the section 211 alternative in any event, but rather with the underlying policy decision to implement open access through a rulemaking rather than more slowly on a case-by-case basis.

The Administrative Procedure Act authorizes agencies to establish policies by rulemaking or on a case-by-case basis. Here, the Commission has properly exercised its discretion to establish open access by rulemaking rather than in individual proceedings. The PA Com does not contest this authority or the Commission's exercise of it. Rather, its complaint goes to the underlying policy choices guiding that decision. Disagreement with an agency's policy choice is not a proper basis for a NEPA-based challenge to agency action. As the Circuit Court of Appeals for the District of Columbia (D.C. Circuit) stated in Foundation on Economic Trends v. Lyng, 817 F.2d 882, 886 (D.C. Cir. 1987) (footnote omitted) (brackets in original):

NEPA was not intended to resolve fundamental policy disputes. As the Supreme Court recently admonished, "[t]he political process, and not NEPA, provides the appropriate forum in which to air policy disagreements." Metropolitan Edison Co. v. People Against Nuclear Energy, 460 U.S. 766, 777, 103 S.Ct. 1556, 1563, 75 L.Ed.2d 534 (1983) (citation omitted). A policy disagreement, at bottom, is the gravamen of appellants' complaint. In our view, "[t]ime and resources are simply too limited for us to believe that Congress intended to extend NEPA as far as [appellant would take] it." Id. at 776, 103 S.Ct. at 1562. [FN[817]]
Contrary to the PA Com's assertion, and regardless of the basis for that assertion, the discussion of the section 211 alternative in the FEIS satisfies the requirements of NEPA. The Supreme Court has stated that "[t]o make an impact statement something more than an exercise in frivolous boilerplate the concept of alternatives must be bounded by some notion of feasibility." [FN818] "Central to evaluating practicable alternatives is the determination of a project's purpose." [FN819] "The range of alternatives that must be considered in the EIS need not extend beyond those reasonably related to the purposes of the project." [FN820] The purpose of the Rule is to implement open access in order to remedy undue discrimination and to do so on a timely basis and in a uniform manner; the Commission has determined that case-by-case implementation of open access will not satisfy that purpose.

The PA Com has proffered no reasons why the examination in the FEIS of the section 211 alternative is insufficient. We conclude that the FEIS adequately considers the alternative of instituting open access pursuant to section 211. Rehearing on this issue is denied.

B. Challenges to Modeling Assumptions

Several rehearing requests challenge the modeling assumptions used in the FEIS. These challenges are raised in support of the claim that the Commission's analysis understates the environmental impacts of the Rule. The most fundamental challenge is the PA Com's claim that computer modeling is insufficient to examine the impacts of the Rule. The PA Com and Joint Commenters suggest that the model fails to use the appropriate base case. Questions are also raised regarding specific assumptions used in the model.

In discussing these issues below, we note that although EPA raised many similar points with respect to the Commission's modeling approach in comments on the DEIS, EPA ultimately concluded that "the FERC has conducted an adequate analysis under the National Environmental Policy Act of the environmental impacts of the open access rule under a range of possible scenarios" and that "[t]he FERC made a reasonable choice of models (CEUM) and made assumptions for various factors input into the model that lie within the range of reasonable assumptions." EPA also notes that the Commission performed the specific additional analyses that were requested in comments on the draft EIS.

As EPA points out, "[n]aturally, there can be differences among reasonable analysts concerning the assumptions used in such an analysis." EPA then reiterates that it believes that assumptions used by the Commission "lie within the reasonable range." It concludes that "the FEIS provides a credible basis for understanding the possible environmental impacts of the open access rule."

1. Appropriate Base Case

Selection of the appropriate base case was contested in the DEIS on grounds similar to those presented here. Certain commenters argued that the Commission should compare the impacts of the Rule to a no-action alternative that assumes that the Commission abandons all open access policies, not just the Rule. Some commenters went even further, suggesting that the Commission compare emission levels projected to result from the Rule against a frozen efficiency case in which other major ***12438** factors—factors that would increase industry efficiency independent of the Rule—do not occur. Such factors include adoption of pro-competitive state polices and actions by utilities to undertake mutually beneficial voluntary transactions that do not require the use of open access tariffs mandated under the Rule. Commenters who advocated either a different no-action alternative or the frozen efficiency case posited that studies using those assumptions would show that the Rule will cause significantly greater NO_X emissions than those shown in the DEIS. We concluded in Order No. 888 that:

[S]taff 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 * * * 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. [FN[821]]]

Rehearing Requests

Pennsylvania PUC. The PA Com asserts that the Commission did not compare emissions levels associated with the Rule against the appropriate base case. It claims that the Commission should have used continued case-by-case evolution of open access and increased wholesale competition under FPA sections 211 and 212 as the base case instead of generic, simultaneous, nationwide open access as mandated by Order No. 888. Put differently, the PA Com claims that the appropriate base case is the evolution of competition and open access without the intervention of Order No. 888. The PA Com concludes that by using the improper base case the FEIS ignores evidence of significant NO_X increases resulting from the Rule, which affects the ability of Pennsylvania to meet the mandates of the Clean Air Act.

Joint Commenters. The Joint Commenters maintain that the FEIS uses an inappropriate no-action alternative as a basis for analysis. [FN822] The gist of its argument is that the Commission must acknowledge the policy initiative of which it contends Order No. 888 is only one part. It claims that the Commission ignores the fact that, whether competition is pursued through Order No. 888 or on a case-by-case basis, implementation of open access is a major programmatic policy choice the environmental impacts of which must be addressed. It contends that by using case-by-case implementation as the no-action alternative, the Commission effectively defines away most of the impacts of the Rule.

In short, the Joint Commenters claim that by defining the no-action alternative as implementation of the open access program over a longer period of time through case-by-case action, the Commission did not fully examine the potential impacts of Order No. 888. It states that if the effects of Order No. 888 are defined to include only those that result from the timing difference between implementation of open access through case-by-case decisions and open access pursuant to a generic rule, it is virtually a foregone conclusion that most of the potentially adverse environmental effects of the Commission's open access policies will not be identified.

The Joint Commenters concur that the frozen efficiency case analyzed in the FEIS is a proper starting place for an acceptable NEPA review. It faults the discussion of the frozen efficiency case, however, as failing to provide important information needed to allow parties to evaluate the analysis. The Joint Commenters complain that the analysis does not include the model outputs which demonstrate the most severe environmental effects; this, they claim, makes it impossible to verify the results or analyze the factors contributing to the effects shown.

The Joint Commenters state that in addition to omitting the modeling outputs for the most environmentally relevant cases, the FEIS does not contain air quality modeling of the scenarios that show the greatest emissions increases. It claims that the Urban Airshed Model (UAM-V) examines only the incremental impacts of the Competition-Favors-Coal Scenario as compared with the High-Price-Differential Base Case, the same analysis presented in the DEIS. The Joint Commenters stress that EPA in its comments on the DEIS noted that the results shown for this case (an emissions decrease) is illogical and should be explained. It states that without modeling the emissions changes associated with the Competition-Favors-Coal Scenario over the frozen efficiency base case, the FEIS provides no indication of the seriousness of the environmental harm from potential emissions increases caused by FERC's initiatives. The Joint Commenters also claim that the expanded transmission analysis used in the FEIS is unduly conservative.

Commission Conclusion

The Commission continues to believe that the base cases and scenarios used in the DEIS are most appropriate for studying the effects of the Rule. Nonetheless, to ensure that the effects of the Rule were analyzed fully, the FEIS also examined a frozen efficiency case that uses a combination of assumptions most likely to show significant increases in emissions.

We did this despite our belief that it is inaccurate to attribute all efficiency improvements in the industry to Order No. 888 or even to federal actions of all kinds. In fact, as noted in the FEIS, the frozen efficiency case is far more extreme in its assumptions than would be reasonable for a no-further-Commission-action case because it presumes that industry and state regulators also cease all changes toward a more competitive industry. However, the frozen efficiency case is useful as a sensitivity analysis because it reflects an extreme bound on any separate no-further-Commission-action case. [FN823] A fortiori the impact actually to be expected from the Rule must be less than that determined using the frozen efficiency case.

We believe that the frozen efficiency analysis is highly implausible because its represents a world in which: (1) the Commission reverses current pro-competitive transmission policies (inconsistent with congressional mandates under EPAct); (2) states cease to adopt programs to improve industry efficiency; and (3) electric companies cease to improve operation or to enter into mutually beneficial transactions.

The Joint Commenters agree that the frozen efficiency analysis constitutes a valid NEPA review. That issue, therefore, is not in dispute. It objects that the FEIS does not include the model outputs for the sensitivity cases which demonstrate the most severe environmental effects, and that it is therefore impossible to verify the results or analyze the factors contributing to the effects shown.

The Joint Commenters' assertion is incorrect. Appendix K of the FEIS sets forth tables demonstrating the results of ***12439** the model runs for the sensitivity analysis. These tables provide adequate documentation to analyze and verify the conclusions reached in the FEIS. We note also that the Joint Commenters have not requested specific model outputs that it claims are lacking. The Commission will make available information used in the study that Joint Commenters or anyone else identifies as not being provided.

As to the claim raised by the PA Com, it appears to be mistaken regarding the base case actually used in the FEIS. Contrary to what the PA Com states, the base cases do include continuing case-by-case actions under section 211 and the Commission's open access policy.

2. Challenge to the Use of Computer Modeling

The Commission's intent to use computer modeling in the identification and evaluation of the impacts of the Rule has been clear since the Commission decided to prepare an EIS. The DEIS and FEIS explain the computer modeling techniques used in the analysis in great detail.

For example, the DEIS and FEIS explain that the Coal and Electric Utilities Model (CEUM) was selected for the analysis because it is the best tested, most widely used national-level model available. [FN824] CEUM is a forecasting model that incorporates virtually all coal and electric utility market activities—ranging from mining, transportation, and blending of coal to power plant and system dispatching, transmission, and new capacity construction. It also examines the impact of changes in factors such as plant availabilities, heat rates, planning reserve margins, and transmission costs. CEUM has been used extensively by, among others, EPA and DOE.

CEUM models the contiguous United States as 45 separate demand regions. It possesses a supply component which models key coal supply regions and coal transportation networks in great detail. It also incorporates constraints on long-term coal supplies, power plant emission limitations, national emission caps (e.g., acid rain requirements of Title IV of the Clean Air Act Amendments of 1990), coal transportation capacity, electric transmission capacity, and power plant construction plans.

The DEIS and FEIS explain that to analyze the Rule, assumptions as to factors such as electricity demand growth rates, oil and gas prices, and planning reserve margins were developed and incorporated into the model. Factors such as existing patterns of transmission capacity and costs were also analyzed and incorporated into the model.

Once the necessary information and assumptions were incorporated into CEUM, model runs were conducted to ensure that the projections closely match actual experience for a selected year, in this case 1993. These runs used the information prepared for the base cases together with other inputs (e.g., electricity demand) for the historical year. The purpose of this calibration process was to ensure that the model replicates historical experience. After the model was calibrated, it was run for each of the base cases, and then for each of the Rule scenarios for selected time periods.

To examine the impact of the Rule on regional attainment of ozone standards, additional air quality modeling was conducted using the UAM-V. UAM-V is a three-dimensional photochemical grid model that simulates the physical and chemical processes in the atmosphere that affect pollutant concentrations. It tracks emissions both geographically according to preset weather patterns and chemically over time. The UAM-V was used to create detailed air quality analyses for cases that might potentially create additional impacts from NO_X transport and ozone in the Northeast.

Rehearing Requests

The PA Com challenges the ability of computer modeling to simulate the effects of the Rule. It states that computer modeling is an attempt to reflect an approximation of reality that uses systems of linear equations, and that the airborne transport of pollutants in the atmosphere and the North American electric transmission grid are extremely large, complex nonlinear systems.[FN825]

The PA Com's challenge to the use of computer modeling also turns on the observation that models produce results that are dependent on the inputs and assumptions used in the models. The specific challenges to the inputs and assumptions used in the model are discussed separately below.

Commission Conclusion

We note first that computer models are the only available means of analysis that incorporate the range of factors that influence engineering and economic choices in the electric power industry, and the atmospheric chemistry and weather patterns that influence downstream air quality. We are mindful of the limitations of models, but the alternative of using no model at all—and hence making no analytic attempt to capture the complex economic and environmental factors—did not appear reasonable.

The PA Com does not explain how the Commission should otherwise simulate the effects of the Rule. Computer modeling may not be a perfect tool, but it is the best existing mode of analysis for this type of effort. The PA Com cannot merely assert that such modeling is inadequate. As the court noted in a similar context in City of Los Angeles v. National Highway Traffic Safety Administration, 912 F.2d 478, 488 (D.C. Cir. 1990), overruled in part on other grounds, Florida Audubon Society v. Bentsen, 94 F.3d 658 (D.C. Cir. 1996):

Petitioners call for more "analysis," but do not specify what they see as lacking or how "analysis" could supply the want. At some point—here after a seemingly full treatment—the agency must make a judgment. We discern no more from petitioners' argument than that they disagree with that judgment. Even were we to share their view of the matter, that would not be a sufficient basis for overturning the agency's decision.

Quoting Portland Cement Ass'n v. Ruckelshaus, 486 F.2d 375, 394 (D.C. Cir. 1973), cert. denied sub nom. Portland Cement Ass'n v. Administrator, EPA, 417 U.S. 921, 94 S.Ct. 2628, 41 L.Ed.2d 226 (1974), the court in Northside Sanitary Landfill, Inc. v. Thomas, 849 F.2d 1516, 1519 (D.C. Cir. 1988), cert. denied, 489 U.S. 1078 (1989), stated in like manner that:
[C]omments must be significant enough to step over a threshold requirement of materiality before any lack of agency response or consideration becomes of concern. The comment cannot merely state that a particular mistake was made * * *; it must show why the mistake was of possible ***12440** significance in the results [the agency reaches]. (Emphasis in original).

The FEIS explains the Commission's conclusion that the environmental analysis of Order No. 888 is best conducted using the CEUM and UAM-V computer models. The PA Com cannot merely state that the use of such models is inappropriate. It must explain why this is so and what alternative method of analysis should be used. This it has not done. The request for rehearing is denied.

3. Transmission Assumptions

The FEIS recognizes the interdependence of interregional electric transmission transactions; accordingly, non-simultaneous interregional transfer capabilities estimated by the North American Electricity Reliability Council (NERC) were reduced for use in the model (see FEIS section 3.4.2). The analysis also considers the impact of the Rule on interregional transfers (see FEIS Tables 5-13 and 5-14), and the impact of changes in transmission capacity through sensitivity analysis.[FN826]

Rehearing Requests

The PA Com asserts that transmission usage in the FEIS is based on assumptions which are indeterminate to some degree. It states that historical interregional power transfers are used to estimate future transmission capabilities and capacity, and that while historical interregional electric transmission transactions have been large and complex, under the Rule the level of transactions will increase enormously. The PA Com claims that almost every time a new major interregional electric transmission transaction has occurred, there have been unpredictable flows of electricity in other regions that might be a thousand miles away. It concludes that relatively small changes in transmission flows can and have produced large harmonic transients and instabilities on the power grid.

The PA Com also contends that the relationship between the transmission usage price and the price of transmission service is unclear. It states that the development of the usage price seems circular, at least in part. It notes that model inputs were changed until the usage price coincided with an estimate of historical costs. The PA Com requests clarification of the development of the usage price assumption.

Commission Conclusion

The PA Com does not appear to understand the way the transmission usage price functioned in the analysis.[FN827] As explained in the FEIS, the CEUM model is annual and regional: it models a single year at a time using regions approximately the size of a state or large regions within a state.[FN828] Transmission in the model is represented as movement of power from one region to another. The model attempts to satisfy the demand for electricity at lowest cost—if there were no limitations on the movement of power from one region to another, the model would always generate power at the cheapest source and move that power to meet the demand. This result would clearly be unrealistic, since sources of power are limited in their ability to reach demand by limitations in the intervening transmission network. The transmission network in CEUM is represented primarily by the limitations that the transmission grid places on the ability of power to move freely to meet demand.

To use CEUM to provide a reasonable representation of transmission requires balancing the different ways in which the transmission system imposes limits on the movement of power. Flows on links between regions are limited by three general parameters in the model: losses, variable costs, and constraints on the quantity of capacity or energy that can be transferred. Losses are generally small, and are typically kept fixed from one model run to the next. Simulating transmission limits is largely a matter of balancing variable costs and quantity limits. True variable costs are usually assumed to be small, reflecting the low variable cost of operating the transmission system. Basic quantity limits are usually developed from NERC sources or other studies of the limits imposed by the physical operation of the transmission system.

However, such limits do not always provide an adequate picture of current patterns of generation and transmission in the electric utility system. Movement of power from low cost sources is limited not only by the physical constraints of the transmission system, but also by institutional impediments such as lack of access to needed transmission. As a result, in a model like CEUM, where flows are based on minimizing costs subject to physical constraints, the amount of power flowing from lost-cost sources of generation is typically overestimated.

The FEIS explains that there are two primary ways to address this difficulty when calibrating the model to represent historical power flows. One is to impose further limits on the quantity of power transferred within the model. The other is to raise the variable cost to simulate the effect of observed barriers to power flows between regions. The second approach was used by developing a "usage price" to raise the variable cost barriers in CEUM and supplement basic quantity limits derived from NERC estimates. This approach was taken because of its nexus to the primary effect of the Rule on transmission activities. The primary effect of the Rule on transmission will be to increase the ability of transmission users to gain access to transmission service and to permit users to develop flexible ways for buyers and sellers to use the transmission system efficiently. The primary effect is thus to remove institutional barriers to the use of the transmission system—in effect to reduce the transaction costs, or usage price, faced by those seeking access to transmission. Thus, the model was calibrated by selecting an initial set of usage prices and adjusting those prices until the model provided an accurate representation of historical generation and transmission patterns.

Usage prices (in mills per kWh) were developed by running CEUM for a historical period (1993). Starting from initial estimates of usage prices between CEUM regions, the model was run using historical inputs for 1993; the outputs from these runs were compared with the historical pattern of generation and transmission for that year. Usage prices were then adjusted until the pattern projected by the model was consistent with the observed historical pattern. The final adjusted prices were then used as the current usage prices.

Two rules were used to set the initial usage price estimates:

(1) For closely coordinated (i.e., tight) pools, no separate usage price was assumed. This is consistent with the principle embodied in many pools that transmission ***12441** assets are to be treated as one system and used to minimize variable costs. Any allocation of the cost of service associated with transmission assets is typically treated as a fixed cost.

(2) Separate transmission costs are commonly applied in loosely configured pools. In many cases, these separate costs are derived on a MW-mile basis. Because the number of systems that have to be traversed within a loosely configured pool is generally small, the transmission usage price for areas with loosely configured pools were set to a small initial value (1 to 2 mills/kWh). Transmission across NERC regions may require traversing many utility systems, and for modeling purposes a charge of about 3 mills/kWh was assumed.

Applying this method required several runs of CEUM. Usage price changes were typically downward in areas where the initial prices were set at 3 mills per kWh, and prices after adjustment remained within the range of the initial usage prices. As a result, estimates of the current usage price varied from region to region after calibration, but generally fell within the range of 1 to 3 mills per kWh.

Thus, the concerns expressed by the PA Com were either considered in the FEIS, or are based on a misunderstanding of the method used.

