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Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities; Final Rule

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket No. RM04–7–001; Order No. 697–A]

Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities

Issued April 21, 2008.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Order on Rehearing and Clarification.

SUMMARY: In this order on rehearing, the Commission affirms its basic determinations in Order No. 697, and grants rehearing and clarification regarding certain revisions to its regulations and to the standards for obtaining and retaining market-based rate authority for sales of energy, capacity and ancillary services to ensure that such sales are just and reasonable. The Commission also clarifies several aspects of the implementation process adopted in Order No. 697.

DATES: Effective Date: This rule will become effective June 6, 2008.

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SUPPLEMENTARY INFORMATION:

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Before Commissioners: Joseph T. Kelliher, Chairman; Suedeen G. Kelly, Marc Spitzer, Philip D. Moeller, and Jon Wellinghoff.

I. Introduction

1. On June 21, 2007, the Federal Energy Regulatory Commission (Commission) issued Order No. 697,[1] codifying and, in certain respects, revising its standards for obtaining and retaining market-based rates for public utilities. In order to accomplish this, as well as streamline the administration of the market-based rate program, the Commission modified its regulations at 18 CFR part 35, subpart H, governing market-based rate authorization. The Commission explained that there are three major aspects of its market-based regulatory regime: (1) Market power analyses of sellers and associated conditions and filing requirements; (2) market rules imposed on sellers that participate in Regional Transmission Organization (RTO) and Independent System Operator (ISO) organized markets; and (3) ongoing oversight and enforcement activities. The Final Rule focused on the first of the three features to ensure that market-based rates charged by public utilities are just and reasonable. Order No. 697 became effective on September 18, 2007.

2. On December 14, 2007, the Commission issued an order clarifying four aspects of Order No. 697.[2] Specifically, that order addressed: (1) The effective date for compliance with the requirements of Order No. 697; (2) which entities are required to file updated market power analyses for the Commission's regional review; (3) the data required for the horizontal market power analyses; and (4) what constitutes ''seller-specific terms and conditions'' that sellers may list in their market-based rate tariffs in addition to the standard provisions listed in Appendix C to Order No. 697. The Commission also extended the deadline for sellers to file the first set of regional triennial studies that were directed in Order No. 697 from December 2007 to 30 days after the date of issuance of the Clarification Order.

3. In this order, the Commission responds to a number of requests for rehearing and clarification of Order No. 697. In most respects, the Commission reaffirms its determinations made in Order No. 697 and denies rehearing of these issues. With respect to several issues, however, the Commission grants rehearing or provides clarification.

4. For example, the Commission affirms in large part the determinations made in Order No. 697 concerning the horizontal market power analysis, including the use of the 20 percent threshold for the indicative wholesale market share screen and the Delivered Price Test (DPT), the use of a 2,500 Hirschman-Herfindahl Index (HHI) threshold for the DPT analysis, and the use of the average peak native load as the native load proxy for the indicative wholesale market share screen and DPT analysis. The Commission also affirms its decision to use a balancing authority area or the RTO/ISO region as the default relevant geographic market. Similarly, the Commission affirms the decision that, where the Commission has made a specific finding that there is a submarket within an RTO/ISO, that submarket should be considered the default relevant geographic market. However, the Commission grants rehearing concerning the finding that Northern PSEG is a submarket within PJM. On reconsideration, we conclude that we erred in relying on a finding of a submarket in a particular proceeding that was subsequently vacated on procedural grounds.

5. In response to requests for clarification concerning existing mitigation in RTO/ISOs, the Commission adopts a rebuttable presumption that the existing Commission-approved RTO/ISO mitigation is sufficient to address market power concerns in the RTO/ISO market, including mitigation applicable to RTO/ISO submarkets. However, intervenors may challenge that presumption. Depending on the nature of the evidence submitted by an intervenor, the Commission will consider whether to institute a separate section 206 proceeding to investigate whether the existing RTO/ISO mitigation continues to be just and reasonable.

6. While the Commission affirms its determination to continue the use of historical data and a ''snapshot in time approach,'' the Commission will consider sensitivity studies, on a case-by-case basis, that present clear and compelling evidence that certain changes in a market should be taken into account as part of the market power analysis in a particular case.