4. Plant Availabilities and Heat Rates

The FEIS explains that power plant availability is the percentage of time that a generating unit is available to provide electricity to the grid, and that availability estimates for coal plants have an important effect on projected base case emissions because those estimates determine the amount of future generation expected from existing power plants.[FN829]

The base cases assume that average fossil-fuel plant availability rises to 85 percent by 2005 and then remains constant through 2010. This assumption reflects continuing efforts by utilities to improve plant availability. Between 1984 and 1993, coal plant availability increased five percent to nearly 81 percent. This trend is projected to continue through 2005 as electric generators respond to competitive pressures and opportunities extant without the Rule.

The FEIS explains that in the Competition-Favors-Coal Scenario, plant availabilities are assumed to reach 90 percent (as opposed to 85 percent in the base cases and other Rule scenarios) because competition is projected to lead to greater operational efficiency in generation markets. It notes that some older coal plants are not likely to reach this level without substantial capital investment. However, since 90 percent availability is achievable for many plants, this figure was selected as an upper bound to illustrate how much existing plants may be able to run if generation owners focus on meeting competition through greater use of coal plants.

The FEIS also explains that the base cases assume some deterioration in heat rates between life extension programs. In the Competition-Favors-Coal Scenario, existing generating plants are assumed to be better maintained so that there is no deterioration of heat rates between life extension programs. Except in the Competition-Favors-Gas Scenario, it is assumed that new combined cycle natural gas plants sustain existing heat rates (rather than improving as the next generation of gas technology comes on line). These assumptions reflect the fact that industry has put more effort into making better use of existing (disproportionately coal) plants rather than into improving the performance of new (almost entirely gas) plants.

Rehearing Requests

The PA Com challenges the plant availability assumptions used in the FEIS. It notes that the analysis assumes that generation plant availability will rise to 85 percent and that the Competition-Favors-Coal Scenario assumes that generation plant availability will rise to 90 percent by the year 2005. The PA Com states that although historical trends indicate that plant availability might increase, in reality as availability goes up it becomes increasingly difficult to obtain further improvements.

The PA Com contends that increasing availability to 85 percent would be surprising; an increase to 90 percent would be astonishing. It states that such increases would require a number of simultaneous technical advances, the likelihood of which are speculative. The PA Com argues that utilities in competition with each other may be less willing to fund and participate in cooperative research that leads to technical advances. The PA Com notes that maintenance staffs are being reduced as a result of cost reduction programs and that plant availability might decline as maintenance is deferred.

The PA Com also contends that the assumption in the Competition-Favors-Coal Scenario that heat rates do not degrade (go up) over time may be optimistic. It concedes that technological advances have produced dramatic improvements in heat rates, but states that it is unclear if this improvement is sufficient to overcome losses caused by backfitting emission control equipment. The PA Com notes that coal-fired generating stations in Pennsylvania have been required to install emission control equipment and that efficiency has been reduced in some cases, degrading the heat rate. It states that some coal stations have installed sulfur dioxide (SO_2) scrubbers which can reduce efficiency by five percent, and that other stations may be required to install selective catalytic reduction systems for NO_x or SO_2 scrubbers.

The PA Com contends that an additional limit on heat rate improvements is the age of generating stations and the fact that heat rates decline as stations age. It posits that this decline may be greater than the improvements that can be gained through technological advances.

Commission Conclusion

The PA Com's argument fails to consider the discussion of this issue in the FEIS.[FN830] Briefly, higher availabilities for coal plants were assumed in order to provide a scenario that was extremely favorable to the use of coal in existing facilities and hence a scenario that was most likely to have a larger environmental impact. The fact that some coal plants are able to maintain 90 percent availability is sufficient grounds for considering such a case, especially where the purpose of the assumption is to establish a reasonable range of potential environmental outcomes from the Rule.

With regard to the heat rate assumptions, the PA Com does not appear to understand how the assumptions functioned in the analysis. First, the factors it mentions (e.g., efficiency reductions resulting from the addition of scrubber technology) are already considered in the CEUM model. Second, the CEUM does assume that heat rates degrade over time in the base cases. The assumption that they do not degrade in the Competition-Favors-Coal Scenario was made to simulate the relative improvement that might be achieved through potential effects of the Rule when competition is favorable to coal. As with certain other modeling assumptions challenged by the PA Com on rehearing, the heat rate assumptions used by the Commission are more conservative than those urged by the PA Com and thus demonstrate greater impacts from the Rule than would be the case using the assumptions urged by the PA Com. ***12442**

5. Reserve Margins

The FEIS discusses the assumptions regarding planning reserve margins and their use in the model.[FN831] It states that planning reserve margins influence the amount of new capacity built and the mix of gas versus coal fired generation projected in CEUM. In particular, lower reserve margins tend to result in the construction of less capacity (typically, fewer gas-fired turbines and combined cycle units) and a somewhat greater utilization of existing coal units.

Generally, individual utilities set their reserve margins to comply with a technical standard established by the NERC sub-region. Typically, the NERC sub-region might determine that a one day in 10 years loss of load probability (LOLP) is the appropriate standard. Individual utilities within the sub-region would determine their reserve planning margin to be consistent with this standard after accounting for tie capabilities. NERC sub-regional studies are performed periodically to determine whether the reliability standard is being satisfied for the planning horizon given planned capacity additions. The tie capability between the sub-region and other regions is accounted for in reliability studies at the NERC sub-regional level.

The FEIS notes that in recent years, reserve margins typically have been revised downwards, although the planning standard itself (most commonly the one day in 10 years LOLP) has not been changed. Three reasons support the downward revision in reserve margins: (1) An expected improvement in unit availability; (2) anticipated shifts in utility load shape towards a lower load factor; and (3) an increase in the number of generating units.

FEIS Table 3-4 summarizes the reserve criteria and associated planning reserve margins that have been derived from the most recent annual planning documents prepared by the reliability councils. It states that a review of current planning documents shows that utilities expect planning reserve margins to decline over time. One factor identified as contributing to this decline is the expectation that availability will improve appreciably as utilities are subject to performance-based regulation and experience greater competition.

Additionally, some utilities have revised their planning reserve margins to account for ties in other regions. In some cases, utilities have updated their planning reserve margin calculation to reflect current estimates of customer willingness to pay for increase reliability.

Based upon a review of utility expectations, the FEIS concludes that an appropriate base case assumption is for planning reserve margins to decline by 2005 to the lower end of the applicable ranges set forth in FEIS Table 3-4.

Rehearing Requests

The PA Com challenges the reserve margin assumptions used in the model. It asserts that the assumption that reserve margins will fall to fifteen percent by 2000 and (in one scenario) to thirteen percent by 2005 is based in part upon the assumption of increased generation plant availability across the board. The PA Com notes that this increase in availability might not occur. It states that as wholesale transactions increase under open access, some, but not most, utilities will be able to reduce reserve margins and still maintain reliability. The PA Com asserts that many utilities cannot reduce reserve margins because available transmission capacity between regions is already being utilized to the maximum extent possible. It concludes that reserve margins for certain individual utilities could decline, but this alone would not reduce required reserve margins for all utilities to the levels that are assumed in the model.

Commission Conclusion

The reserve margins used in the base cases were set using current utility plans and trends in the industry. Reserve margins for the competition scenarios were set slightly lower, reflecting the potential for decline in a more open competitive environment. The PA Com acknowledges the potential decline, but claims that not all utilities will be able to reduce reserve margins to the levels assumed. However, the FEIS addresses such differences by using different regional assumptions about reserve margins and different reserve margins in each region. The PA Com's concern is therefore without basis.

6. Northeast MOU

The FEIS assumes that power plants in the Northeast Ozone Transport Region (OTR) will comply with Phase II of the Northeast Memorandum of Understanding (MOU). The MOU establishes NO_X tonnage limits during the five-month ozone season (May-September) for electric generating and large industrial services and allows for emissions trading.[FN832] The FEIS states that compliance with Phase III of the MOU was not assumed since its implementation is optional, depending on final attainment status with regard to Clean Air Act requirements.

Rehearing Requests

The PA Com states that the base cases and scenarios assume that no NO_X controls will be required for Title IV group II boilers, that phase II of the MOU will be implemented, and that no additional requirements will be imposed. The PA Com contends that phase III of the MOU might be implemented, and that if this occurs and upwind generation is not required to control ozone precursors, cleaner generation in the Northeast may be displaced by increased generation from outside the OTR.

Commission Conclusion

In essence, the PA Com appears to be raising an emissions disparity argument rather than posing a challenge to the modeling assumptions used in the FEIS. The emissions disparity argument is addressed below.

7. Natural Gas Prices

Average wellhead natural gas prices for the High-Price-Differential Base Case were based on a recent forecast of natural gas acquisition prices by Wharton Econometric Forecasting Associates (WEFA).[FN833] This forecast projected at that time that natural gas prices would increase in real terms (1994 dollars) to $1.83 per MMBtu by 2000, and rise to $2.42 per MMBtu by 2010. The forecast was selected as representative of a number of natural gas price forecasts that were made during that time.

CEUM requires delivered, not wellhead or acquisition, prices as an input. Delivered natural gas prices for each Census region were derived from the weighted average transportation mark-ups reported by the Energy Information Administration (EIA) in Natural Gas Monthly for each Census region. The Natural Gas Monthly provides a consistent historical series of wellhead and delivered prices for calculating historical transportation margins. These margins were assumed to remain constant throughout the forecast period.

In the Constant-Price-Differential Base Case, delivered gas prices were assumed to equal current delivered spot prices in each region. To maintain a constant gas price relative to coal, these prices were assumed to decline from current levels ***12443** at the same rate as coal prices decline in CEUM.[FN834]

Rehearing Requests

The Joint Commenters assert that the fuel-price assumptions used in the model unduly favor the use of natural gas as a fuel and appear to understate adverse effects.

In particular, the Joint Commenters claim that the two alternative fuel-price cases use the same coal price assumptions. It states that the Competition-Favors-Coal Scenario is supposed to demonstrate the effects of economic assumptions that favor coal, but that this case actually uses price assumptions that reflect the lowest natural gas price of the projections cited in the FEIS. It states that the FEIS should have used projections less favorable to natural gas: for example, $2.51 per MMBtu in 2000 (Gas Research Institute) and $3.37 per MMBtu in 2010 (Energy Information Administration). Put differently, a more appropriate Competition-Favors-Coal Scenario would have used the projected highest reasonable natural gas prices relied on in the FEIS.

The Joint Commenters then claim that the Constant-Price-Differential Base Case is based on gas price assumptions that are far below the projected prices cited in the FEIS.[FN835] According to the Joint Commenters, this case assumes natural gas prices of $1.67 per MMBtu in 2000 and $1.57 per MMBtu in 2010. It asserts that these estimates are approximately 10 and 54 percent lower in years 2005 and 2010, respectively, than the lowest forecasts cited. A more appropriate Competition-Favors-Gas Scenario would have used the WEFA forecasts that contain the lowest reasonable projected gas prices.

Commission Conclusion

The claim that the assumptions unduly favor natural gas prices is incorrect. First, the assumption that lower gas prices will reflect favorably the environmental effects of the Rule is not valid. The impact of the Rule when gas prices are constant relative to coal is very close to the impact when gas prices are high relative to coal.[FN836] For example, the impact on total NO_X emissions in 2005 is higher when gas prices are constant relative to coal than when gas prices are high relative to coal (88,000 tons for the Constant-Price-Differential Base Case versus 55,000 tons for the High-Price-Differential Base Case).[FN837]

Second, the two price series were selected to give a range of variation in emissions that reflect differences in the price of gas relative to coal, rather than to project a "correct" natural gas price. As discussed in the FEIS, the Constant-Price-Differential Base Case reflects a continuation of the historical relationship between gas and coal prices over the past 10 years. Appendix G shows how forecasts over this period have consistently overestimated the price of gas relative to coal. It is therefore reasonable to consider the Constant-Price-Differential Base Case as one side of a reasonable range.

The prices selected for the other side of the reasonable range of gas prices relative to coal (the High-Price-Differential Base Case) were based on current forecasts at the time of the analysis. There were two primary reasons for selecting a lower gas price from the range of existing forecasts. First, the CEUM coal price forecast is determined within the model and could not be changed as an input. This coal price forecast was lower than the coal prices assumed in other forecasts. By picking a gas price forecast at the lower end of the range of current forecasts, and combining this forecast with the lower coal prices forecasts in CEUM, the analysis assumed a typical price of natural gas relative to coal.

Second, at the time the analysis was conducted, all major forecasting organizations stated that they expected their gas price forecasts to be lower. However, these organizations did not complete their forecasts for several months. Since the available forecasts were up to a year old, there was reason to believe the forecasts overstated the current thinking among forecasters regarding future natural gas prices. This reason was confirmed by the forecasts that appeared around the time the analysis was completed. For example, the forecast for the wellhead price of natural gas in the year 2010 from the EIA published in January 1996 was $2.10 per million Btu, 15 percent below the forecast of $2.42 assumed for the High-Price-Differential Base Case in the FEIS.

8. Expanded Transmission Analysis

Several commenters on the DEIS expressed concern that increases in transmission capacity resulting from open access might increase generation levels and thus air pollution. In response, the FEIS examined scenarios that increased transmission capacity substantially beyond current levels—including increases that the Commission believed would far exceed any transmission capacity increases that might occur as a result of the Rule. This analysis found that postulated increases in transmission do not affect emissions attributable to the Rule. The Commission also found that issues regarding enhancement of existing lines are more complex, and that this is due in part to the fact that state-level siting issues, the principal barrier to major increases in the transmission grid, are unaffected by the Rule. While competition will lead to improved efficiencies in generation, transmission will remain a regulated monopoly function. The Rule will reduce barriers to access, but will not open the transmission system to direct competition. Thus, the Commission concluded that the competitive effects of the Rule on transmission will be relatively small.[FN838]

Rehearing Requests

The Joint Commenters claim that the expanded transmission analysis is unduly conservative. It states that the Commission increased peak transmission usage from 75 percent of first contingency total transfer capability (FCTTC) to 105 percent of FCTTC, and that this expanded transmission analysis represent minimal actual expansions, the most extreme of which barely increases FCTTC above current levels by the year 2010. The Joint Commenters claim that the Commission should have examined additional expansion potential in those analyses that more accurately demonstrate the effects of transmission expansion.

Commission Conclusion

The Joint Commenters' claim that the expanded transmission analysis is inadequate is based on the premise that the FEIS used the wrong assumptions in developing transmission capacity. Joint Commenters contend that 100 percent of the FCTTC should have been used in CEUM. We believe that the use of 75 percent of this capacity to reflect annual capability is the appropriate level for modeling purposes. This reduction factor is necessary because the capability must be simultaneous systemwide capability and it must be sustainable. The FCTTC is a non-simultaneous "snapshot" transmission capability. The total simultaneous transfer capability is not accurately represented by adding together the ***12444** maximum transfer capability of each line in the system. The transmission system is a system. Loading on one line affects loading capability on all other lines in the system. This is especially true if the calculation is for capability over an extended period of time, as is the case with the FEIS, which uses transfer capability over one year. "Derating" as it has been called, is a reasonable way to represent the fact that a transmission system is capable of carrying less than the sum of the capabilities of the individual lines. Further, when modeling, if the model is calibrated so that the system is carrying actual historical flows—no matter what factor is used—the system will be carrying at or near its maximum capacity at constrained points which are the only points on the system where increased capacity would produce increased flows. As a result, increasing the transfer capability factor by up to 40 percent, as is done in the sensitivity analyses in Chapter 6 of the FEIS, represents a large change in the capability and use of the transmission system. Moreover, we note that this methodology has been used in previous CEUM analysis, where it was subject to review by electric utility experts. [FN839] For these reasons, the Joint Commenters' criticisms are invalid.[FN840]

The Joint Commenters challenge the assumptions used in the Commission's expanded transmission analysis as "unduly conservative" and "represent[ing] minimal actual expansions." Joint Commenters fail to explain in what respect they deem the expanded transmission analysis to be inadequate. They fail even to respond to the matters discussed by the Commission with regard to this issue in Order No. 888.

As we noted above in the discussion of the PA Com's argument that the Commission failed adequately to consider the alternative of instituting open access pursuant to section 211 of the FPA, it is insufficient for a party to complain that an analysis is inadequate without providing specifics.

C. Mitigation

The FEIS and Order No. 888 extensively assess the need for mitigation and discuss potential mitigation measures, including proposals advanced by commenters.[FN841] This discussion is perhaps best summarized by the conclusion to Chapter 7 of the FEIS, which states that:

This FEIS shows that the proposed rule is expected to slightly increase or slightly decrease total future NO_X emissions, depending on whether competitive conditions in the electric industry favor natural gas or coal. The insistence of commenters that the Commission adopt and implement mitigation measures is based on significantly overstated assumptions regarding the contribution of the proposed rule to the existing environmental problems. The analysis presented in Chapter 6 establishes that overstated assumptions about the impact of the proposed rule are simply wrong.

Nonetheless, in light of the importance of this issue, we have examined potential mitigation measures in detail, including those proposed by commenters, to ensure that environmental consequences of the rule have been fully and fairly evaluated. We do not believe mitigation should 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 in both the Northeast and the Midwest have invested substantial efforts towards 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 those 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 a 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.[FN[842]]

The FEIS goes on to note that the long-term existence of a significant ozone nonattainment problem in parts of the country has led to the development of mechanisms to address this issue. It states that any incremental increases in NO_X emissions that may result from the Rule can be addressed within this existing framework. In particular:

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 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, the problem is larger than the OTR can address. As a consequence, the Ozone Transport Assessment Group has been formed which encompasses the OTR and upwind states that contribute to nonattainment. OTAG is performing extensive photochemical grid modeling of the eastern U.S. to determine ozone transport patterns and to evaluate the efficiency of various control strategies. OTAG is considering imposing a cap and trade system for NO_X emissions in a 37-state area comprised of the Northeast OTR and upwind states. If the cap and trading system becomes ***12445** effective it 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.

We believe that the cap and trading system under consideration in the OTAG process is the preferred approach to the overall NO_X emissions problem. The OTAG process brings to the table the parties that must participate in making the difficult decisions to fully resolve this problem. The OTAG process possesses the technical resources and expertise to address the difficult scientific and technical issues that must be resolved to remedy this problem. More limited approaches cannot render a satisfactory solution. 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.[FN[843]]

Rehearing Requests

Pennsylvania PUC. The PA Com claims that the Commission has inappropriately declined to assume any responsibility for mitigating environmental impacts associated with the Rule. It states that the Commission has authority to take mitigation measures related to its regulatory actions and that the Commission can reasonably add environmental impacts to the list of factors to be weighed under the FPA's public interest standard. In this regard, it contends that the FPA grants FERC authority to place conditions on the regulation of rates and conditions of wholesale power sales and the interstate transmission of electric power as well as to order wholesale wheeling under certain circumstances.

The PA Com states that the Commission should act to minimize the likelihood of significant additional NO_X emissions by developing a mitigation plan to be implemented in conjunction with the Rule, and that FERC should use the results of the OTAG process to provide information to develop this strategy. The PA Com concludes that FERC should not require open access generically.

Vermont Department of Public Service. The Vermont Department of Public Service (VT DPS) contends that the Commission erred in failing to establish a monitoring program and a periodic reopener provision to address environmental considerations.

VT DPS submits that the Commission has given inadequate consideration to the possibility that the Rule may unnecessarily exacerbate environmental impacts. It notes EPA's claim in its referral letter to the Council on Environmental Quality (CEQ) that any future NO_X increases resulting from open access would exacerbate the difficulty of accomplishing reductions in NO_X emissions.