7. With regard to simultaneous transmission import limit (SIL) studies, the Commission clarifies that the use of simultaneous total transfer capability (TTC) in the SIL study must properly account for all firm transmission reservations, transmission reliability margin, and capacity benefit margin.

8. The Commission affirms its determinations concerning the vertical market power analysis and clarifies that sellers are not required to report on financial transmission rights as part of the vertical market power analysis.

9. The Commission codifies in the regulations at 18 CFR 35.36 a definition of ''affiliate'' for purposes of Order No. 697 based on the definition adopted in the Affiliate Transactions Final Rule.[3] In addition, the Commission reiterates in this order a number of clarifications that it made in the Affiliate Transactions Final Rule regarding the term ''captive customers,'' the purpose of the definition, and its focus on ''cost-based regulation.'' Among other things, the Commission notes that if a state regulatory authority in a retail choice state does not believe that retail customers are sufficiently protected and that our affiliate restrictions should apply to the local franchised public utility, it may ask the Commission to deem its retail customers to be captive customers for purposes of applying the affiliate restrictions.

10. The Commission clarifies that the new affiliate restriction regulations promulgated in Order No. 697 supersede codes of conduct approved by the Commission prior to the effective date of Order No. 697. The Commission also provides a number of clarifications concerning employees who are not subject to the independent functioning requirement. Further, the Commission grants rehearing regarding the adoption of a two-way information sharing restriction in 18 CFR 35.39(d), finding, among other things, that a one-way information sharing restriction adequately protects captive customers.

11. The Commission for the most part affirms its determinations concerning mitigation, including retaining the Commission's default mitigation and declining to impose a generic ''must offer'' requirement. The Commission clarifies that it has not prejudged the types of specific situations in which it might impose a ''must offer'' requirement on a particular seller. In response to rehearing requests concerning the Commission's mitigation of long-term transactions based on the result of a failure of a short-term indicative screen, the Commission is modifying its policy with respect to

[1] *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities,* Order No. 697, 72 FR 39,904 (Jul. 20, 2007), FERC Stats. & Regs. ¶ 31,252 (2007) (Final Rule).

[2] *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities,* 121 FERC ¶ 61,260 (2007) (*Clarification Order*).

[3] *Cross-Subsidization Restrictions on Affiliate Transaction,* Order No. 707, 73 FR 11013 (Feb. 29, 2008), FERC Stats. & Regs. ¶ 31,264 (Feb. 21, 2008) (Affiliate Transactions Final Rule).

mitigation of long-term transactions (one year or more in duration). In this regard, the Commission will allow a mitigated seller to demonstrate on a case-by-case basis that it does not have market power with respect to a specific long-term contract.

12. Concerning the tariff provision adopted in the Final Rule for mitigated sellers that want to make market-based rate sales at the metered boundary between a balancing authority area in which the seller was found, or presumed, to have market power and a balancing authority area in which the seller has market-based rate authority, after considering comments raised regarding the difficulty of determining and documenting whether the power sold is intended to serve load in the balancing authority area in which the seller has market power, the Commission is revising the tariff language to eliminate the intent element.

13. The Commission affirms, among other things, its determination in Order No. 697 to create a category of market-based rate sellers (Category 1 sellers) that are not required to automatically submit updated market power analyses, as well as its decision to adopt a regional filing process for updated market power analyses. In response to concerns raised regarding the potential for Category 1 sellers to exercise market power in load pockets or other transmission-constrained areas, we explain that we are modifying our approach. To the extent that a Commission-identified submarket is under analysis (relevant submarket), if the Commission determines based on analysis of indicative screens filed by other sellers that there may be potential market power concerns with respect to any Category 1 sellers in the relevant submarket, the Commission will, if appropriate, require an updated market power analysis to be filed by such Category 1 sellers and allow other parties to comment. In this regard, the Commission would be exercising its right to require an updated market power analysis at any time.

14. The Commission also provides clarifications regarding other aspects of the Final Rule, including addressing questions that have arisen concerning the implementation process adopted in Order No. 697 and providing clarifications concerning the change in status reporting requirement.