VT DPS claims that the environmental review process has not facilitated the ability of affected parties to review all modeling assumptions. It also claims that other environmental reviews suggests more serious NO_X emission consequences of the Rule than acknowledged by the Commission.

VT DPS states that given the possibility that the FEIS conclusions may prove wrong, the Commission should take steps to permit timely reevaluation of its program. VT DPS recommends that the Commission establish an ongoing monitoring program to determine if the Rule poses an unacceptable risk to air quality. It states that a monitoring program would allow the Commission to take timely action to mitigate any unintended consequences of the Rule. The Commission should also provide for periodic reevaluation of the Rule's open access provisions and should commit to a comprehensive reevaluation of the Rule's environmental impacts every five years over the next 20 years.

New York Attorney General. The New York Attorney General (Attorney General) states that the federal government should ensure that New York and other Northeast states do not bear the burden of any increased air pollution resulting from deregulation.[FN844]

The Attorney General asserts that utilities in upwind states have a competitive advantage relative to Northeast utilities because they are subject to less extensive environmental controls. The Attorney General contends that deregulation may result in these plants increasing generation, thus increasing emissions that will contribute to the inability of New York and the Northeast to meet the federal ozone standard. The Attorney General claims that, regardless of the effects of the Rule, studies show that a 50 percent reduction in NO_X emissions from all sources east of the Mississippi will be necessary for New York and other Northeast states to achieve the ozone standard.

The Attorney General states that Congress has placed limits on EPA's authority to protect New York from upwind emissions, and that it is therefore essential that FERC exercise any authority it may have to mitigate the environmental effects of the Rule.

The Attorney General claims that EPA's proposal in its February 20, 1996 comments to place a cap on NO_X emissions would mitigate the effects of the Rule; it suggests basing this system on the MOU pursuant to authority residing in EPA and/or FERC. Under this proposal, a utility would be permitted to take advantage of deregulation if it simultaneously takes steps to prevent emission increases.

Joint Commenters—Overview. The Joint Commenters state that FERC has failed to consider and disclose the potential environmental effects of the Rule, and that FERC's decision that it lacks authority to implement mitigation is contrary to law.

The Joint Commenters' premise is that, despite deficiencies in the Commission's analysis which understate the effects of the Rule, the FEIS nonetheless presents data confirming that open access will have significant adverse environmental impacts. Joint Commenters posit that increased emissions from open access could seriously threaten achievement of Clean Air Act requirements and other environmental commitments. It reasons that the Commission therefore must develop and implement environmental mitigation.

The Joint Commenters begin with the assertion that the data presented in the FEIS do not support the conclusion that the effect of the Rule on air pollution will be insignificant. It claims that the Commission relied on cases that show small impacts. Joint Commenters note in this regard that EPA has determined that any increase in NO_X emissions from restructuring is unacceptable and should be remedied.

Joint Commenters then assert that FPA sections 205 and 206 require the Commission to adopt mitigation. It claims that case law supports the proposition that both NEPA and the FPA authorize FERC to mitigate the adverse environmental impacts arising from its action. Even assuming arguendo that it was reasonable for the Commission to reject specific proposed mitigation measures, it is unreasonable the deny the existence of authority to mitigate. The Commission should remedy this by adopting mitigation concurrent with implementation of Order No. 888.

According to Joint Commenters, the FEIS establishes that competitive electric markets will likely result in higher utilization of heavily polluting coal-fired generation. Thus, in view of EPA's statement in its referral to CEQ that any increase in NO_X emissions could seriously undermine attainment of health based standards, the FEIS ***12446** finding that emission increases that may be as large as 315,000 tons per year are insignificant is not supported by the record.

Joint Commenters then argue that not only does the decision not to implement mitigation measures risk nonattainment of public health goals, it will fail to achieve the regulatory objective of fair and efficient bulk power competition. It contends that without concurrent environmental mitigation, the Commission will put in place a market structure that is inherently discriminatory and that arbitrarily shifts costs. It states that Order No. 888, in effect, provides a class of competitors with an undue preference subsidy. This undue preference results from the fact that the owners of coal-fired generation that are not subject to emissions regulation will be able to shift financial responsibility for their pollution to competitors in downwind regions. This discriminatory situation will distort the bulk power market and produce inefficiencies that the Commission has not addressed.[FN845]

Open Access Will Have Significant Adverse Impacts. The Joint Commenters state that some FEIS scenarios show that restructuring is likely to have significant adverse environmental effects. It claims that the sensitivity analyses confirm that low-cost, high-emission coal plants may increase their capacity utilization from an average of 62 percent in 1993 to 81.5 percent by 2010 and that this increase is associated with an additional 515 billion kWh of coal generation per year by 2010 above 1993 levels, assuming expanding transmission. FEIS data further indicate that 110 billion kWh of this annual increase by the year 2010 will be attributable to competition under the open access policy compared to the frozen efficiency case.

The Joint Commenters assert that the FEIS also confirms that this increase in coal-based generation will increase NO_X emissions across the 37-state OTAG region by 250,000 tons per year by 2010 (315,000 tons for the entire U.S.) and result in a cumulative NO_X emissions increase across the U.S. of 530,000 tons by 2000 and 2.7 million tons by 2010.

The Joint Commenters assert that the impacts of a 250,000 ton NO_X increase across the OTAG region are extremely significant, particularly in downwind nonattainment areas, and fly in the face of EPA's determination that any increase is unacceptable.

The Joint Commenters contend that the Commission understates the significance of these numbers by emphasizing percentages and using national figures. According to Joint Commenters, the FEIS demonstrates that regional increases in NO_X include a seven percent increase in the East North Central region, 10 percent in the Mountain region and 26 percent in the Pacific regions. These references are to emissions in 2005. The percentages in the year 2010 are approximately five percent nationally, rather than the three percent discussed in Order No. 888.

The Joint Commenters state that the FEIS also shows that increased utilization of coal plants could significantly add to utility carbon dioxide (CO_2) emissions, which would conflict with the Clinton Administration's commitment to stabilize greenhouse gas emissions at 1990 levels by the year 2000. It states that the Competition-Favors-Coal Scenario projects that annual utility CO_2 emissions will increase by 285 million tons by 2000 and by 737 million tons by 2010; and that the FEIS attributes about 10 percent of the increase to the Rule. It argues that this increase will threaten international commitments of the U.S. Government. The Joint Commenters assert that utility CO_2 emissions are not currently on track to fulfill national and international climate protection objectives and open access competition, to the extent it favors existing coal plants, will exacerbate these trends.

The Joint Commenters then claim that in addition to the emissions impacts that are identified in the FEIS, EPA's technical analysis indicates that the Rule has the potential to cause much larger impacts than the FEIS estimates for the Competition-Favors-Coal Scenario. EPA's evaluation, which Joint Commenters claim does not incorporate worst case scenario assumptions, indicates that the potential increases in NO_X emissions from open access could be more than twice the increases projected in the FEIS Competition-Favors-Coal Scenario in years 2000, 2005 and 2010. The potential that FERC's highest polluting case understates emissions increases to this extent illustrates the uncertainty surrounding the impacts of open access, particularly the uncertainties surrounding the accuracy of the Commission's estimates, and the critical importance of developing mitigation programs.

Authority to Mitigate. The Joint Commenters assert that the Commission's rejection of authority to mitigate environmental impacts is contrary to law and arbitrary and capricious. It states that the Commission's rejection is inconsistent with Commission claims about its sections 205 and 206 authority, and that both NEPA and the FPA permit FERC to mitigate adverse environmental impacts. Thus, while it may be reasonable for the Commission to reject specific mitigation measures, the Commission's decision that it lacks authority to implement mitigation constitutes an arbitrary and capricious exercise of agency authority.

The Joint Commenters argue that NEPA authorizes agencies to consider and address environmental impacts so long as any actions undertaken do not conflict with the agency's authorizing statute. It states that a number of cases support the proposition that FERC's FPA authority is broadened by NEPA—that NEPA policies and goals inform and expand the FPA's definition of public interest. In effect, NEPA establishes a legal nexus between the Commission's primary regulatory duties and environmental protection. Thus, courts have upheld agency mitigation actions under NEPA even when the agencies have no explicit environmental protection mandate. The Joint Commenters assert that the Commission did not address these cases in concluding that it lacks authority to mitigate adverse environmental impacts under sections 205 and 206 and the FPA's general public interest standard.

The Joint Commenters assert that if NEPA is to be given practical effect, agencies must have authority to do more than study the potential environmental impacts of proposed actions. To interpret and administer federal laws in accordance with NEPA policies, agencies must have the authority to use their statutory powers in ways that implement NEPA policies. The arena of permissible environmental action is constrained only by the limits of the agency's jurisdictional authority under its enabling statutes. Thus, the only limits on FERC's ability to implement environmental mitigation are those defined by the FPA. Therefore, the question is whether mitigation falls within the regulatory powers of FERC.

The Joint Commenters argue that the FPA authorizes the Commission to mitigate the environmental effects of its actions, stating that the public interest standard of FPA section 201 encompasses the environmental and other competitive concerns discussed in its request for rehearing. The Joint Commenters state that NAACP v. FPC, 425 U.S. 662 (1976) and similar cases establish that FERC has jurisdiction to address environmental concerns since such concerns are directly related to FERC's regulation of economic interests in the electric industry.

The Joint Commenters assert that FERC's duty to ensure just and ***12447** reasonable rates that are not unduly discriminatory or preferential also encompasses non-economic factors in appropriate circumstances. It argues that the Commission's reliance on Office of Consumers' Counsel v. FERC, 655 F.2d 1132 (D.C. Cir. 1980), to support its narrow reading of the FPA's public interest standard is misplaced.

The Joint Commenters then take issue with the position that the Commission lacks authority to implement mitigation because it has insufficient expertise in air pollution control and because Congress gave EPA authority to address such issues. It states that the record does not support a conclusion that FERC lacks the expertise necessary to provide for mitigation of the Rule's impacts. Moreover, nothing would prevent the Commission from acting in concert with EPA to take advantage of EPA's expertise.

The Joint Commenters state that, unlike the situation in Office of Consumers' Counsel, Congress has given FERC, along with EPA and other federal agencies, the responsibility to address the environmental effects of its actions. In this case, Joint Commenters are asking the Commission to mitigate the environmental impacts of its Rule, not to assert jurisdiction proactively over air pollution matters or to usurp EPA's role. Under Order No. 888's logic, no federal agency would have authority to mitigate the environmental impacts of its proposed actions because EPA is the primary agency with environmental expertise and responsibility.

The Joint Commenters then argue that the Commission's jurisdiction to consider environmental issues also derives from a traditional analysis of FERC's jurisdiction over wholesale power rates. It states that if the Commission does not allocate environmental responsibility to high-emission utilities, environmental compliance costs will be transferred to downwind utilities and their customers. These utilities will be required to incur costs to reduce emissions and must increase rates to recapture these costs. Thus, Order No. 888 will directly affect the costs that are included in electric rates, which the Commission has authority to review under sections 205 and 206.

The Joint Commenters conclude their discussion by noting that, while it may have been reasonable for the Commission to reject specific mitigation proposals, the Commission should reexamine the position that it has no authority in this area and instead acknowledge that the exercise of that authority is not warranted here given the conclusions in the FEIS. The Joint Commenters go on to note that EPA proposed in its referral to CEQ a mitigation approach that seeks the Commission's commitment to future actions and outlines immediate actions EPA will take to address the potential NO_X emission increases identified in the FEIS. The Joint Commenters state that although it believes EPA's proposal is reasonable and strongly support the tracking system recommended, the Commission should develop a backup NO_X mitigation mechanism by the end of 1996 to assure that Order No. 888 will be implemented without adverse environmental impacts.

Commission Conclusion

Need for Mitigation. The FEIS examines fully claims that the Rule will have significant environmental impacts requiring mitigation. As stated in Order No. 888:

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 be largely determined by the relative prices of natural gas and coal, the two main fuels used to generate electric power in most regions.

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. 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 emissions through the year 2000. Thereafter, NOx 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. [[FN846]]

The Commission went on to note that it believes the appropriate no-action alternative was used to conduct this analysis. "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."[FN847] The Commission then explained:

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). 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. 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. ***12448**

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. [[FN848]]

Thus, there is no basis for claims that the Rule will result in large increases in pollution from generating plants operating under less stringent environmental controls. This negates arguments calling for the imposition of mitigation measures to ensure that all entities compete under an identical regulatory regime.

We note in this regard that the Joint Commenters' claim that the Rule may result in emissions increases as large as 315,000 tons per year by the year 2010, and cumulative NO_X increases across the United States of 530,000 tons by 2000 and 2.7 million tons by 2010, is incorrect. The Joint Commenters derive this result by selectively choosing numbers from the FEIS, comparing sensitivity cases designed to be unrealistically low and high extremes. The low emissions case selected is the frozen efficiency case that represents a complete reversal of current industry and regulatory trends that are occurring without the Rule. The high emissions case represents an increase in transmission capacity that cannot reasonably be ascribed to the Rule. The FEIS indicates that these cases were used to examine the sensitivity of findings to certain extreme assumptions maintained by commenters and are not the appropriate cases to use for considering potential environmental impacts from the Rule.

Moreover, the Joint Commenters reference increases from the Rule without noting equally likely decreases. Even with the lower emissions resulting from the unrealistic frozen efficiency case, the FEIS finds decreases in emissions from the Rule when competitive forces lead to greater efficiency for natural gas generation compared to coal.

Actions to Mitigate NO_X Emissions. Moreover, EPA and the Commission have committed to undertake the actions sought by those seeking rehearing on this issue. EPA in its referral to the CEQ concurred with the Commission "that the open access rule is unlikely to have any significant adverse environmental impact in the immediate future, and that in light of its anticipated economic benefits, implementation of the Rule should go forward without delay." EPA also "concludes that the FERC has conducted an adequate analysis under the National Environmental Policy Act of the environmental impacts of the open access rule under a range of possible scenarios." In particular, EPA concurs that the "FERC made a reasonable choice of models (CEUM) and made assumptions for various factors input into the model that lie within the range of reasonable assumptions."

EPA also concurred with the Commission that NO_X emissions increases associated with the Rule, if any, should be addressed as part of a comprehensive NO_X emissions control program developed by EPA and the states under mechanisms available under the Clean Air Act. This includes support for the efforts of OTAG to develop standards for measuring the scope of the ozone transport problem and developing emissions reduction strategies.

More significantly, EPA committed to use its authority under the Clean Air Act to support successful completion of the OTAG process. EPA will establish a NO_X cap-and-trade program for the OTAG region through Federal Implementation Plans "if some States are unable or unwilling to act in a timely manner."[FN849]

EPA also states that if "the OTAG and Clean Air Act processes fail to produce the necessary pollution limitations in a timely manner, EPA will call upon all other interested Federal agencies to assist in solving the problem." In this context EPA would ask the Commission to contribute by further examining, through a Notice of Inquiry, possible strategies for mitigating NO_X emissions increases associated with the Rule. EPA also suggested that if it determines that the problem must be addressed through EPA initiation of Federal Implementation Plans, FERC could then initiate a rulemaking to propose "suitable means under the Federal Power Act" for mitigating impacts attributable to the Rule.

The Commission, on May 29, 1996, issued an order responding to EPA's referral. The Commission stated that:

Given EPA's commitment to address air pollution issues, it is appropriate for EPA to seek assurances that if its best efforts are not successful, other agencies will examine their abilities to address the problem within the scope of their respective statutory authorities. Given the broad powers vested in EPA by the Clean Air Act, we fully expect EPA to succeed. We also note that if EPA is unable ultimately to address the issue, either through the voluntary OTAG process or by means of its authority under the Clean Air Act, we doubt that other agencies will be able to resolve the NO_X emissions problem under more limited authority. In such circumstances, action by the Congress may be necessary.

Nevertheless, we believe that the Commission should be willing, if called upon under the circumstances EPA describes, to consider whether, under the Federal Power Act, it can and should attempt to address NO_X emissions issues attributable to the

Rule. Therefore, if EPA concludes that the OTAG process has not succeeded in meeting its objectives in a timely manner, we will initiate a Notice of Inquiry to further examine what mitigation might be permissible and appropriate under the Federal Power Act. Such an inquiry would solicit public comment on how to assess appropriately the air pollution impacts attributable to the Final Rule, suitable ways in which to address such impacts, if any, and the scope of the Commission's authority to address such impacts. ***12449**

Additionally, under the extraordinary circumstances in which EPA would undertake a Federal Implementation Plan, the Commission would agree to initiate contemporaneously a rulemaking to propose possible mitigation that could be undertaken by the Commission under the Federal Power Act. Such a rulemaking would be undertaken on the basis of the NOI mentioned above and would be appropriate only if environmental harm attributable to the rule that warranted mitigation is demonstrated. The Commission would rely upon information gleaned in the NOI in proposing possible mitigation strategies that are workable, tailored to address consequences attributable to the Rule, and consistent with our statutory authority. In no event would the Commission propose a mitigation strategy that would undermine the purposes of the rule to provide open transmission access on a non-discriminatory basis. We emphasize that neither the NOI nor the rulemaking, if they occur, will affect the implementation of the rule as required under Orders of the Commission. [[FN850]]

Thus, EPA has concluded that the Commission conducted an adequate analysis of the impacts of the Rule and agrees that the Rule is unlikely to have any significant adverse environmental impact in the near future. EPA also concurs that NO_X emissions increases associated with the Rule, if any, should be addressed as part of a comprehensive NO_X emissions control program developed by EPA and the states under mechanisms available under the Clean Air Act. This includes support for the efforts of OTAG to develop emissions reductions strategies. EPA will use its Clean Air Act authority to support completion of the OTAG process. EPA is prepared to establish a NO_X cap-and-trade program for the OTAG region through Federal Implementation Plans if states are unable or unwilling to act in a timely manner.

This commitment by EPA puts to rest the concerns expressed by those seeking rehearing on the issues of mitigation and disparate emissions standards. As stated in the FEIS:

The Ozone Transport Assessment Group (OTAG) represents [a] broad[] effort to deal with the interstate transport of pollutants that form ozone. OTAG is a voluntary organization that consists of 37 eastern states, the District of Columbia, and the EPA; industry and environmental groups also participate in the OTAG process. It was organized by the Environmental Council of States to study the transport of ozone and its precursors in the eastern U.S. and to develop mitigation strategies. OTAG is performing extensive photochemical grid modeling to determine ozone transport patterns and to evaluate the efficiency of various control strategies. OTAG intends to submit its findings regarding transport patterns and its recommendations for mitigation of ozone transport to EPA by January 1997.

OTAG is considering a number of strategies to mitigate the problem of ozone nonattainment. One strategy is the imposition of a cap and trading system for NO_X emissions in a 37-state area compromising the Northeast OTR and upwind states. If the cap and trading system becomes effective, it will fully mitigate any NO_X emissions increases attributable to open access transmission within the 37-state area, because increases within this area would have to be offset by a corresponding emission reduction.

The OTAG cap and trade program may not deal directly with emissions of pollutants other than NO_X. However, a cap on NO_X is likely to mitigate CO_2 and mercury increases, because internalizing costs of NO_X controls on coal-fired units is likely to dampen increases in capacity utilization of such units.[FN[851]]

The OTAG process includes the players of concern here—both the states from which alleged pollution increases would originate and the states that would be affected by the increased pollution. OTAG has a process underway to determine transport patterns and to evaluate control strategies. One strategy that is being considered is the imposition of a cap and trade system for NO_X emissions like that sought on rehearing here.[FN852] OTAG originally intended to submit its findings regarding transport patterns and recommendations for mitigation to EPA by January 1997. As a result of its decision to conduct additional modeling to determine the appropriate geographic applicability of emission reduction strategies, OTAG has extended its January timeframe by a few months, and now intends to complete its process by April or May 1997.