15. Finally, the Commission rejects as without merit arguments raised by petitioners challenging the Commission's authority to adopt market-based rates and alleging that the market-based rate program fails to comply with the requirements of the FPA.

II. Discussion

A. Horizontal Market Power

1. Whether To Retain the Indicative Screens

Final Rule

16. In Order No. 697, the Commission adopted, with some modifications, two indicative market power screens (the uncommitted market share screen and the uncommitted pivotal supplier screen) to determine whether sellers may have market power and should be further examined. The Commission explained that sellers that fail either screen would rebuttably be presumed to have market power, but they would have an opportunity to present evidence (through the submission of a Delivered Price Test (DPT) analysis) demonstrating they do not have market power. The Commission concluded that, although some sellers disagree with the use of two screens or find flaws in them, the conservative approach of using two screens together would allow the Commission to more readily identify potential market power by measuring market power at both peak and off-peak times and both unilaterally and in coordinated interaction with other sellers. The Commission explained that a conservative approach at the indicative screen stage of the proceeding is warranted because, if a seller passes both of the indicative screens, there is a rebuttable presumption that it does not possess horizontal market power.[4] In conclusion, the approach represented an appropriate balance between the need to protect against market power and the desire not to place unnecessary filing burdens on utilities.[5]

17. The wholesale market share screen measures for each of the four seasons whether a seller has a dominant position in the market based on the number of megawatts of uncommitted capacity owned or controlled by the seller as compared to the uncommitted capacity of the entire relevant market. When calculating uncommitted capacity, a seller adds the total nameplate or seasonal capacity of generation owned or controlled through contract plus long-term firm purchases and deducts operating reserves, native load commitments, and long-term firm sales.[6]

18. The pivotal supplier analysis evaluates the potential of a seller to exercise market power based on uncommitted capacity at the time of the relevant market's annual peak demand, focusing on the seller's ability to exercise market power unilaterally. It examines whether the market demand can be met absent the seller during peak times; a seller is determined to be pivotal if demand cannot be met without some contribution of supply by the seller or its affiliates. For purposes of identifying the wholesale market, the Commission explained that the ''proxy for the wholesale load is the annual peak load (needle peak) less the proxy for native load obligation (*i.e.*, the average of the daily native load peaks during the month in which the annual peak load day occurs).'' [7]

19. The Commission chose not to adopt suggestions to alter the indicative screens in order to incorporate a contestable load analysis, as proposed by some commenters. Such an analysis would consider the amount of excess market supply available to serve the amount of wholesale demand seeking supply at a particular moment in time.[8] The Commission reasoned that such an analysis is essentially a variant on the pivotal supplier screen with differences in the calculation of wholesale load and the test thresholds since it addresses whether suppliers other than the seller can meet the demand in the relevant market. The Commission concluded that incorporating such an analysis would not improve its ability to establish a presumption of whether a seller has market power, and ''without the market share indicative screen, the Commission would have insufficient information because there would be no analysis of a seller's size relative to the other sellers in the market, and no information on the seller's market power during off-peak periods.'' [9] Additionally, the

[4] Order No. 697 at P 62.

[5] *Id.* P 33, 35.

[6] Order No. 697 states that uncommitted capacity is determined by adding the total nameplate capacity of generation owned or controlled through contract and firm purchases, less operating reserves, native load commitments and long-term firm sales. Order No. 697 at P 38. Order No. 697 further states that uncommitted capacity from a seller's remote generation (generation located in an adjoining balancing authority area) should be included in the seller's total uncommitted capacity amounts. *Id.* However, one of the standard screen formats included at Appendix A to Order No. 697 does not capture these details. Part I—Pivotal Supplier Analysis, inadvertently does not include Row H (imported power) and Row M (average daily Peak Native Load in Peak month, a proxy for native load commitment) in calculating Row K (total uncommitted supply). We thus correct this error in the Revised Appendix A to include the missing variables of the equation.

[7] *Id.* P 41.

[8] *See Id.* P 49. Generally, advocates of the contestable load analysis believe that, if available non-applicant supply is at least twice the contestable load, that is sufficient to make a finding that the market is competitive.

[9] *Id.* P 66.

Commission noted that the contestable load analysis fails to consider the relative price of the competing supplies and thus whether the available non-applicant supply is competitively priced and, hence, in the market.[10]

Requests for Rehearing

20. On rehearing, Southern contends that the Final Rule violates the requirement in FPA section 206 that the Commission bears the burden of proof in section 206 proceedings and that the Commission's determinations be based on substantial evidence.[11] According to Southern, this shifting of the burden of proof occurs through the use of indicative screens that Southern submits are inherently flawed and which, if failed, result in a presumption of market power that must be rebutted by sellers. Southern states that once a screen failure occurs and a presumption of market power arises, a seller only has two options: either accept a determination that it has market power and adopt cost-based rate mitigation measures, or provide the Commission with a DPT analysis.[12] Southern concludes that by applying the indicative screens codified in the Final Rule, the Commission will effectively shift to sellers the evidentiary burden in a section 206 proceeding.[13] Southern argues that the screens are inherently flawed in their ability to definitively assess market power when none is actually present, noting that the Final Rule acknowledges that the screens are conservative in nature and may result in false positives indicating market power.[14] Southern argues that because of their conservative nature and propensity to result in false positives, such screens cannot properly provide a basis for shifting the burden of proof to sellers, and are incapable of providing substantial evidence of market power.

21. To remedy this, Southern argues that the Commission should reconsider its determination in the Final Rule that a failure of an indicative screen results in a presumption of market power. Instead, the Commission should determine that the indicative screens are only intended to identify sellers that appear to raise no horizontal market power concerns and thus can be considered for market-based rate authority without the necessity of further analysis. In other words, passing the screens should raise a favorable presumption that a seller does not have market power, and a seller would never be ''presumed'' to have generation market power.[15]

22. Southern further argues that the Final Rule's market share screen and its application of the DPT are arbitrary and capricious, not supported by substantial evidence, without a rational basis, and contrary to established legal precedent.[16] Specifically, Southern contends that the market share screen and the DPT improperly fail to account for the size of the wholesale market demand that could be served by the uncommitted capacity in the relevant region.[17] Southern argues that wholesale market demand should be considered in the market share screen and the DPT because market power concerns only exist if a seller has the power to raise prices above competitive levels or exclude competition in the relevant market for a not insubstantial amount of time.[18] According to Southern, even the Department of Justice (DOJ) merger analysis, on which the Final Rule relies, would take the wholesale market into account when determining an entity's ''market share.'' [19] Southern comments that in the Final Rule the Commission appeared to give four reasons why it was unwilling to consider market demand (*i.e.*, contestable load), and contends that these reasons provide an insufficient basis for rejecting a contestable load analysis.[20] Southern believes that the weight of the evidence clearly demonstrates that to be legitimate indicators of market power, the market share screen and DPT should take the relevant wholesale demand into account.

Commission Determination

23. We disagree with Southern's contention that the Final Rule violates the requirement in the FPA that the Commission bears the burden of proof in section 206 proceedings. We also disagree with Southern's view that failure of the indicative screen(s) does not provide a sufficient basis to establish a rebuttable presumption of market power.

24. As a general matter, we agree that the burden of proof in a section 206 proceeding is on the Commission where the Commission institutes the proceeding on its own motion. However, we find Southern's argument that the burden of proof in a section 206 proceeding is unlawfully shifted to entities that fail one of the indicative screens to be without merit. As an initial matter, the burden of going forward is on the Commission in the first instance, and ultimately, when the Commission institutes a proceeding under section 206 of the FPA. In the Final Rule, the Commission has established through rulemaking a generic test to support its burden of going forward: A seller's failure of one of the indicative screens establishes a rebuttable presumption of market power. The burden of going forward then shifts to the seller once such a proceeding is initiated to rebut the presumption of market power. Once the seller submits additional evidence to rebut the presumption of market power, the Commission must determine, based on substantial evidence in the record, whether the seller has market power. Thus, the ultimate burden of proof under FPA section 206 remains with the Commission.[21] On this basis, the

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[10] Order No. 697 also dealt with the following issues, about which rehearing has not been sought: Control and commitment of generation resources; elimination of former 18 CFR 35.27, which had exempted newly-constructed generation from the horizontal market power analysis; reporting format for the indicative screens; nameplate capacity; and several procedural issues.