While OTAG is continuing its efforts, EPA is moving rapidly forward to remedy in a comprehensive fashion the interstate transport of air pollution. On January 10, 1997, EPA issued a notice of intent to use the authority granted it by sections 110(k)(5) and 110(a)(2)(D) of the Clean Air Act to require states to submit state implementation plan (SIP) measures to ensure that emission reductions are achieved as needed to prevent significant transport of ozone pollution across state boundaries in the Eastern United States. This notice "announces EPA's intention to conduct the formal process for implementing the regional reductions in ozone precursors that are necessary for areas in the Eastern United States to reach attainment." [FN853] EPA states that it intends to publish a Notice of Proposed Rulemaking in March 1997 that "will propose overall amounts or ranges of NO_X and/or VOC emission reductions that each State would need to achieve to reduce the boundary condition concentrations of ozone and its precursors within a specified timeframe and require the submission of SIP controls to achieve these reductions."[FN854] The notice of inquiry also states that the SIP revision must contain a schedule for adoption and implementation of these measures. It notes that while EPA could allow up to 18 months for SIP submittals under section 110(k)(5), "EPA is considering a more accelerated schedule for submittals under this SIP call to attain air quality benefits sooner and to facilitate area specific SIP planning."[FN855] EPA notes that as it goes through the process of developing an implementation program for the new standard, it will be able to take advantage of the information gathered by OTAG and account for emission reductions that result from the recommended strategy. EPA intends to publish the final SIP call notice in summer 1997.

Thus, actions to address the concerns with regard to mitigation and emissions standards disparity are taking place at this time and should be in place in the near future. This lays to rest as well concerns that any near-term impacts of the Rule have not been taken into account.

The Commission's Authority to Mitigate. The PA Com makes an unsupported assertion that the FPA's public interest standard authorizes the Commission to take mitigation measures related to its regulatory actions, and that the Commission should use the results of the OTAG process to develop a mitigation strategy.

The Joint Commenters argue that the Commission has broad authority under NEPA to mitigate the environmental consequences of its proposed actions. It contends that NEPA broadens the Commission's FPA authority—that NEPA policies and goals inform and expand the FPA's definition of the public interest. It also argues that the Commission's duty to ensure just and reasonable rates that are not unduly discriminatory or preferential also ***12450** encompasses non-economic factors in appropriate circumstances.

The Joint Commenters conclude that, while it may be reasonable for the Commission to reject specific proposed mitigation measures, the Commission should, at a minimum, acknowledge that the FEIS demonstrates that the exercise of that authority is not warranted in this case. The Joint Commenters add that the Commission should initiate a rulemaking proceeding that considers mitigation options and evaluates the effectiveness of alternative strategies and proposals. The Joint Commenters concur that EPA's commitment to address air pollution issues is reasonable, but would have the Commission develop a backup NO_X mitigation mechanism by the end of 1996.

Thus, the PA Com and the Joint Commenters would have the Commission revisit in this order, by means of a generalized reexamination of the Commission's authority to impose mitigation, the conclusion in Order No. 888 that the mitigation measures recommended by commenters are beyond our authority to implement.

Order No. 888 and the FEIS fully examine the need for mitigation and the Commission's legal authority to impose mitigation measures. That examination led to the conclusion that: (1) the insistence of certain 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, and that these assumptions about the impact of the Rule are wrong; (2) the existence for many years of a significant ozone nonattainment problem in part of the U.S. has led to the development of mechanisms to address this issue; (3) the mitigation recommendations suggested by commenters suffer from serious legal and practical shortcomings; and (4) the mitigation measures recommended by commenters are beyond the Commission's authority to implement and strong policy considerations militate against their adoption.

The PA Com and Joint Commenters have not raised any arguments that warrant revisiting the Commission's exhaustive examination of this issue in Order No. 888 and the FEIS, and we hereby reaffirm those decisions. We note in this regard that the PA Com did not advance a specific mitigation proposal in comments on the EIS and does not challenge the Commission's rejection in Order No. 888 of specific mitigation proposals advanced by other commenters. The Joint Commenters did propose a specific mitigation strategy which the Commission rejected because, among other things, it would have the Commission impose a revenue collection measure. The Joint Commenters do not challenge the Commission's analysis of its proposal or seek rehearing of its rejection. Instead, the Joint Commenters seek an acknowledgement from the Commission that, given the conclusions in the FEIS, the exercise of authority to mitigate is not warranted in this case. As we stated in Order No. 888 and the FEIS, mitigation is not warranted given the conclusions reached in the FEIS. The Commission also notes that we have thoroughly examined our legal authority in Order No. 888 and we find nothing in the arguments on rehearing that persuade us now to a different result. We have agreed to further examine our authority to engage in environmental mitigation through a Notice of Inquiry if EPA determines that the OTAG efforts are not successful. Therefore, it is unnecessary in this context to opine further in the abstract as to the scope of the Commission's mitigation authority.

Because the PA Com and the Joint Commenters have raised no new arguments that were not thoroughly addressed in Order No. 888 and the FEIS, it is unnecessary to repeat here the thorough analysis of this issue set forth in those documents. The Commission declines to grant rehearing on this issue.

Other Mitigation-Related Issues. VT DPS states that the Commission has given inadequate consideration to the possibility that the Rule may unnecessarily exacerbate environmental impacts and that the Commission, therefore, should adopt mitigation.

This statement, which VT DPS fails to substantiate, is incorrect. The FEIS and the process which led to the conclusions contained therein fully consider the environmental impact of the Rule. VT DPS fails to identify any particulars in which the FEIS is deficient. VT DPS's disagreement appears to be a generalized dissatisfaction with the substantive conclusion reached by the FEIS that the Rule will not have significant environmental impacts.

VT DPS next claims that the Commission's environmental review process has not facilitated the ability of affected parties to review all of the modeling assumptions. It also claims that other environmental reviews suggest that the Rule will have more serious NO_X emissions consequences than acknowledged by the Commission.

VT DPS again attacks the FEIS with a broad brush, but fails to identify ways in which the ability of parties to review modeling assumptions has been impeded. Likewise, it does not identify areas in which modeling assumptions have not been identified or any way in which its understanding of the FEIS has been hampered by the alleged unavailability of certain modeling assumptions. VT DPS is very late in raising such claims. The time to raise such issues is during the scoping process or in comments on the DEIS.

It is unclear what other environmental reviews VT DPS is referring to or the ways in which those reviews allegedly suggest that the Rule will have more serious NO_X emissions consequences than acknowledged by the Commission. Even if the unidentified studies reach different results than the FEIS this does not invalidate the conclusions contained in the FEIS. The mere fact of disagreement, even disagreement among experts in a given area, does not invalidate a study. [FN856]

VT DPS next recommends that the Commission establish an ongoing monitoring program in consultation with environmental agencies. It states that a monitoring program would allow the Commission to take timely action to mitigate any unintended consequences of the Rule.

An EIS is required to be prepared, when appropriate, prior to agency action. As the Supreme Court has stated, the moment at which an agency must have a final statement ready is the time at which it makes a recommendation or report on a proposal for federal action. [FN857] There is no requirement that an agency continue to evaluate the environmental impacts of a project after it is implemented, particularly where, as here, the agency has determined that the proposal is not likely to have adverse environmental impacts.

Moreover, as discussed extensively above, EPA's commitment to take action with regard to the underlying problems of the interstate transport of air pollutants provides a fuller measure of relief than that sought by VT DPS.

The New York Attorney General claims that it is essential that FERC exercise any authority it may have to mitigate the environmental effects of the Rule because Congress has limited EPA's authority in this regard. The Attorney General also claims that EPA's proposal in its comments of February 20, 1996 on the DEIS to place a cap on NO_X emissions would mitigate the effects of the Rule; it suggests basing ***12451** this system on the MOU. The Attorney General urges implementation of this system on the federal level pursuant to authority residing in EPA and/or FERC.

We note first that Congress has made a full grant of authority to EPA to address the issue of the interstate transport of air pollution. As discussed extensively above, EPA has committed to address this issue, and to use its authority pursuant to the Clean Air Act if states are unwilling to address this issue cooperatively through the MOU process. Thus, EPA has committed to undertake the relief sought by the Attorney General. If EPA is unsuccessful, the Commission has pledged to assist in this effort as discussed above.

D. Emissions Standards Disparity

Order No. 888 addresses claims that the Commission should "level the playing field" as to environmental standards. The argument was that unless the Commission imposes mitigation, competitors with "dirty" generation will be favored over "clean" competitors. Those urging the adoption of measures to level the playing field argue that mitigation of environmental impacts has a direct relationship to ensuring that open access is implemented under terms of economic fairness for all utilities, and not merely those with current low-cost regulatory advantages.

We responded to those arguments in Order No. 888 by noting that:

[A]ll 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.

* * * * *

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.

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. Thus, the conditions we have imposed have involved economic regulatory matters within our purview under the FPA. 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.

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. 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. [[FN858]]

Rehearing Requests

Pennsylvania PUC. The PA Com asserts that the FEIS does not adequately address challenges posed by the Clean Air Act Amendments of 1990. The PA Com contends that the Rule may shift power production from Pennsylvania plants with strong environmental controls to upwind plants with less stringent controls, and that prevailing climatic patterns may transport the increased pollution downwind. It states that mitigation is needed to prevent degradation of downwind air quality and the imposition of further costs and limits on downwind generation.

The PA Com states that the Clean Air Act Amendments imposed stringent emission standards on Pennsylvania generation, but did not impose similar standards on neighboring states such as Ohio and West Virginia. It claims that the FEIS does not sufficiently consider these requirements. The PA Com concludes that implementing open access without mitigation will place Pennsylvania utilities at a competitive disadvantage, and that this result is inconsistent with the public policy goals of the Clean Air Act and the Federal Power Act. The PA Com also asserts that the Rule may discriminate against Pennsylvania utilities and the Pennsylvania coal industry, and that the combination of the Clean Air Act and Order No. 888 places Pennsylvania at a disadvantage in the competition for new industry and jobs.

The PA Com claims that Order No. 888 may push states in the Northeast Ozone Transport Commission into repudiating the existing MOU. It claims that it is inconsistent for one federal purpose which is statutorily clear (i.e., clean air mandates established by the Clean Air Act Amendments) to be prejudiced by another federal purpose with only inferential statutory authority (i.e., open access under sections 205 and 206 of the FPA).

The PA Com asserts in this regard that Phase II of the MOU will require by 1999 a 55 percent reduction in NO_X emissions in most of Pennsylvania and 65 percent (0.2 lbs/mmBTU) in the Philadelphia area. Title I of the Clean Air Act requires that the Northeast make reasonable progress towards attainment. If the inner zone of states comprising the Ozone Transport Commission do not achieve attainment, Phase III of the MOU will be implemented in 2003. Phase III requires a 75 percent reduction in emissions (0.15 lbs/mmBTU) for the entire state. According to the PA Com, to meet Phase III requirements most Pennsylvania coal-fired stations will have to install Selective Catalytic Reduction technology at a capital cost of $2.3 to $3.5 billion. It states that other Northeast states will be required to make expenditures that are much lower, and that states such as West Virginia and Ohio will not be subject to these requirements at all.

New Jersey BPU. The NJ BPU poses a similar concern. It states that upwind power plants are designed to meet NO_X emission standards which are substantially less restrictive than those required in New Jersey. The NJ BPU claims that this will have a two-fold impact—New Jersey air quality will be degraded through air transport and New Jersey utilities will be placed at a ***12452** significant cost disadvantage. The NJ BPU states that it is inconsistent to assert substantial incremental benefits associated with competition brought about by the Rule, while asserting that the Rule will not result in any change in the utilization of existing power plants.

NJ BPU asserts that there are disparities in the electric industry among suppliers with regard to environmental impacts and costs, and that the Commission did not take this into account in determining the total economic benefit of a competitive wholesale generation market. It notes that the Commission may consider that it produced an economic benefit if the Rule enables a buyer in the Southeast to displace self-generated 4-cent power with 3-cent power from the Midwest. The NJ BPU contends, however, that if emissions from the plants producing the electricity result in 1.5 cents worth of mitigation costs on a downwind state, an appropriate economic analysis would conclude that the transaction actually increases total costs. NJ BPU asserts that it was inappropriate for the Commission to focus on economic gains while leaving cost issues to be dealt with by other entities.

NJ BPU recommends that the Commission adopt an integrated environmental, economic and energy policy approach which embraces the underlying principles in EPA's acid rain program. It states that the Commission should call for specific, significant and enforceable reductions in NO_X emissions coupled with a market based trading program of emissions. It asserts that this approach would ensure a fair and competitive playing field at a fraction of the expected cost savings from the Rule.

Joint Commenters. The Joint Commenters assert that the Commission has a duty under the FPA to mitigate undue preferences that affect competition in the wholesale power market. It concludes that this mandate must be applied here where implementation of open access policies without concurrent environmental mitigation will cause generation-owning utilities to face a discriminatory competitive situation.

The Joint Commenters note that the Northeast is an ozone nonattainment area because of high levels of ambient ozone pollution, and is therefore subject to strict NO_X reduction requirements. It states that regional utilities have invested significant sums in pollution reduction facilities and cleaner generation to meet legal requirements to reduce emissions. It contends that these utilities will be subject to additional NO_X reduction requirements, thus increasing generation costs, if ambient ozone levels increase as a result of competition.

The Joint Commenters contend that if open access increases emissions, utilities in the Northeast that have increased their generation costs to reduce air pollution will be required to bear additional costs to offset the impacts of increased upwind emissions. It states that the cost to Northeast utilities to offset additional NO_X emissions will likely be substantially higher than the costs would be to upwind competitors to mitigate emissions at the source. It claims that offsetting the impacts of a 250,000 ton NO_X increase in downwind nonattainment areas, where marginal NO_X and volatile organic compound (VOC) control costs average about \$3,800 per ton, could total \$1 billion. On the other hand, mitigating the pollution increases at generation sources which currently operate with minimal environmental controls would cost about \$500 per ton, or \$130 million. The Joint Commenters assert that this cost differential will be hidden from the competitive market because Northeast generators will bear the cost.

The Joint Commenters assert that this demonstrates that the wholesale bulk power market in the eastern United States is suffused with an existing undue preference that inordinately favors one category of competitors by allowing them to produce and sell power at a lower marginal cost. This preference exists today as a result of costs incurred in the past to meet Clean Air Act obligations; the FEIS demonstrates that Order No. 888 could worsen this situation as a result of increased sales from older, higher-emitting upwind coal generators.

The Joint Commenters add that, aside from the competitive unfairness of this situation, the undue preferences will produce inefficiencies which distort investment decisions and increase the overall cost to produce electricity—the antithesis of what Order No. 888 is meant to achieve. It asserts that these inefficiencies will occur in four ways:

Sources in downwind nonattainment areas could have to spend hundreds of millions of dollars to address increased air pollution resulting from open access if polluting plants do not mitigate at the source. Thus, less efficient investments will be made to reduce air pollution and the overall cost of generating electricity will be higher than in a competitive market that is not distorted by discrimination.

Order No. 888 could adversely impact the economic dispatch of generating sources under competitive conditions. In the absence of mitigation, generation from higher polluting upwind plants could displace generation from plants in the Northeast that operate more efficiently at the margin. As utilities in the Northeast are required to add more costly emission controls in response to interregional migration of air pollution, their operating costs will be driven up and may exceed the costs of less efficient plants which have avoided such controls. Thus, in the absence of mitigation, Order No. 888 may foster less efficient utilization of generating resources.

Implementation of Order No. 888 without mitigation may distort the market for future generation capacity. If older, more highly-polluting plants can shift the environmental cost of production to other wholesale generators, they are likely to expand their output to address market needs, thus reducing the demand for more efficient, clean-burning generating facilities.

Transmission from the Midwest to the East is often heavily constrained. Consequently, a distorted price signal to increase generation in the Midwest would exacerbate existing constraints and improperly stimulate the construction of new transmission capacity to support additional interregional transactions.

The Joint Commenters conclude that the Commission has an obligation to exercise its authority in non-arbitrary manner, particularly when acting to prevent undue discrimination.

Finally, the Joint Commenters disagree with the Commission's response to this issue in Order No. 888. It asserts that the Commission and the courts have found in the "price squeeze" context that the Commission has authority to remedy anti-competitive discrimination, even when it is caused by regulatory practices of others over which it and its regulated public utilities have no control. Second, the Commission has the authority and responsibility to address environmental issues that directly affect and have a nexus to its section 205 and 206 responsibilities. Third, if the competitive market that the Commission wishes to create will not operate fairly or efficiently, the Commission has a duty to consider whether it should go forward at all if it believes it does not have the power to remedy important adverse competitive consequences.

Commission Conclusion

Congress has empowered the Commission to remedy undue discrimination and promote competition; it has not authorized the Commission to equalize the environmental costs of electricity production in order to ensure "economic fairness." Homogenization of competitors, or their costs, has never been a goal of the FPA.

Action in Order No. 888 to remedy undue discrimination in access to the monopoly owned transmission wires ***12453** that control whether and to whom electricity can be transported in interstate commerce does not require action by the Commission to cure all competitive differences between participants in the utility marketplace. This is particularly true where the disparities arise because Congress has established policies with regard to competing issues of national significance and charged other agencies of the federal government with implementing those policies. The assertion that the Commission must eliminate any competitive disadvantage arising from congressionally mandated policies, including the vital national policies set forth in the Clean Air Act, before it can act to remedy undue discrimination and encourage competition in the electric utility industry is in error.

Furthermore, as noted above, the analysis reflected in the FEIS refutes the claim that the Rule will result in significant environmental impacts. Thus, there is no basis in any event to support requests that the Commission "level" the playing field.

Recounted briefly, those 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 extent of the decrease and increase will be largely determined by the relative prices of natural gas and coal.

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The analysis also demonstrates that the Rule will not in any significant respect affect these overall trends. The analysis shows that if the Rule results in efficiency gains in the electric industry that favors the use of natural gas as a fuel, the effect will be slightly beneficial; total NO_X emissions will be reduced overall by about two percent nationwide below what would otherwise be expected to occur. If the Rule results in efficiency gains that favor the use of coal as a fuel, the Rule is expected to increase NO_X emissions approximately one percent above what would otherwise be expected to occur.

Even analyzing the highly unlikely frozen efficiency case, the analysis demonstrates that the impacts of the Rule will not be great and will not vary significantly from those projected by staff under the assumptions discussed above. This study, utilizing a 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. 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.

All told, this analysis demonstrates 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 under scenarios contrived to maximize emissions under circumstances that the Commission believes to be highly unlikely. This is also true in the near to mid-term. Assuming that any environmental impacts occur, they are years in the future and may well be beneficial.

Thus, contrary to the position taken by those seeking to have the Commission impose mitigation, the Rule will not result in impacts requiring mitigation to level the playing field.

Moreover, as also noted above, EPA has committed to address the existing NO_X transport issue, including the contribution of the Rule, if any, to those impacts. It must be emphasized in this regard that the Northeast has experienced significant air pollution problems for many, many years. Much of this pollution is generated by activities within the affected states and within the affected region; the problem is exacerbated somewhat by the airborne transport of pollutants from upwind areas, including pollutants resulting from the generation of electricity that will occur regardless of any future increase in generation that might result from implementation of the Rule.

Put differently, the pollution problems in the individual states and in the Northeast in general result primarily from economic activities within those states. The airborne transport of pollutants, including pollution resulting from existing electric generation, adds to the existing problem to some degree. The analysis in the FEIS demonstrates that open access may increase the amount of upwind generation by some small increment, and thus increase the downwind NO_X levels by an even smaller incremental amount. On the other hand, depending on the future competitive position of natural gas versus coal, a situation over which the Commission has no control, the Rule may decrease the amount of pollution that would otherwise exist and thus decrease downwind pollution. In any event, the Rule will affect existing trends slightly, if at all.

In recognition of the situation described above, which again is likely to be affected only very slightly, if at all, by the Rule, EPA has committed to address the overall issue of NO_X emissions as part of a comprehensive program developed by EPA and the states. EPA has committed to use its authority under the Clean Air Act to successfully complete the OTAG process. EPA states that it will, if necessary, establish a NO_X cap-and-trade program for the OTAG region through Federal Implementation Plans if some states are unable or unwilling to act in a timely manner.

As discussed in the FEIS, and as noted above, OTAG has efforts underway to develop responses to this problem. For example, OTAG intends to submit its findings regarding ozone transport patterns and its recommendations for mitigation of ozone transport to EPA by April or May 1997. If this process is less than fully successful, the Clean Air Act authorizes EPA to act in a relatively short time-frame to address this problem. EPA has committed to exercise this authority to address the problem.

It must be emphasized that EPA has stated its intent to address the problem regardless of the effects of the Rule. Even if the Rule results in environmental impacts, those incremental impacts will be addressed as part of the comprehensive NO_X regulatory developed by EPA in conjunction with the states.

Thus, EPA has committed to undertake the mitigation sought by the PA Com, NJ BPU and Joint Commenters. The Commission has stated its intent to participate in this process as discussed above. This result negates claims that implementing open access without mitigation will place downwind utilities and the Pennsylvania coal industry at a competitive disadvantage. Accordingly, the requests that the Commission impose mitigation measures to "level" the environmental playing field are denied.

E. Short-Term Consequences of the Rule

The FEIS projects future electric powerplant emissions under a range of assumptions without the Rule (base cases). These results are then compared to what electric powerplant emissions are likely to be under corresponding assumptions with the Rule in place (Rule scenarios). The study utilizes three reporting years: 2000, 2005, and 2010. These reporting years were chosen because they cover a reasonable time frame for the study. Beyond 2010, the ***12454** projections are dependent on too many unforeseeable factors to be meaningful.[FN859]

Although the effects of the Rule will begin to occur when the final Rule is issued, the effects should develop gradually over time. Measurable effects are expected to be clearly observable by the year 2000, though not necessarily fully complete.[FN860]

The FEIS analysis of the Rule scenarios shows that NO_X emissions are expected to decrease significantly between 1993 and 2000. The Competition-Favors-Gas Scenario demonstrates that the Rule will reinforce decreases already present in the base case. Thus, the Rule will enhance underlying environmental improvements. While the Competition-Favors-Coal Scenario demonstrates small emissions increases, NO_X emissions nonetheless continue to decrease from 1993 to 2000. A similar trend is also seen on a regional basis. The Rule does not alter the basic pattern of environmental improvement.[FN861]

Rehearing Requests

New Jersey BPU. The NJ BPU claims that the FEIS fails to recognize possible short-term effects the Rule may have on existing ozone problems in the Northeast, and that the failure to address short-term consequences is of particular importance to nonattainment states who must meet Clean Air Act attainment dates in 1996 and 1999.

Joint Commenters. The Joint Commenters claim that by examining the period between 2000 and 2010, the FEIS fails to analyze near-term impacts and the need for a short-term mitigation strategy. Joint Commenters note that the Rule will be implemented almost immediately, and that changes in generation plant utilization that give rise to the greatest environmental concerns may occur very quickly.

The Joint Commenters are concerned that the FEIS does not consider how projected environmental effects prior to 2000 would impact air quality and Clean Air Act attainment deadlines. The Joint Commenters contest the conclusion that utility NO_X emissions will decline between 1993 and 2000. It states that emissions will increase each year between 1993 and 2000 except in 1996 and 2000, when large NO_X reductions will be implemented pursuant to the Clean Air Act. The Joint Commenters also contend that it is irrelevant whether clean air programs will cause overall emissions to be lower in 2000 than they were in 1993; the relevant question is whether emissions will be higher with Order No. 888 than without it.

The Joint Commenters contend that the data presented in the FEIS for the year 2000 suggest that, if the Rule is considered in isolation, there will be potentially significant short-term emissions increases in the period 1996-2000. It states that the FEIS indicates that implementation of the Rule under the Competition-Favors-Coal Scenario with expanded transmission will lead to an additional 132,000 tons of NO_X emissions in 2000 compared with the frozen efficiency reference case. It contends, assuming a linear increase, that this means there could be an additional 75,000, 94,000 and 113,000 tons of NO_X emissions as a result of the Rule in 1997, 1998, and 1999, respectively.

Commission Conclusion

The Joint Commenters' claims that implementation of the Rule will lead to an additional 132,000 tons of NO_X emissions in the year 2000 in incorrect. As is the case with regard to its assertion above that the Rule will result an additional 315,000 tons of NO_X emissions in 2010, this impact was derived by selectively choosing numbers from the FEIS, comparing two sensitivity cases designed to be unrealistically low and high extremes. The low emissions case is the frozen efficiency case that represents a complete reversal of current industry and regulatory trends that are occurring without the Rule. The high emissions case represents an increase in transmission capacity that cannot reasonably be ascribed to the Rule. As stated in the FEIS, these cases were selected to examine the sensitivity of FEIS findings to certain extreme assumptions maintained by commenters and are not the appropriate cases for determining potential environmental impacts from the Rule.

Moreover, we note that the Joint Commenters reference increases from the Rule without noting equally likely decreases. Even with the lower emissions resulting from the unrealistic frozen efficiency case, the FEIS finds decreases in emissions from the Rule when competitive forces lead to greater efficiency for natural gas generation compared to coal.

The Commission has analyzed the Rule and found that its impacts will be insignificant. We also note that even if the Rule were to result in short-term emission increases, EPA has signaled its willingness to address the transport of pollutants in a timely fashion. As discussed above, EPA has concluded that any emissions increases associated with the Rule should be addressed as part of a comprehensive NO_X emissions control program developed by EPA and the states under mechanisms available under the Clean Air Act. This approach includes support for OTAG efforts to develop emissions reduction strategies. OTAG plans to submit its findings and mitigation recommendations to EPA by April or May 1997. As discussed above, EPA has issued a notice of intent to adopt by summer 1997 a rule that would require state implementation plan measures to ensure that emission reductions are achieved as needed to prevent significant transport of ozone pollution across state boundaries in the Eastern United States. EPA is contemplating establishing deadlines for state implementation plan submittals ranging from six months to 18 months following the date of publication of its notice of final rulemaking.

The instant Rule will affect the existing NO_X transport issue very little, if at all. As stated in Order No. 888, the Rule is not the appropriate vehicle for resolving this debate. The appropriate regulatory mechanism for addressing the overall NO_X problem, 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 noted, EPA has committed to implement this approach. Even if there are slight environmental impacts associated with the Rule, they are better and more effectively addressed as part of a comprehensive NO_X regulatory program.

G. Cost Benefit Analysis

"The legal and policy cornerstone" of Order No. 888 "is to remedy undue discrimination in access to the monopoly owned transmission wires that control whether and to whom electricity can be transported in interstate commerce." [FN862] As reiterated in the FEIS, the purpose of the Rule is to increase access to non-discriminatory transmission services and thereby increase competition in wholesale electric markets.[FN863]

The FEIS states that the Rule will give wholesale power customers a greater opportunity to obtain competitively priced electricity. Competition will create benefits through better use of existing assets and institutions, new market mechanisms, technical innovation, and less rate distortion. ***12455** Only the first—better use of existing assets and institutions—was estimated quantitatively: approximately $3.8 to $5.4 billion per year. The FEIS also discusses other benefits that cannot be quantified but may be large. Based on the experience of, for example, the natural gas and telecommunications industries, the Commission opined that the other three are likely to increase industry efficiency—and benefits—substantially.[FN864]

As described elsewhere in this order, the FEIS also discusses extensively possible environmental effects (i.e., costs) of the Rule. It concludes that the Rule could raise or lower national emissions slightly, but will not have a significant effect on the environment.

Rehearing Requests

The Joint Commenters contend that the analysis of projected benefits from the Rule appears to be inadequately substantiated and uses assumptions that are inconsistent with those used to reach a finding of no significant impact on environmental issues. Although Joint Commenters do not challenge the conclusion that Order No. 888 will result in economic benefits, it states that the benefits identified in the FEIS are inadequately substantiated and do not reflect a balanced analysis. It claims that courts have held that when economic development is the selling point or raison d'etre of an action NEPA requires the agency to provide a specific comparison of economic benefits versus environmental costs. It concludes that the analysis of the economic benefits of Order No. 888 is tipped in favor of benefits, especially when contrasted with the analysis of projected environmental impacts.

Joint Commenters state that the conclusion that benefits will range from $3.76 to $5.37 billion per year is not properly documented and cannot be relied upon as justification for implementing the Rule without mitigation. It contends that the Commission is counting benefits from changes that are unrelated to the Rule, such as benefits resulting from higher plant availability factors. Joint Commenters claim that this assertion appears to be inconsistent with industry reactions to competition to date. The same is true of planning reserve margins. It states that key assumptions used to define the operating savings, particularly fuel price assumptions, are unreasonable. It adds that these savings are the ones that give rise to adverse environmental effects due to increased utilization of existing low-cost coal generation. Therefore, it is inappropriate to count these economic benefits without examining the offsetting environmental costs, which increase as the level of the asserted benefits increase.

Finally, Joint Commenters assert that the FEIS does not address potential costs associated with implementing the Rule. These include costs to the Northeast and other regions of additional environmental compliance and the impact on public health of additional pollution; socioeconomic costs associated with utility downsizing; potential adverse effects on nuclear power plant operations from competition; or potential regulatory costs associated with compliance with Order No. 888. Thus, Joint Commenters conclude that the FEIS does not provide a basis for calculating the net benefits of Order No. 888. It also states that the FEIS does not provide a basis for concluding that the potential savings will exceed the additional costs associated with increased use of coal generation without mitigation.

Commission Conclusion

The fulcrum of Joint Commenters' challenge is its claim that when economic development is the selling point of a proposed action, NEPA requires the agency to provide a specific comparison of economic benefits versus environmental costs. The Joint Commenters do not challenge the conclusion that the Rule will result in economic benefits. Rather, it claims that the benefits identified in the FEIS are not adequately substantiated and do not reflect a balanced analysis of benefits versus costs. This argument is made to further the claim, asserted by Joint Commenters in various forms, that the Commission must impose mitigation to "level" the playing field.

The Joint Commenters' argument misapprehends the purpose of Order No. 888, the role a cost-benefit analysis plays in an EIS, and the reasons for the Commission's discussion of the economic benefits of the Rule.

The purpose of the Rule is not to foster economic development, although the Commission anticipates that this will be a salutary effect of open access. The purpose of the Rule is to promote competition in the wholesale bulk power markets by remedying undue discrimination in access. The fact that the Rule will create benefits through better use of existing assets and institutions, new market mechanisms, technical innovation, and less rate distortion is a consequence rather than the purpose of the Rule.

The Joint Commenters also mistake the role a cost-benefit analysis plays in an EIS. The CEQ regulations implementing NEPA set forth the requirements pertaining to a cost-benefit analysis at 40 CFR 1502.23 (1996):

If a cost-benefit analysis relevant to the choice among environmentally different alternatives is being considered for the proposed action, it shall be incorporated by reference or appended to the statement as an aid in evaluating the environmental consequences. To assess the adequacy of compliance with section 102(2)(B) of the Act the statement shall, when a cost-benefit analysis is prepared, discuss the relationship between that analysis and any analyses of unquantified environmental impacts, values, and amenities. For purposes of complying with the Act, the weighing of the merits and drawback of the various alternatives need not be displayed in a monetary cost-benefit analysis and should not be when there are important qualitative considerations. In any event, an environmental impact statement should at least indicate those considerations, including factors not related to environmental quality, which are likely to be relevant and important to a decision.

Thus, the function of a cost-benefit analysis is to assist in the choice among environmentally different alternatives. As discussed above, the Commission's recitation in the FEIS of the anticipated economic benefits of the Rule is not undertaken to assist in the choice among environmental different alternatives. The FEIS discusses the expected economic benefits of the Rule in a broader context, noting that "[t]he most important socioeconomic effect of the proposed rule is expected to be potentially large benefits to ratepayers and to the economy as a whole."[FN865]
The authorities cited by the Joint Commenters do not alter this conclusion. The Commission is not using the benefits of the Rule as a selling point to go forward with the action while ignoring disadvantages that might flow from it. The FEIS fully examines the impacts of the Rule and concludes that implementation of the Rule will not result in adverse environmental consequences. The Joint Commenters disagreement is with this substantive conclusion, not with the alleged failure to conduct a cost-benefit analysis. Their disagreement does not mean, however, that the Commission has ignored the disadvantages that Joint Commenters assert would flow from the Rule. In brief, as discussed throughout the FEIS, Order No. 888, and this order on rehearing, the Commission has examined the impacts of the Rule and ***12456** concluded that it will not result in environmental harms.

Thus, even under the broadest possible interpretation of the cost-benefit analysis requirement, the Commission has evaluated the benefits of the Rule against its impacts and concluded that the benefits are likely to be significant and that the impacts are likely to be insignificant.[FN866]

The D.C. Circuit rejected the underlying argument advanced here by the Joint Commenters in Public Utilities Commission of the State of California v. FERC, 900 F.2d 269 (D.C. Cir. 1990). There, California contended that the Commission did not comply with NEPA in granting an Optional Expedited Certificate (OEC) permitting construction of a natural gas pipeline. California argued that the Commission could not have balanced the adverse environmental effects against the need for the project because under the OEC procedures it made no particularized inquiry into the economic benefits of the pipeline. The court responded that:

Two of our cases speak of a NEPA requirement that "responsible decisionmakers * * * fully advert[] to the environmental consequences" of a proposed action and "decide[] that the public benefits * * * outweigh[] the [] environmental costs." Illinois Commerce Comm'n v. ICC, 848 F.2d 1246, 1259 (D.C.Cir.1988); Jones v. District of Columbia Redevelopment Land Agency, 499 F.2d 502, 512 (D.C.Cir.1974). Though the Commission engaged in an "individualized consideration and balancing of environmental factors," as required by Calvert Cliffs' Coord. Comm. v. United States Atomic Energy Comm'n, 449 F.2d 1109, 1115 (D.C.Cir.1971), its evaluation of the nonenvironmental aspects of the pipeline was not individualized. As to them the Commission stated that "the interests of the public articulated in our adoption of the optional certificate process [i.e., Order No. 436] outweigh, on balance, the relatively insubstantial environmental harm which will result from a properly mitigated WyCal Pipeline." Mojave Pipeline Co., 46 FERC at 61,168 (emphasis added).

California's insistence on a particularized assessment of non-environmental features finds no support in the statutory language. See NEPA §102, 42 U.S.C. §4332 (requiring the agency to consider a variety of environmental, not economic, factors). Its theory would disable any number of efforts at streamlining the resolution of regulatory issues that have nothing to do with the environment. An agency's primary duty under the NEPA is to “take[] a 'hard look' at environmental consequences.” Kleppe v. Sierra Club, 427 U.S. 390, 410 n. 21, 96 S.Ct. 2718, 2730 n. 21, 49 L.Ed.2d 576 (1976). We will not extend that statute well beyond its realm so as to create unnecessary conflicts with others.[[FN867]]

Thus, an agency need not conduct a particularized assessment of the nonenvironmental features of a proposal, in particular its economic benefits or costs. The Commission nonetheless examined the potential costs of the Rule and determined that those costs will be very small and may be positive instead of negative in any event. The Commission has also examined the benefits of the project and concluded that it will have substantial benefits. Accordingly, the request for rehearing is denied.

H. Socioeconomic Impacts

The FEIS examines the socioeconomic impacts of the Rule, including whether the Rule will result in regional shifts in economic activity (especially electric generation and coal mining).[FN868] The analysis demonstrates that an effect of a more competitive industry may be increased use of existing electric generating facilities. Consequently, it seems likely that those who supply fuel to existing plants could see a higher demand for their output as a result of the Rule. The FEIS notes that this might not be true in all places, however, if factors such as changes in environmental standards work in the opposite direction. The FEIS does not attempt to measure local or site-specific impacts given the speculative nature of such impacts.

The FEIS also notes that open access could lead to changes in employment patterns, but concludes that it is highly uncertain, however, which changes are likely to result from restructuring.[FN869] The FEIS notes that some changes should lead to cost reductions that will tend to increase jobs in other industries, as well as lower rates for other consumers. Lower power bills can make other industries more competitive and lead them to increase employment.

The FEIS also notes that the Rule is only part of the restructuring currently affecting the industry. Employment in traditional utilities has fallen in recent years. Developments at the state and federal levels will increase competition in the industry even without the Rule. Given the highly uncertain nature of future developments in the electric industry and the complex, dynamic economic issues involved, the FEIS concludes that any quantitative estimate of changes in employment (or even the direction of change) would be highly speculative.

Rehearing Requests

The PA Com claims that socioeconomic impacts that may result from regional economic shifts occurring as a result of the Rule are not adequately discussed in the FEIS. It states that Order No. 888 contemplates a reduction in the amount of coal-fired generation, and that if Pennsylvania generation is shut-down or dispatched less often in favor of generation that is not subject to the same environmental costs and requirements, less Pennsylvania coal will be mined.

The PA Com states that Pennsylvania produces 60 million tons of coal a year, most of which is purchased by Pennsylvania electric utilities. It alleges that the Pennsylvania coal industry provides 9,200 direct mining jobs and 9,500 support service jobs. Coal sales contribute $1.5 billion to the Pennsylvania economy each year and provide an annual payroll of $600 million. The PA Com adds that if coal production declines, the state may curtail efforts to reclaim abandoned mines and coal refuse piles.

The PA Com also contends that social obligations now borne by transmission owning utilities—demand side management programs, integrated resource planning, low-income assistance programs, and federal environmental mandates—have an impact upon price and the market for power, and that utilities might view these obligations as an impediment to competition. It claims that third parties who wish to use the transmission system may balk if they are required to contribute to those social goals.

Finally, the PA Com claims that functional unbundling, open access on a comparability basis, and increased competition may impact reliability of service. It states that it is concerned that reliability is subordinate to economic concerns, and that if reliability is not an articulated foundation of FERC actions, system reliability may suffer. It concludes that the FEIS assumes that reliability will be enhanced by open access, but that this assumption is not adequately explained.

Commission Conclusion

The PA Com's concerns as to the alleged socioeconomic impacts of the Rule are based on a series of tenuous economic "what-ifs." It assumes that the Rule will result in a reduction in Pennsylvania generation. It assumes from this that less coal will be mined in ***12457** Pennsylvania and that Pennsylvania will suffer adverse economic consequences. It then assumes that this might lead Pennsylvania to curtail efforts to reclaim abandoned surface and strip mines. No basis has been shown to support the elements in this chain of assumptions. The effects Pennsylvania fears are simply too speculative to assess at this time.