[11] Southern Rehearing Request at 7–8 (citing 16 U.S.C. 824e(a); *FPC* v. *Sierra Pacific Power Co.,* 350 U.S. 348 at 353 (1956) (*Sierra*); *Public Service Commission of New York* v. *FERC,* 642 F.2d 1335, 1345 (D.C. Cir. 1980); *Public Service Co. of New Mexico,* 115 FERC ¶ 61,090, at P 33 (2006)).

[12] *Id.* at 7 (citing Order No. 697 at P 63).

[13] *Id.* at 8.

[14] *Id.* (citing Order No. 697 at P 62, 71, 74, 89). Further, Southern asserts that only in instances of high market share should a prima facie case of market power be established, which would shift the burden of proof. *Id.* at 10 & n.10 (citing *U.S.* v. *Syufy,* 903 F.2d 659, 664 (9th Cir. 1990); *Hunt-Wesson Foods, Inc.* v. *Ragu Foods, Inc.,* 627 F.2d 919, 924 (9th Cir. 1980), *cert. denied,* 450 U.S. 921 (1981)).

[15] *Id.* at 11.

[16] *Id.* at 20 (citing 5 U.S.C. 706(2)(A) and (E) (2000); *Union Pac. Fuels, Inc.* v. *FERC,* 129 F.3d 157, 161 (D.C. Cir. 1997) (holding that review of Commission orders is made under the arbitrary and capricious standard of the Administrative Procedure Act); *Sithe Independence Power Partners* v. *FERC,* 165 F.3d 944 (D.C. Cir. 1999) (stating that the Commission must be able to demonstrate that it has ''made a reasoned decision based upon substantial evidence in the record'' and the ''path of [its] reasoning'' must be clear) (*quoting Town of Norwood* v. *FERC,* 962 F.2d 20, 22 (D.C. Cir. 1992)).

[17] *Id.* at 3–4 (citing *United States* v. *Grinnell Corp.,* 384 U.S. 563, 571 (1966); *MetroNet Services Corp.* v. *U.S. West Communications,* 329 F.3d 986 (9th Cir. 2003); *United States* v. *Dentsply International, Inc.,* 399 F.3d 181, 187 (3rd Cir. 2005)).

[18] *Id.* at 12–13.

[19] *Id.* at 13.

[20] *Id.* at 15 and Frame affidavit at ¶ 25, referring to Order No. 697 at P 66–67.

[21] *See AEP Power Marketing, Inc.,* 108 FERC ¶ 61,026, at P 30 (2004) (July 8 Order) (''Failure of a screen establishes a rebuttable presumption of market power, which satisfies the Commission's initial burden of going forward in such proceedings. The burden of going forward will then be upon the applicant once such a proceeding is initiated.''); *see Id.* P 29 (stating that passing both screens or failing one merely establishes a rebuttable presumption, and explaining that in the case of an intervenor in a section 205 proceeding that seeks to prove that the applicant possesses market power, ''the intervenor need only meet a 'burden of going forward' with

Continued

Commission is not unlawfully shifting the burden of proof to the seller that fails one of the screens.