Moreover, the PA Com's concerns stem from the postulated economic impacts of the Rule rather than from the alleged impact of the Rule on the physical environment. Thus, its concerns are not proper for consideration in an EIS. The CEQ states that socioeconomic impacts alone do not warrant study in an EIS.[FN870] The CEQ also states that an agency must make reasonable efforts in preparing an EIS to acquire relevant information concerning socioeconomic impacts when economic or social and natural or physical environmental effects are interrelated.[FN871] If such effects are not interrelated, they need not be considered. In this case, the PA Com's concerns stem from what it anticipates will be the economic impact of the Rule on Pennsylvania, and not from the natural or physical environmental impacts of the Rule. Thus, these concerns are not proper for consideration in an EIS.[FN872]

The approach to such issues is perhaps best symbolized by the Supreme Court's decision in Metropolitan Edison Co. v. People Against Nuclear Energy, 460 U.S. 766 (1983). In that case, People Against Nuclear Energy (PANE) contended that NEPA required the Nuclear Regulatory Commission to consider whether restarting the Three Mile Island-1 nuclear reactor after the accident at the Three Mile Island-2 reactor would "cause both severe psychological health damage to persons living in the vicinity, and serious damage to the stability, cohesiveness, and well-being of the neighboring communities."[FN873] The court rejected this argument:

The theme of §102 is sounded by the adjective "environmental": NEPA does not require the agency to assess every impact or effect of its proposed action, but only the impact or effect on the environment. If we were to seize the word "environmental" out of its context and give it the broadest possible definition, the words "adverse environmental effects" might embrace virtually any consequence of a governmental action that someone thought "adverse." But we think the context of the statute shows that Congress was talking about the physical environment—the world around us, so to speak. NEPA was designed to promote human welfare by alerting governmental actors to the effect of their proposed actions on the physical environment.

* * * Thus, although NEPA states its goals in sweeping terms of human health and welfare, those goals are ends that Congress has chosen to pursue by means of protecting the physical environment.[[FN874]]

Even though it was not incumbent upon it to do so, the Commission analyzed the concerns raised by the PA Com to the extent it was practicable to do so. The impacts of the Rule on future levels of coal-fired generation in Pennsylvania or on employment in a specific geographic area or in a specific economic sector are influenced by a virtually unlimited roster of other factors, and thus are too speculative to be useful.

I. Coastal Zone Management Act

Order No. 888 found that the Rule does not constitute a federal activity subject to compliance with the Coastal Zone Management Act, 16 U.S.C. §1451 et seq. (CZMA).[FN875] Order No. 888 concluded that:

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. Consequently, pursuant to 15 CFR 930.35(b), Connecticut has in any event waived its right to request a consistency determination for this rulemaking. [[FN876]]

Rehearing Requests
The Connecticut Department of Environmental Protection (Connecticut DEP) requests that the Commission determine whether Order No. 888 is a federal activity requiring a coastal consistency determination, determine whether the Rule is consistent with Connecticut's coastal management plan (CMP), and consider the impacts that promoting competition and altering transmission and generation patterns may have on water quality in the Long Island Sound. The Connecticut DEP also requests that the Commission mitigate potential increases in nitrogen and sulphur oxide emissions occurring as a result of the Rule.

Commission Conclusion
On August 20, 1996, the Commission responded to the Connecticut DEP, issuing a consistency determination and a negative determination. The response notes that the FEIS focuses on the concerns raised by the Connecticut DEP and concludes that the most important factor determining changes in future emissions is the relative competitive ***12458** position (e.g., price) of coal and natural gas. Depending on the relative prices of these fuels, emissions from electric generating facilities may increase slightly or decrease slightly. Regional effects, including those for the region encompassing Connecticut, are projected to be similar. The response also notes that these estimates fall within the "noise" level of the model. That is, they are smaller than the uncertainties in the science underlying the model.

Thus, the response concludes that the Rule will not have an effect on the land and water uses or natural resources of Connecticut. Accordingly, the Commission issued a negative determination pursuant to the regulations implementing the CZMA, 15 CFR 930.35(d). [FN877]

The response also notes that even if the Rule were to have a minimal effect on Connecticut's coastal zone, the Rule is consistent to the maximum extent practicable with the enforceable policies of the Connecticut Coastal Management Plan (Connecticut Plan). The Connecticut Coastal Management Act and supporting policies which provide the basis for the Connecticut Plan require that activities be consistent with the Clean Air Act. The Connecticut Plan provides that activities are not assumed to directly affect Connecticut, and thus do not require a consistency determination, unless they "would result in a significant change in air or water quality."

The August 20, 1996 response concludes that the Rule is consistent with the requirements of the Clean Air Act and will not result in a significant change in air or water quality in Connecticut. In fact, depending on the future prices of fuel, the Rule is equally likely to improve air quality over Connecticut and decrease emissions deposition in the waters of the Long Island Sound. Thus, the Rule is consistent with the Connecticut Plan regardless of any slight effects it may have.

Finally, the response notes that the action sought by Connecticut DEP to ensure consistency with the Connecticut Plan has already been taken in any event. Following issuance of the Rule, EPA, the federal agency charged with implementing the Clean Air Act, stated that it would use its authority to comprehensively address NO_X emissions, including any potential incremental increases in emissions that might result from implementation of the Rule, in the 37-state region that makes up the Ozone Transport Assessment Group. This region includes Connecticut. In an Order issued May 29, 1996, the Commission agreed to examine the issue of mitigation of the impacts, if any, of the Rule in the event that EPA and the OTAG states are unsuccessful in addressing the NO_X problem.

Thus, the FEIS demonstrates that the Rule will not have an effect on any land or water use or natural resource of Connecticut's coastal zone. Moreover, the Rule is consistent with Connecticut's CMP. Finally, EPA and the Commission have taken the action sought by Connecticut DEP to ensure consistency with Connecticut's CMP. These actions fully address Connecticut DEP's coastal zone concerns.

VI. Regulatory Flexibility Act Certification

The Regulatory Flexibility Act (RFA)[FN878] requires rulemakings to either contain a description and analysis of the effect that the proposed or final rule will have on small entities or to contain 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 Final Rules, the Commission certified that the final rules would not impose a significant economic impact on a substantial number of small entities.[FN879]

NRECA and SBA question this certification.[FN880] According to NRECA there are about 1,000 rural electric cooperatives and 2,000 municipal electric systems, most of which meet the RFA definition of small electric entity. NRECA states that the Commission has imposed open access, OASIS and code of conduct requirements on non-public utilities. NRECA maintains that if non-public utilities do not meet these requirements, “they will not retain access over the long-term to the nation's bulk power transmission grid—access they must have if they wish to stay in business.”[FN881]

NRECA also contends that the stranded cost issue will affect small non-public utilities “any time a non-public utility is required to render reciprocal transmission service, and loses a customer as a result of rendering that service, or a TDU [transmission dependent utility] loses a customer to an open access public utility transmission provider.”[FN882] NRECA asserts that both the OASIS Final Rule and the Capacity Reservation Tariff NOPR[FN883] will substantially burden small non-public utilities.[FN884] NRECA further maintains that the Commission's waiver provisions will not alleviate the burden on small utilities. It states that filing a waiver request with the Commission is burdensome for small utilities.

SBA states that 30 percent (50 of 166) of public utilities are small under the SBA's definition of a small public electric utility.[FN885] SBA contends that if, as the Commission has found, 11 percent of public utilities are small, the Final Rules will still affect a significant number of small public utilities.

SBA challenges the Commission's reliance on Mid-Tex Electric Cooperative, Inc. v. FERC.[FN886] It contends that the Commission should have analyzed the probable effect of the Final Rules on small businesses by projecting, perhaps on the model of the deregulated ***12459** telecommunications industry, how many small electric utilities, as the SBA defines that term, would enter the deregulated electric utility market.

Commission Conclusion

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

1. Public Utilities

In the Open Access Final Rule we determined that the Rule applies:

to public utilities that own, control or operate interstate transmission facilities, not to electric utilities per se. The total number of public utilities that, absent waiver, would have to have open access tariffs on file is 166. Of these, only 50 public utilities dispose of 4 million MWh or less per year. Eliminating those utilities that are affiliates of other utilities whose sales exceed 4 million MWh or less per year, or are not independently owned, 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.[FN887]

We do not agree with the SBA that 11 percent of all of the public utilities that would have to file open access tariffs with us is a significant number. Also, the SBA has overlooked several of the other findings we made as to the possible effect of the Open Access Final Rule on small public utilities. As we noted, of the 19 public utilities that would come within the SBA's definition of small electric utility, five have already filed open access tariffs with the Commission, so that the effect of the Open Access Rule on these utilities should not be significant.[FN888]

Further, the Commission is specifying the non-rate terms and conditions of the tariffs that public utilities must file, so all public utilities need to do is file a rate, and the small public utilities with open access tariffs already on file with us need not even do that. They may elect to continue service under the Open Access Final Rule's non-rate terms and conditions at their existing rates. In our Final Rule we estimated that the cost for filing a rate would not, on average, exceed one half of one percent of total annual sales for small electric utilities,[FN889] which is not a significant economic impact.

We disagree with SBA that our reliance on Mid-Tex is misplaced. In Mid-Tex, the court accepted the Commission's conclusion that virtually all of the public utilities that the Commission regulates do not fall within the RFA's meaning of the term "small entities." Mid-Tex involved a rule that applies to all public utilities. The Open Access Final Rule applies to only those public utilities that own, control or operate interstate transmission facilities, which are a subset of the group of public utilities for which Mid-Tex did not require the preparation of a regulatory flexibility analysis.[FN890]

SBA attempts to distinguish Mid-Tex by postulating that the Commission should have attempted to predict how many new entrants into a deregulated market would be small electric utilities, within the SBA's meaning of that term. Mid-Tex held just the opposite, deciding squarely that an agency need only consider the businesses that a regulation directly affects.[FN891] There is no precedent for SBA's suggestion that the Commission must engage in a hypothetical projection of how many entrants likely to enter a deregulated market may be small electric utilities, and we know of no satisfactory way of making such a projection. Entry into the telecommunications industry, which the SBA offers as a model, involves very different costs, distribution and marketing patterns and entirely different technology. There is no way, from looking at what has happened in the telecommunications industry, that the Commission could project, with any degree of accuracy, how many small electric utilities, if any, will enter the market following the effective date of the Final Open Access Rule.

Finally, SBA overlooks, and NRECA unreasonably discounts, the effect that the Commission's waiver rules have on relieving the burden of the Open Access Final Rule on small entities.[FN892] The Commission has recently issued a number of orders waiving the requirements of the Open Access Final Rule for a number of small electric utilities.[FN893] As these cases show, the Commission is carefully evaluating the effect of the Open Access Final Rule on small electric utilities and is granting waivers where appropriate, thus mitigating the economic effect of that rule on small entities. Indeed, as we noted in Order No. 888, 5 small public utilities previously had filed open access tariffs, and we have since, in the cases cited above, granted waivers to approximately 17 small public utilities.[FN894]

2. Non-Public Utilities

We disagree with NRECA's argument that Order No. 888 imposes burdens upon non-public utilities. As we noted in the Final Rule, we do not have jurisdiction to regulate non-public utilities' rates, terms and conditions of transmission service under sections 205 and 206 of the FPA, and there is no requirement in Order No. 888 that non-public utilities file open access tariffs.[FN895]

In addition, under the waiver provisions of the Open Access Final Rule, small non-public utilities may seek waiver from the reciprocity provision. As reflected in the cases cited above, the Commission has granted waivers of the reciprocity provision to 10 small non-public electric utilities and issued disclaimers of jurisdiction with respect to 19 small electric utilities, thus mitigating the effect of the Open Access Final Rule on small non-public electric utilities.

B. Docket No. RM94-7-000 (Stranded Cost Final Rule)

1. Public Utilities

No rehearing requests addressed this matter.

2. Non-Public Utilities

In Order No. 888, the Commission indicated that the Stranded Cost Final Rule will not impose a significant economic impact on a substantial number of non-public utility small entities because 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. NRECA counters that the stranded cost issue will "arise: any time a non-public utility is required to ***12460** render reciprocal transmission service, and loses a customer as a result of rendering that service, or a TDU loses a customer to an open access public utility transmission provider."[FN896] NRECA submits that the adverse economic impact on small non-public utilities will "arise" from the stranding of costs, not from the utilities' participation in proceedings at the Commission, and that the Commission "cannot in good conscience fail at least to probe the potential adverse economic impact on small non-public utilities of the stranded costs they incur as a direct result of Order No. 888."

Notwithstanding NRECA's argument that small non-public utilities may experience stranded costs outside of a section 211/212 proceeding, as we explain in Section IV.J.1, supra, our jurisdiction over the recovery of stranded costs by non-public utilities, and thus our ability to permit an opportunity for recovery of such costs, is limited by statute. With the exception of our section 210 interconnection and sections 211-212 transmission rate jurisdiction, we do not have jurisdiction over the rates of non-public utilities. Because the stranded cost issue would primarily arise as to non-public utilities over which the Commission has jurisdiction 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,[FN897] we concluded that the Stranded Cost Final Rule will not impose a significant economic impact on a substantial number of non-public utility small entities.

Because the Commission does not have rate jurisdiction over non-public utilities other than through sections 210, 211 and 212, the Commission does not have the authority to allow them to recover stranded costs other than through rates set under section 212. However, we clarify that nothing in the Final Rule was intended to preclude non-public utilities from including stranded cost provisions in voluntary reciprocity tariffs or from otherwise recovering stranded costs under applicable law. Thus, a non-public utility that chooses voluntarily to offer an open access tariff for purposes of demonstrating that it meets the reciprocity provision can include a stranded cost provision in its tariff. However, adjudication of any stranded cost claims under that tariff is not subject to the Commission's jurisdiction.[FN898] If a non-public utility wishes to recover stranded costs pursuant to a tariff or otherwise, it can seek to do so subject to the review of the appropriate regulatory or judicial authority.

VII. Information Collection Statement

Order No. 888 contained an information collection statement for which the Commission obtained approval from the Office of Management and Budget (OMB).[FN899] Given that this order on rehearing makes only minor revisions to Order No. 888, none of which is substantive, OMB approval for this order will not be necessary. However, the Commission will send a copy of this order to OMB, for informational purposes only.

The information reporting requirements under this order are virtually unchanged from those contained in Order No. 888. Interested persons may obtain information on the reporting requirements by contacting the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426 [Attention Michael Miller, Information Services Division, (202) 208-1415], and the Office of Management and Budget [Attention: Desk Officer for the Federal Energy Regulatory Commission (202) 395-3087].

VIII. Effective Date

Changes to Order No. 888 made in this order on rehearing will become effective on May 13, 1997.

List of Subjects 18 CFR Part 35

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

By the Commission. Commissioners Hoecker and Massey dissented in part with separate statements attached.

Lois D. Cashell,

Secretary.

In consideration of the foregoing, the Commission amends part 35, 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 § 35.26
2. Part 35 is amended by revising §35.26 to read as follows:
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 that subsequently becomes, either directly or through another wholesale transmission purchaser, 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 means the transmission of electric energy sold, or to be sold, at wholesale in interstate commerce or ordered pursuant to section 211 of the Federal Power Act (FPA).

(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 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.

(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 ***12461** 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 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) through (vii) of this section must demonstrate that:

(i) It incurred costs to provide service to a 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 the utility; and

(iii) The stranded costs are derived using the following formula: Stranded Cost Obligation = (Revenue Stream Estimate—Competitive Market Value Estimate) x 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 ***12462** 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 costs to provide service to 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.

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

Appendix A—List of Petitioners

Docket Nos. RM95-8-001 and RM94-7-002

Abbreviation	Petitioner
1. AEC & SMEPA	Alabama Electric Cooperative, Inc. and South Mississippi Electric Power Association.
2. AEP	Operating Companies of the American Electric Power System.
3. AL Com	Alabama Public Service Commission.
4. Allegheny	Allegheny Power Service Corporation.
5. AL Municipal	Alabama Municipal Electric Authority.
6. American Forest & Paper	American Forest & Paper Association.
7. AMP-Ohio	American Municipal Power-Ohio, Inc. and Indiana Municipal Power Agency.
8. Anaheim	Cities of Anaheim, Azusa, Banning, Colton and Riverside, California.
9. APPA	American Public Power Association.
10. AR Com	Arkansas Public Service Commission.
11. Arkansas Cities	Arkansas Cities and Farmers Electric Cooperative.

12. Associated EC	Associated Electric Cooperative, Inc.
13. Atlantic City	Atlantic City Electric Company.
14. Basin EC	Basin Electric Power Cooperative.
15. 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.
16. BPA	Bonneville Power Administration.
17. Cajun	Ralph R. Mabey, Chapter II Trustee for Cajun Electric Power Cooperative, Inc.
18. California DWR	California Department of Water Resources.
19. Carolina P&L	Carolina Power & Light Company.
20. CCEM	Coalition for a Competitive Electric Market (consisting of Coastal Electric Services Company, Destec Power Services, Inc., Electric Clearinghouse, Inc., Enron Power Marketing, Inc., Equitable Power Services Company, KCS Power Marketing, Inc., MidCon Power Services Corp. and Vitol Gas & Electric Services, Inc).
21. Centerior	Centerior Energy Corporation.
22. Central Illinois Light	Central Illinois Light Company.
23. Central Minnesota Municipal	Central Minnesota Municipal Power Agency.
24. Central Montana EC	Central Montana Electric Power Cooperative, Inc.
25. Cleveland	Cleveland Public Power.
26. CO Consumers Counsel	Colorado Office of Consumer Counsel.
27. Coalition for Economic Competition	Coalition for Economic Competition Consisting of Consolidated Edison Company of New York, Inc., General Public Utilities Corporation, Illinois Power Company, Long Island Lighting Company, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Northeast Utilities, and Rochester Gas and Electric Corporation.
28. ConEd	Consolidated Edison Company of New York, Inc.
29. Connecticut DEP	State of Connecticut Department of Environmental Protection.
30. Consumers Power	Consumers Power Company.
31. Cooperative Power	Cooperative Power.

32. CSW Operating Companies	Central Power and Light, West Texas Utilities Company, Public Service Company of Oklahoma and Southwestern Electric Power Company.
33. CVPSC	Central Vermont Public Service Corporation.
34. Dairyland	Dairyland Power Cooperative.
35. Dalton	City of Dalton, Georgia.
36. Detroit Edison	Detroit Edison Company.
37. Dispute Resolution	Communications and Energy Dispute Resolution Associates.
38. Duquesne	Duquesne Light Company.
39. EEI	Edison Electric Institute.
40. EGA	Electric Generation Association.
41. El Paso	El Paso Electric Company.
42. ELCON	Electricity Consumers Resource Council, American Iron and Steel Institute, Chemical Manufacturers Association and Council of Industrial Boiler Owners.
43. Entergy	Entergy Services, Inc.
44. EPRI	Electric Power Research Institute.
45. FL Com	Florida Public Service Commission.
46. Florida Power Corp	Florida Power Corporation.
47. FMPA	Florida Municipal Power Agency
48. FPL	Florida Power & Light Company.
49. Freedom Energy Co	Freedom Energy Corporation, LLC.
50. Hoosier EC	Hoosier Energy Rural Electric Cooperative.
51. IA Com	Iowa Utilities Board.
52. IL Com	Illinois Commerce Commission.
53. IL Industrials	Illinois Industrial Energy Consumers.
54. Illinois Power	Illinois Power Company.
55. IMPA	Indiana Municipal Power Agency.
56. IN Com	Indiana Utility Regulatory Commission.
57. IN Consumer	Indiana Office of Utility Consumer Counselor.
58. Indianapolis POL	Indianapolis Power & Light Company.

59. IN Industrials	Citizens Action Coalition of Indiana, Inc., Indiana Industrial Energy Consumers, Inc. and Indianapolis Power & Light Company.
60. Joint Commenters	Joint Commenters Supporting Clear Air and Fair Corporation.
61. KCPL	Kansas City Power & Light Company.
62. LEPA	Louisiana Energy and Power Authority.
63. Local Furnishing Utilities	Local Furnishing Utilities (Long Island Lighting Company, Nevada Power Company, San Diego Gas & Electric Company and Tuscon Electric Power Company).
64. MA Municipals	Twenty Four Massachusetts Municipals.
65. Maine Public Service	Maine Public Service Company.
66. MI Com	Michigan Public Service Commission and New Hampshire Public Utilities Commission.
67. Michigan Systems	Michigan Public Power Agency, Michigan South Central Power Agency, and Wolverine Power Supply Cooperative, Inc.
68. Minnesota P&L	Minnesota Power & Light Company.
69. MN DPS	Minnesota Department of Public Service and Minnesota Public Utilities Commission.
70. MO/KS Coms	Missouri Public Service Commission and Kansas Corporation Commission.
71. Montana Power	Montana Power Company.
72. Montana-Dakota Utilities	Montana-Dakota Utilities Company.
73. Multiple Intervenors	Multiple Intervenors.
74. NARUC	National Association of Regulatory Utility Commissioners.
75. NASUCA	National Association of State Utility Consumer Advocates.
76. NCMPA	North Carolina Municipal Power Agency Number 1.
77. NE Public Power District	Nebraska Public Power District.
78. NIMO	Niagara Mohawk Power Corporation.
79. NJ BPU	New Jersey Board of Public Utilities.
80. North Jersey	North Jersey Energy Associates.
81. NRECA	National Rural Electric Cooperative Association.
82. NU	Northeast Utilities Service Company.

83. Nuclear Energy Institute	Nuclear Energy Institute.
84. Nucor	Nucor Corporation.
85. NWRTA	Northwest Regional Transmission Association.
86. NY AG	New York State Attorney General.
87. NY Com	Public Service Commission of the State of New York.
88. NY Municipals	Municipal Electric Utilities Association of New York States.
89. NY Utilities	Consolidated Edison Company of New York, Inc., Long Island Lighting Company, New York State Electric & Gas Corporation, and Rochester Gas and Electric Corporation.
90. NYPP	New York Power Pool.
91. NYSEG	New York State Electric & Gas Corporation.
92. Occidental Chemical	Occidental Chemical Corporation.
93. Oglethorpe	Oglethorpe Power Corporation.
94. OH Com	Public Utilities Commission of Ohio.
95. OH Consumers' Counsel	Ohio Office of Consumers' Counsel.
96. Ohio Valley	Ohio Valley Electric Corporation and Indiana-Kentucky Electric Corporation.
97. Oklahoma G&E	Oklahoma Gas and Electric Company Inc.
98. Ontario Hydro	Ontario Hydro.
99. PA Com	Pennsylvania Public Utility Commission.
100. PA Coops	Pennsylvania Rural Electric Association and Allegheny Electric Cooperative, Inc.
101. PA Munis	Pennsylvania Municipal Electric Association.
102. PacifiCorp	PacifiCorp.
103. PSE&G	Public Service Electric and Gas Company.
104. PSNM	Public Service Company of New Mexico.
105. Public Service Co of CO	Public Service Company of Colorado.
106. Puget	Puget Sound Power & Light Company.
107. Redding	City of Redding, California.
108. San Francisco	City and County of San Francisco.

109. Santa Clara	City of Santa Clara, California.
110. SBA	United States Small Business Administration, Office of Advocacy.
111. SC Public Service Authority	South Carolina Public Service Authority.
112. SoCal Edison	Southern California Edison Company.
113. Southern	Southern Company Services, Inc.
114. Southwestern	Southwestern Public Service Company.
115. Speciality Steel	Speciality Steel Industry of North America.
116. Suffolk County	Suffolk County (New York) Electric Agency.
117. SWRTA	Southwest Regional Transmission Association
118. Tallahassee	City of Tallahassee, Florida.
119. TANC	Transmission Agency of Northern California.
120. TAPS	Transmission Access Policy Study Group.
121. TDU Systems	Transmission Dependent Utility Systems.
122. Texaco	Texaco Inc.
123. Tucson Power	Tucson Electric Power Company.
124. Turlock	Turlock Irrigation District.
125. TX Com	Public Utility Commission of Texas.
126. Umatilla EC	Umatilla Electric Cooperative.
127. Union Electric	Union Electric Company.
128. Utilities For Improved transition	Utilities For an Improved Transition (consisting of Associated Electric Cooperative, Inc., Boston Edison Company, Central Vermont Public Service Corporation, Montaup Electric Company, Wisconsin Electric Power Company, and Wisconsin Public Service Corporation).
129. VA Com	Staff of the Virginia State Corporation Commission.
130. Valero	Valero Power Services Company.
131. VEPCO	Virginia Electric and Power Company.
132. VT DPS	Vermont Department of Public Service.
133. Wabash	Wabash Valley Power Association, Inc.
134. Washington Water Power	Washington Water Power Company.
135. WI Com	Public Service Commission of Wisconsin.

136. Wisconsin Municipals	Municipal Electric Utilities of Wisconsin.
137. WY Com	Public Service Commission of Wyoming.

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I. Common Service Provisions

1 Definitions

1.1 Ancillary Services: Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

1.2 Annual Transmission Costs: The total annual cost of the Transmission System for purposes of Network Integration Transmission Service shall be the amount specified in Attachment until amended by the Transmission Provider or modified by the Commission.

1.3 Application: A request by an Eligible Customer for transmission service pursuant to the provisions of the Tariff.

1.4 Commission: The Federal Energy Regulatory Commission.

1.5 Completed Application: An Application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

1.6 Control Area: An electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

(1) Match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(2) Maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(3) Maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

(4) Provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

1.7 Curtailment: A reduction in firm or non-firm transmission service in response to a transmission capacity shortage as a result of system reliability conditions.

1.8 Delivering Party: The entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

1.9 Designated Agent: Any entity that performs actions or functions on behalf of the Transmission Provider, an Eligible Customer, or the Transmission Customer required under the Tariff.

1.10 Direct Assignment Facilities: Facilities or portions of facilities that are constructed by the Transmission Provider for the sole use/benefit of a particular Transmission Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Commission approval.

1.11 Eligible Customer: (i) Any electric utility (including the Transmission Provider and any power marketer), Federal power marketing agency, or any person generating electric energy for sale for resale is an Eligible Customer under the Tariff. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Provider offer the unbundled transmission service, or pursuant to a voluntary offer of such service by the Transmission Provider. (ii) Any retail customer taking unbundled transmission service pursuant to a state requirement that the Transmission Provider offer the transmission service, or pursuant to a voluntary offer of such service by the Transmission Provider, is an Eligible Customer under the Tariff.

1.12 Facilities Study: An engineering study conducted by the Transmission Provider to determine the required modifications to the Transmission Provider's Transmission System, including the cost and scheduled completion date for such modifications, that will be required to provide the requested transmission service.

1.13 Firm Point-To-Point Transmission Service: Transmission Service under this Tariff that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Part II of this Tariff.

1.14 Good Utility Practice: Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

1.15 Interruption: A reduction in non-firm transmission service due to economic reasons pursuant to Section 14.7.

1.16 Load Ratio Share: Ratio of a Transmission Customer's Network Load to the Transmission Provider's total load computed in accordance with Sections 34.2 and 34.3 of the Network Integration Transmission Service under Part III the Tariff and calculated on a rolling twelve month basis.

1.17 Load Shedding: The systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations under Part III of the Tariff.

1.18 Long-Term Firm Point-To-Point Transmission Service: Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of one year or more.

1.19 Native Load Customers: The wholesale and retail power customers of the Transmission Provider on whose behalf the Transmission Provider, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Provider's system to meet the reliable electric needs of such customers.

1.20 Network Customer: An entity receiving transmission service pursuant to the terms of the Transmission Provider's Network Integration Transmission Service under Part III of the Tariff.

1.21 Network Integration Transmission Service: The transmission service provided under Part III of the Tariff.

1.22 Network Load: The load that a Network Customer designates for Network Integration Transmission Service under Part III of the Tariff. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Part II of the Tariff for any Point-To-Point Transmission Service that may be necessary for such non-designated load.

1.23 Network Operating Agreement: An executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Part III of the Tariff.

1.24 Network Operating Committee: A group made up of representatives from the Network Customer(s) and the Transmission Provider established to coordinate operating criteria and other technical considerations required for implementation of Network Integration Transmission Service under Part III of this Tariff.

1.25 Network Resource: Any designated generating resource owned, purchased or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

1.26 Network Upgrades: Modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users of such Transmission System.

1.27 Non-Firm Point-To-Point Transmission Service: Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Section 14.7 under Part II of this Tariff. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month. ***12467**

1.28 Open Access Same-Time Information System (OASIS): The information system and standards of conduct contained in Part 37 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

1.29 Part I: Tariff Definitions and Common Service Provisions contained in Sections 2 through 12.

1.30 Part II: Tariff Sections 13 through 27 pertaining to Point-To-Point Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.31 Part III: Tariff Sections 28 through 35 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.32 Parties: The Transmission Provider and the Transmission Customer receiving service under the Tariff.

1.33 Point(s) of Delivery: Point(s) on the Transmission Provider's Transmission System where capacity and energy transmitted by the Transmission Provider will be made available to the Receiving Party under Part II of the Tariff. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.34 Point(s) of Receipt: Point(s) of interconnection on the Transmission Provider's Transmission System where capacity and energy will be made available to the Transmission Provider by the Delivering Party under Part II of the Tariff. The Point(s) of Receipt shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.35 Point-To-Point Transmission Service: The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Part II of the Tariff.

1.36 Power Purchaser: The entity that is purchasing the capacity and energy to be transmitted under the Tariff.

1.37 Receiving Party: The entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

1.38 Regional Transmission Group (RTG): A voluntary organization of transmission owners, transmission users and other entities approved by the Commission to efficiently coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

1.39 Reserved Capacity: The maximum amount of capacity and energy that the Transmission Provider agrees to transmit for the Transmission Customer over the Transmission Provider's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II of the Tariff. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

1.40 Service Agreement: The initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the Transmission Provider for service under the Tariff.

1.41 Service Commencement Date: The date the Transmission Provider begins to provide service pursuant to the terms of an executed Service Agreement, or the date the Transmission Provider begins to provide service in accordance with Section 15.3 or Section 29.1 under the Tariff.

1.42 Short-Term Firm Point-To-Point Transmission Service: Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of less than one year.

1.43 System Impact Study: An assessment by the Transmission Provider of (i) the adequacy of the Transmission System to accommodate a request for either Firm Point-To-Point Transmission Service or Network Integration Transmission Service and (ii) whether any additional costs may be incurred in order to provide transmission service.

1.44 Third-Party Sale: Any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Network Load under the Network Integration Transmission Service.

1.45 Transmission Customer: Any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that the Transmission Provider file with the Commission, a proposed unexecuted Service Agreement to receive transmission service under Part II of the Tariff. This term is used in the Part I Common Service Provisions to include customers receiving transmission service under Part II and Part III of this Tariff.

1.46 Transmission Provider: The public utility (or its Designated Agent) that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides transmission service under the Tariff.

1.47 Transmission Provider's Monthly Transmission System Peak: The maximum firm usage of the Transmission Provider's Transmission System in a calendar month.

1.48 Transmission Service: Point-To-Point Transmission Service provided under Part II of the Tariff on a firm and non-firm basis.

1.49 Transmission System: The facilities owned, controlled or operated by the Transmission Provider that are used to provide transmission service under Part II and Part III of the Tariff.

2. Initial Allocation and Renewal Procedures

2.1 Initial Allocation of Available Transmission Capability: For purposes of determining whether existing capability on the Transmission Provider's Transmission System is adequate to accommodate a request for firm service under this Tariff, all Completed Applications for new firm transmission service received during the initial sixty (60) day period commencing with the effective date of the Tariff will be deemed to have been filed simultaneously. A lottery system conducted by an independent party shall be used to assign priorities for Completed Applications filed simultaneously. All Completed Applications for firm transmission service received after the initial sixty (60) day period shall be assigned a priority pursuant to Section 13.2.

2.2 Reservation Priority For Existing Firm Service Customers: Existing firm service customers (wholesale requirements and transmission-only, with a contract term of one-year or more), have the right to continue to take transmission service from the Transmission Provider when the contract expires, rolls over or is renewed. This transmission reservation priority is independent of whether the existing customer continues to purchase capacity and energy from the Transmission Provider or elects to purchase capacity and energy from another supplier. If at the end of the contract term, the Transmission Provider's Transmission System cannot accommodate all of the requests for transmission service the existing firm service customer must agree to accept a contract term at least equal to a competing request by any new Eligible Customer and to pay the current just and reasonable rate, as approved by the Commission, for such service. This transmission reservation priority for existing firm service customers is an ongoing right that may be exercised at the end of all firm contract terms of one-year or longer.

3. Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. The Transmission Provider is required to provide (or offer to arrange with the local Control Area operator as discussed below), and the Transmission Customer is required to purchase, the following Ancillary Services (i) Scheduling, System Control and Dispatch, and (ii) Reactive Supply and Voltage Control from Generation Sources.

The Transmission Provider is required to offer to provide (or offer to arrange with the local Control Area operator as discussed below) the following Ancillary Services only to the Transmission Customer serving load within the Transmission Provider's Control Area (i) Regulation and Frequency Response, (ii) Energy Imbalance, (iii) Operating Reserve—Spinning, and (iv) Operating Reserve—Supplemental. The Transmission Customer serving load within the Transmission Provider's Control Area is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply. The Transmission Customer may not decline the Transmission Provider's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from the Transmission Provider.

If the Transmission Provider is a public utility providing transmission service but is not a Control Area operator, it may be unable to provide some or all of the Ancillary Services. In this case, the Transmission Provider can fulfill its obligation to provide Ancillary Services by acting as the Transmission Customer's agent to secure these Ancillary Services from the Control Area operator. The Transmission Customer ***12468** may elect to (i) have the Transmission Provider act as its agent, (ii) secure the Ancillary Services directly from the Control Area operator, or (iii) secure the Ancillary Services (discussed in Schedules 3, 4, 5 and 6) from a third party or by self-supply when technically feasible.

The Transmission Provider shall specify the rate treatment and all related terms and conditions in the event of an unauthorized use of Ancillary Services by the Transmission Customer.

The specific Ancillary Services, prices and/or compensation methods are described on the Schedules that are attached to and made a part of the Tariff. Three principal requirements apply to discounts for Ancillary Services provided by the Transmission Provider in conjunction with its provision of transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers on the Transmission Provider's system. Sections 3.1 through 3.6 below list the six Ancillary Services.

3.1 Scheduling, System Control and Dispatch Service: The rates and/or methodology are described in Schedule 1.

3.2 Reactive Supply and Voltage Control from Generation Sources Service: The rates and/or methodology are described in Schedule 2.

3.3 Regulation and Frequency Response Service: Where applicable the rates and/or methodology are described in Schedule 3.

3.4 Energy Imbalance Service: Where applicable the rates and/or methodology are described in Schedule 4.

3.5 Operating Reserve—Spinning Reserve Service: Where applicable the rates and/or methodology are described in Schedule 5.

3.6 Operating Reserve—Supplemental Reserve Service: Where applicable the rates and/or methodology are described in Schedule 6.

4 Open Access Same-Time Information System (OASIS)

Terms and conditions regarding Open Access Same-Time Information System and standards of conduct are set forth in 18 CFR §37 of the Commission's regulations (Open Access Same-Time Information System and Standards of Conduct for Public Utilities). In the event available transmission capability as posted on the OASIS is insufficient to accommodate a request for firm transmission service, additional studies may be required as provided by this Tariff pursuant to Sections 19 and 32.

5 Local Furnishing Bonds

5.1 Transmission Providers That Own Facilities Financed by Local Furnishing Bonds: This provision is applicable only to Transmission Providers that have financed facilities for the local furnishing of electric energy with tax-exempt bonds, as described in Section 142(f) of the Internal Revenue Code ("local furnishing bonds"). Notwithstanding any other provision of this Tariff, the Transmission Provider shall not be required to provide transmission service to any Eligible Customer pursuant to this Tariff if the provision of such transmission service would jeopardize the tax-exempt status of any local furnishing bond(s) used to finance the Transmission Provider's facilities that would be used in providing such transmission service.

5.2 Alternative Procedures for Requesting Transmission Service:

(i) If the Transmission Provider determines that the provision of transmission service requested by an Eligible Customer would jeopardize the tax-exempt status of any local furnishing bond(s) used to finance its facilities that would be used in providing such transmission service, it shall advise the Eligible Customer within thirty (30) days of receipt of the Completed Application.

(ii) If the Eligible Customer thereafter renews its request for the same transmission service referred to in (i) by tendering an application under Section 211 of the Federal Power Act, the Transmission Provider, within ten (10) days of receiving a copy of the Section 211 application, will waive its rights to a request for service under Section 213(a) of the Federal Power Act and to the issuance of a proposed order under Section 212(c) of the Federal Power Act. The Commission, upon receipt of the Transmission Provider's waiver of its rights to a request for service under Section 213(a) of the Federal Power Act and to the issuance of a proposed order under Section 212(c) of the Federal Power Act, shall issue an order under Section 211 of the Federal Power Act. Upon issuance of the order under Section 211 of the Federal Power Act, the Transmission Provider shall be required to provide the requested transmission service in accordance with the terms and conditions of this Tariff.

6 Reciprocity

A Transmission Customer receiving transmission service under this Tariff agrees to provide comparable transmission service that it is capable of providing to the Transmission Provider on similar terms and conditions over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer and over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer's corporate affiliates. A Transmission Customer that is a member of a power pool or Regional Transmission Group also agrees to provide comparable transmission service to the members of such power pool and Regional Transmission Group on similar terms and conditions over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer and over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer's corporate affiliates.

This reciprocity requirement applies not only to the Transmission Customer that obtains transmission service under the Tariff, but also to all parties to a transaction that involves the use of transmission service under the Tariff, including the power seller, buyer and any intermediary, such as a power marketer. This reciprocity requirement also applies to any Eligible Customer that owns, controls or operates transmission facilities that uses an intermediary, such as a power marketer, to request transmission service under the Tariff. If the Transmission Customer does not own, control or operate transmission facilities, it must include in its Application a sworn statement of one of its duly authorized officers or other representatives that the purpose of its Application is not to assist an Eligible Customer to avoid the requirements of this provision.

7 Billing and Payment

7.1 Billing Procedure: Within a reasonable time after the first day of each month, the Transmission Provider shall submit an invoice to the Transmission Customer for the charges for all services furnished under the Tariff during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to the Transmission Provider, or by wire transfer to a bank named by the Transmission Provider.

7.2 Interest on Unpaid Balances: Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. §35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by the Transmission Provider.

7.3 Customer Default: In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to the Transmission Provider on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after the Transmission Provider notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, the Transmission Provider may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between the Transmission Provider and the Transmission Customer, the Transmission Provider will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then the Transmission Provider may provide notice to the Transmission Customer of its intention to suspend service in sixty ***12469** (60) days, in accordance with Commission policy.

8 Accounting for the Transmission Provider's Use of the Tariff

The Transmission Provider shall record the following amounts, as outlined below.

8.1 Transmission Revenues: Include in a separate operating revenue account or subaccount the revenues it receives from Transmission Service when making Third-Party Sales under Part II of the Tariff.

8.2 Study Costs and Revenues: Include in a separate transmission operating expense account or subaccount, costs properly chargeable to expense that are incurred to perform any System Impact Studies or Facilities Studies which the Transmission Provider conducts to determine if it must construct new transmission facilities or upgrades necessary for its own uses, including making Third-Party Sales under the Tariff; and include in a separate operating revenue account or subaccount the revenues received for System Impact Studies or Facilities Studies performed when such amounts are separately stated and identified in the Transmission Customer's billing under the Tariff.

9 Regulatory Filings

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the right of the Transmission Provider to unilaterally make application to the Commission for a change in rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the ability of any Party receiving service under the Tariff to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

10 Force Majeure and Indemnification

10.1 Force Majeure: An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing. Neither the Transmission Provider nor the Transmission Customer will be considered in default as to any obligation under this Tariff if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Tariff is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Tariff.

10.2 Indemnification: The Transmission Customer shall at all times indemnify, defend, and save the Transmission Provider harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the Transmission Provider's performance of its obligations under this Tariff on behalf of the Transmission Customer, except in cases of negligence or intentional wrongdoing by the Transmission Provider.

11 Creditworthiness

For the purpose of determining the ability of the Transmission Customer to meet its obligations related to service hereunder, the Transmission Provider may require reasonable credit review procedures. This review shall be made in accordance with standard commercial practices. In addition, the Transmission Provider may require the Transmission Customer to provide and maintain in effect during the term of the Service Agreement, an unconditional and irrevocable letter of credit as security to meet its responsibilities and obligations under the Tariff, or an alternative form of security proposed by the Transmission Customer and acceptable to the Transmission Provider and consistent with commercial practices established by the Uniform Commercial Code that protects the Transmission Provider against the risk of non-payment.

12 Dispute Resolution Procedures

12.1 Internal Dispute Resolution Procedures: Any dispute between a Transmission Customer and the Transmission Provider involving transmission service under the Tariff (excluding applications for rate changes or other changes to the Tariff, or to any Service Agreement entered into under the Tariff, which shall be presented directly to the Commission for resolution) shall be referred to a designated senior representative of the Transmission Provider and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days [or such other period as the Parties may agree upon] by mutual agreement, such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below.

12.2 External Arbitration Procedures: Any arbitration initiated under the Tariff shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable Commission regulations or Regional Transmission Group rules.

12.3 Arbitration Decisions: Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of the Tariff and any Service Agreement entered into under the Tariff and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act and/or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with the Commission if it affects jurisdictional rates, terms and conditions of service or facilities.

12.4 Costs: Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

(A) The cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or

(B) One half the cost of the single arbitrator jointly chosen by the Parties.

12.5 Rights Under The Federal Power Act: Nothing in this section shall restrict the rights of any party to file a Complaint with the Commission under relevant provisions of the Federal Power Act.

II. Point-to-Point Transmission Service

Preamble

The Transmission Provider will provide Firm and Non-Firm Point-To-Point Transmission Service pursuant to the applicable terms and conditions of this Tariff. Point-To-Point Transmission Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transmission of such capacity and energy to designated Point(s) of Delivery.

13 Nature of Firm Point-To-Point Transmission Service

13.1 Term: The minimum term of Firm Point-To-Point Transmission Service shall be one day and the maximum term shall be specified in the Service Agreement.

13.2 Reservation Priority: Long-Term Firm Point-To-Point Transmission Service shall be available on a first-come, first-served basis i.e., in the chronological sequence in which each Transmission Customer has reserved service. Reservations for Short-Term Firm Point-To-Point Transmission Service will be conditional based upon the length of the requested transaction. If the Transmission System becomes oversubscribed, requests for longer term service may preempt requests for shorter term service up to the following ***12470** deadlines: one day before the commencement of daily service, one week before the commencement of weekly service, and one month before the commencement of monthly service. Before the conditional reservation deadline, if available transmission capability is insufficient to satisfy all Applications, an Eligible Customer with a reservation for shorter term service has the right of first refusal to match any longer term reservation before losing its reservation priority. A longer term competing request for Short-Term Firm Point-To-Point Transmission Service will be granted if the Eligible Customer with the right of first refusal does not agree to match the competing request within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in section 13.8) from being notified by the Transmission Provider of a longer-term competing request for Short-Term Firm Point-To-Point Transmission Service. After the conditional reservation deadline, service will commence pursuant to the terms of Part II of the Tariff. Firm Point-To-Point Transmission Service will always have a reservation priority over Non-Firm Point-To-Point Transmission Service under the Tariff. All Long-Term Firm Point-To-Point Transmission Service will have equal reservation priority with Native Load Customers and Network Customers. Reservation priorities for existing firm service customers are provided in Section 2.2.

13.3 Use of Firm Transmission Service by the Transmission Provider: The Transmission Provider will be subject to the rates, terms and conditions of Part II of the Tariff when making Third-Party Sales under (i) agreements executed on or after [insert date sixty (60) days after publication in Federal Register] or (ii) agreements executed prior to the aforementioned date that the Commission requires to be unbundled, by the date specified by the Commission. The Transmission Provider will maintain separate accounting, pursuant to Section 8 , for any use of the Point-To-Point Transmission Service to make Third-Party Sales.

13.4 Service Agreements: The Transmission Provider shall offer a standard form Firm Point-To-Point Transmission Service Agreement (Attachment A) to an Eligible Customer when it submits a Completed Application for Long-Term Firm Point-To-Point Transmission Service. The Transmission Provider shall offer a standard form Firm Point-To-Point Transmission Service Agreement (Attachment A) to an Eligible Customer when it first submits a Completed Application for Short-Term Firm Point-To-Point Transmission Service pursuant to the Tariff. Executed Service Agreements that contain the information required under the Tariff shall be filed with the Commission in compliance with applicable Commission regulations.

13.5 Transmission Customer Obligations for Facility Additions or Redispatch Costs: In cases where the Transmission Provider determines that the Transmission System is not capable of providing Firm Point-To-Point Transmission Service without (1) degrading or impairing the reliability of service to Native Load Customers, Network Customers and other Transmission Customers taking Firm Point-To-Point Transmission Service, or (2) interfering with the Transmission Provider's ability to meet prior firm contractual commitments to others, the Transmission Provider will be obligated to expand or upgrade its Transmission System pursuant to the terms of Section 15.4. The Transmission Customer must agree to compensate the Transmission Provider for any necessary transmission facility additions pursuant to the terms of Section 27. To the extent the Transmission Provider can relieve any system constraint more economically by redispatching the Transmission Provider's resources than through constructing Network Upgrades, it shall do so, provided that the Eligible Customer agrees to compensate the Transmission Provider pursuant to the terms of Section 27 . Any redispatch, Network Upgrade or Direct Assignment Facilities costs to be charged to the Transmission Customer on an incremental basis under the Tariff will be specified in the Service Agreement prior to initiating service.

13.6 Curtailment of Firm Transmission Service: In the event that a Curtailment on the Transmission Provider's Transmission System, or a portion thereof, is required to maintain reliable operation of such system, Curtailments will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint. If multiple transactions require Curtailment, to the extent practicable and consistent with Good Utility Practice, the Transmission Provider will curtail service to Network Customers and Transmission Customers taking Firm Point-To-Point Transmission Service on a basis comparable to the curtailment of service to the Transmission Provider's Native Load Customers. All Curtailments will be made on a non-discriminatory basis, however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service. When the Transmission Provider determines that an electrical emergency exists on its Transmission System and implements emergency procedures to Curtail Firm Transmission Service, the Transmission Customer shall make the required reductions upon request of the Transmission Provider. However, the Transmission Provider reserves the right to Curtail, in whole or in part, any Firm Transmission Service provided under the Tariff when, in the Transmission Provider's sole discretion, an emergency or other unforeseen condition impairs or degrades the reliability of its Transmission System. The Transmission Provider will notify all affected Transmission Customers in a timely manner of any scheduled Curtailments.

13.7 Classification of Firm Transmission Service:

(a) The Transmission Customer taking Firm Point-To-Point Transmission Service may (1) change its Receipt and Delivery Points to obtain service on a non-firm basis consistent with the terms of Section 22.1 or (2) request a modification of the Points of Receipt or Delivery on a firm basis pursuant to the terms of Section 22.2.

(b) The Transmission Customer may purchase transmission service to make sales of capacity and energy from multiple generating units that are on the Transmission Provider's Transmission System. For such a purchase of transmission service, the resources will be designated as multiple Points of Receipt, unless the multiple generating units are at the same generating plant in which case the units would be treated as a single Point of Receipt.

(c) The Transmission Provider shall provide firm deliveries of capacity and energy from the Point(s) of Receipt to the Point(s) of Delivery. Each Point of Receipt at which firm transmission capacity is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for Long-Term Firm Transmission Service along with a corresponding capacity reservation associated with each Point of Receipt. Points of Receipt and corresponding capacity reservations shall be as mutually agreed upon by the Parties for Short-Term Firm Transmission. Each Point of Delivery at which firm transmission capacity is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for Long-Term Firm Transmission Service along with a corresponding capacity reservation associated with each Point of Delivery. Points of Delivery and corresponding capacity reservations shall be as mutually agreed upon by the Parties for Short-Term Firm Transmission. The greater of either (1) the sum of the capacity reservations at the Point(s) of Receipt, or (2) the sum of the capacity reservations at the Point(s) of Delivery shall be the Transmission Customer's Reserved Capacity. The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule 7. The Transmission Customer may not exceed its firm capacity reserved at each Point of Receipt and each Point of Delivery except as otherwise specified in Section 22. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by the Transmission Provider) exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery.

13.8 Scheduling of Firm Point-To-Point Transmission Service: Schedules for the Transmission Customer's Firm Point-To-Point Transmission Service must be submitted to the Transmission Provider no later than 10:00 a.m. [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] of the day prior to commencement of such service. Schedules submitted after 10:00 a.m. will be accommodated, if practicable. Hour-to-hour schedules of any capacity and energy that is to be delivered must be stated in increments of 1,000 kW per hour [or a reasonable increment that is generally accepted in the region and is consistently adhered to by the Transmission Provider]. Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their service requests at a common point of receipt into units of 1,000 kW per hour for scheduling and billing purposes. Scheduling changes will be ***12471** permitted up to twenty (20) minutes [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] before the start of the next clock hour provided that the Delivering Party and Receiving Party also agree to the schedule modification. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

14 Nature of Non-Firm Point-To-Point Transmission Service

14.1 Term: Non-Firm Point-To-Point Transmission Service will be available for periods ranging from one (1) hour to one (1) month. However, a Purchaser of Non-Firm Point-To-Point Transmission Service will be entitled to reserve a sequential term of service (such as a sequential monthly term without having to wait for the initial term to expire before requesting another monthly term) so that the total time period for which the reservation applies is greater than one month, subject to the requirements of Section 18.3.

14.2 Reservation Priority: Non-Firm Point-To-Point Transmission Service shall be available from transmission capability in excess of that needed for reliable service to Native Load Customers, Network Customers and other Transmission Customers taking Long-Term and Short-Term Firm Point-To-Point Transmission Service. A higher priority will be assigned to reservations with a longer duration of service. In the event the Transmission System is constrained, competing requests of equal duration will be prioritized based on the highest price offered by the Eligible Customer for the Transmission Service. Eligible Customers that have already reserved shorter term service have the right of first refusal to match any longer term reservation before being preempted. A longer term competing request for Non-Firm Point-To-Point Transmission Service will be granted if the Eligible Customer with the right of first refusal does not agree to match the competing request: (a) immediately for hourly Non-Firm Point-To-Point Transmission Service after notification by the Transmission Provider; and, (b) within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in section 14.6) for Non-Firm Point-To-Point Transmission Service other than hourly transactions after notification by the Transmission Provider. Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service. Non-Firm Point-To-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have the lowest reservation priority under the Tariff.

14.3 Use of Non-Firm Point-To-Point Transmission Service by the Transmission Provider: The Transmission Provider will be subject to the rates, terms and conditions of Part II of the Tariff when making Third-Party Sales under (i) agreements executed on or after [insert date sixty (60) days after publication in Federal Register] or (ii) agreements executed prior to the aforementioned date that the Commission requires to be unbundled, by the date specified by the Commission. The Transmission Provider will maintain separate accounting, pursuant to Section 8 , for any use of Non-Firm Point-To-Point Transmission Service to make Third-Party Sales.

14.4 Service Agreements: The Transmission Provider shall offer a standard form Non-Firm Point-To-Point Transmission Service Agreement (Attachment B) to an Eligible Customer when it first submits a Completed Application for Non-Firm Point-To-Point Transmission Service pursuant to the Tariff. Executed Service Agreements that contain the information required under the Tariff shall be filed with the Commission in compliance with applicable Commission regulations.

14.5 Classification of Non-Firm Point-To-Point Transmission Service: Non-Firm Point-To-Point Transmission Service shall be offered under terms and conditions contained in Part II of the Tariff. The Transmission Provider undertakes no obligation under the Tariff to plan its Transmission System in order to have sufficient capacity for Non-Firm Point-To-Point Transmission Service. Parties requesting Non-Firm Point-To-Point Transmission Service for the transmission of firm power do so with the full realization that such service is subject to availability and to Curtailment or Interruption under the terms of the Tariff. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by the Transmission Provider) exceeds its non-firm capacity reservation. Non-Firm Point-To-Point Transmission Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and energy on a daily, weekly or monthly basis, but not to exceed one month's reservation for any one Application, under Schedule 8.

14.6 Scheduling of Non-Firm Point-To-Point Transmission Service: Schedules for Non-Firm Point-To-Point Transmission Service must be submitted to the Transmission Provider no later than 2:00 p.m. [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] of the day prior to commencement of such service. Schedules submitted after 2:00 p.m. will be accommodated, if practicable. Hour-to-hour schedules of energy that is to be delivered must be stated in increments of 1,000 kW per hour [or a reasonable increment that is generally accepted in the region and is consistently adhered to by the Transmission Provider]. Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their schedules at a common Point of Receipt into units of 1,000 kW per hour. Scheduling changes will be permitted up to twenty (20) minutes [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] before the start of the next clock hour provided that the Delivering Party and Receiving Party also agree to the schedule modification. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

14.7 Curtailment or Interruption of Service: The Transmission Provider reserves the right to Curtail, in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for reliability reasons when, an emergency or other unforeseen condition threatens to impair or degrade the reliability of its Transmission System. The Transmission Provider reserves the right to Interrupt, in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for economic reasons in order to accommodate (1) a request for Firm Transmission Service, (2) a request for Non-Firm Point-To-Point Transmission Service of greater duration, (3) a request for Non-Firm Point-To-Point Transmission Service of equal duration with a higher price, or (4) transmission service for Network Customers from non-designated resources. The Transmission Provider also will discontinue or reduce service to the Transmission Customer to the extent that deliveries for transmission are discontinued or reduced at the Point(s) of Receipt. Where required, Curtailments or Interruptions will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint, however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service. If multiple transactions require Curtailment or Interruption, to the extent practicable and consistent with Good Utility Practice, Curtailments or Interruptions will be made to transactions of the shortest term (e.g., hourly non-firm transactions will be Curtailed or Interrupted before daily non-firm transactions and daily non-firm transactions will be Curtailed or Interrupted before weekly non-firm transactions). Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under the Tariff. Non-Firm Point-To-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have a lower priority than any Non-Firm ***12472** Point-To-Point Transmission Service under the Tariff. The Transmission Provider will provide advance notice of Curtailment or Interruption where such notice can be provided consistent with Good Utility Practice.

15 Service Availability

15.1 General Conditions: The Transmission Provider will provide Firm and Non-Firm Point-To-Point Transmission Service over, on or across its Transmission System to any Transmission Customer that has met the requirements of Section 16.

15.2 Determination of Available Transmission Capability: A description of the Transmission Provider's specific methodology for assessing available transmission capability posted on the Transmission Provider's OASIS (Section) is contained in Attachment of the Tariff. In the event sufficient transmission capability may not exist to accommodate a service request, the Transmission Provider will respond by performing a System Impact Study.

15.3 Initiating Service in the Absence of an Executed Service Agreement: If the Transmission Provider and the Transmission Customer requesting Firm or Non-Firm Point-To-Point Transmission Service cannot agree on all the terms and conditions of the Point-To-Point Service Agreement, the Transmission Provider shall file with the Commission, within thirty (30) days after the date the Transmission Customer provides written notification directing the Transmission Provider to file, an unexecuted Point-To-Point Service Agreement containing terms and conditions deemed appropriate by the Transmission Provider for such requested Transmission Service. The Transmission Provider shall commence providing Transmission Service subject to the Transmission Customer agreeing to (i) compensate the Transmission Provider at whatever rate the Commission ultimately determines to be just and reasonable, and (ii) comply with the terms and conditions of the Tariff including posting appropriate security deposits in accordance with the terms of Section 17.3.

15.4 Obligation to Provide Transmission Service that Requires Expansion or Modification of the Transmission System: If the Transmission Provider determines that it cannot accommodate a Completed Application for Firm Point-To-Point Transmission

Service because of insufficient capability on its Transmission System, the Transmission Provider will use due diligence to expand or modify its Transmission System to provide the requested Firm Transmission Service, provided the Transmission Customer agrees to compensate the Transmission Provider for such costs pursuant to the terms of Section 27. The Transmission Provider will conform to Good Utility Practice in determining the need for new facilities and in the design and construction of such facilities. The obligation applies only to those facilities that the Transmission Provider has the right to expand or modify.

15.5 Deferral of Service: The Transmission Provider may defer providing service until it completes construction of new transmission facilities or upgrades needed to provide Firm Point-To-Point Transmission Service whenever the Transmission Provider determines that providing the requested service would, without such new facilities or upgrades, impair or degrade reliability to any existing firm services.

15.6 Other Transmission Service Schedules: Eligible Customers receiving transmission service under other agreements on file with the Commission may continue to receive transmission service under those agreements until such time as those agreements may be modified by the Commission.

15.7 Real Power Losses: Real Power Losses are associated with all transmission service. The Transmission Provider is not obligated to provide Real Power Losses. The Transmission Customer is responsible for replacing losses associated with all transmission service as calculated by the Transmission Provider. The applicable Real Power Loss factors are as follows: [To be completed by the Transmission Provider].

16 Transmission Customer Responsibilities

16.1 Conditions Required of Transmission Customers: Point-To-Point Transmission Service shall be provided by the Transmission Provider only if the following conditions are satisfied by the Transmission Customer:

a. The Transmission Customer has pending a Completed Application for service;

b. The Transmission Customer meets the creditworthiness criteria set forth in Section 11;

c. The Transmission Customer will have arrangements in place for any other transmission service necessary to effect the delivery from the generating source to the Transmission Provider prior to the time service under Part II of the Tariff commences;

d. The Transmission Customer agrees to pay for any facilities constructed and chargeable to such Transmission Customer under Part II of the Tariff, whether or not the Transmission Customer takes service for the full term of its reservation; and

e. The Transmission Customer has executed a Point-To-Point Service Agreement or has agreed to receive service pursuant to Section 15.3.

16.2 Transmission Customer Responsibility for Third-Party Arrangements: Any scheduling arrangements that may be required by other electric systems shall be the responsibility of the Transmission Customer requesting service. The Transmission Customer shall provide, unless waived by the Transmission Provider, notification to the Transmission Provider identifying such systems and authorizing them to schedule the capacity and energy to be transmitted by the Transmission Provider pursuant to Part II of the Tariff on behalf of the Receiving Party at the Point of Delivery or the Delivering Party at the Point of Receipt. However, the Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in making such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

17 Procedures for Arranging Firm Point-To-Point Transmission Service