25. Moreover, in Order No. 697, the Commission addressed an argument by Southern that failure of the screens does not provide a sufficient basis to establish a rebuttable presumption of market power, and Southern has failed on rehearing to convince us that a seller should never be presumed to have generation market power. In particular, the Commission explained that the indicative screens are intended to identify the sellers that raise no horizontal market power concerns and can otherwise be considered for market-based rate authority. Sellers failing one or both of the indicative screens, on the other hand, are identified as sellers that potentially possess horizontal market power and for which a more robust analysis is required. The Commission explained that the uncommitted pivotal supplier screen focuses on the ability to exercise market power unilaterally. Failure of this screen indicates that some or all of the seller's generation must run to meet peak load. The uncommitted market share analysis indicates whether a supplier has a dominant position in the market. Failure of the uncommitted market share screen may indicate that the seller has unilateral market power and may also indicate the presence of the ability to facilitate coordinated interaction with other sellers. It is on this basis that the Commission finds that a rebuttable presumption of market power is warranted when a seller fails one or both of the indicative screens. The screens themselves represent the first piece of evidence that the potential for market power exists since failure of one or both of the screens indicates that the seller may be a pivotal supplier in the market or has a high enough market share of uncommitted capacity to raise horizontal market power concerns.[22] In addition, we note that although we find that failure of an indicative screen is a sufficient basis to establish a presumption of market power, the Commission allows such a seller to continue to sell under market-based rate authority until a definitive finding is made, albeit with rates subject to refund to protect customers.

26. We disagree with Southern's argument that the indicative screens have a propensity to result in false positive indications of market power, do not provide substantial evidence of market power and, therefore, cannot provide a basis for shifting the evidentiary burden to sellers. As we explained in Order No. 697, the indicative screens are intended to screen out those sellers that raise no horizontal market power concerns and can otherwise be considered for market-based rate authority from those sellers that raise concerns but may not necessarily possess horizontal market power.[23] While we recognize that the conservative nature of the screens may result in some false positives, a conservative approach at the indicative screen stage is warranted because if a seller passes both of the indicative screens, there is a rebuttable presumption that it does not possess horizontal market power. Thus, we must weigh the risk of false positives and any resulting repercussions on a seller (e.g., section 206 proceeding, rate subject to refund, temporary regulatory uncertainty) against the costs of adopting a less conservative screen or eliminating the market share indicative screen.[24] In particular, if the screens result in a false positive indication of market power, the seller has the opportunity to rebut the presumption of market power while it continues to have market-based rate authority. However, if we were to adopt a less conservative screen, that could result in a false negative, *i.e.*, a false indication of no market power and customers would not be adequately protected. Accordingly, if the Commission were to adopt Southern's approach we are concerned that false negatives would become a reality and the Commission would not be able to fulfill its FPA section 205 and 206 mandate to ensure just, reasonable and not unduly discriminatory rates. On this basis, we believe that evidence of an indicative screen failure is sufficient to establish a rebuttable presumption of market power, in which case the seller will then have the opportunity to rebut that presumption of market power.

27. Additionally, in response to Southern's concerns regarding the conservative nature of the indicative screens, Order No. 697 changed the native load proxy under the market share indicative screen from the minimum native load peak demand for the season to the average of the daily native load peak demands for the season, making the native load proxy for the market share indicative screen consistent with the native load proxy under the pivotal supplier screen.[25] A native load proxy based on the average of peak load conditions is more representative, and thus more accurate, than a proxy based on minimum peak load conditions. Basing the native load proxy on the average of the peaks will make the screens more accurate in eliminating sellers without market power while focusing on ones that may have market power.[26] Thus, the updated native load proxy will reduce the likelihood that false positive indications of market power will occur.

28. Accordingly, we affirm our determination in the Final Rule that a failure of an indicative screen results in a presumption of market power, and reject Southern's proposal that a seller never be ''presumed'' to have horizontal market power as a result of an indicative screen failure.[27]

29. The Commission also disagrees with Southern's assertion that the market share screen and the DPT analysis do not account for the size of wholesale market demand, and are therefore arbitrary and capricious.[28] While Southern may disagree with our approach to considering wholesale market demand, both the market share screen and the DPT consider wholesale market demand by considering uncommitted capacity. Uncommitted capacity considers wholesale market demand by reducing the seller's available capacity by the amount of capacity committed to serve demand. In addition, in both the initial screen and the DPT, the Commission requires a pivotal supplier analysis, which looks at whether there is sufficient competing supply to serve wholesale demand.

30. In addition, we disagree with Southern that our choice of how to account for the wholesale market demand has resulted in the market share screen and the DPT being arbitrary and

evidence that rebuts the results of the screens. At that point, the burden of going forward would revert back to the applicant to prove that it lacks market power.'') (citing *Pennzoil Co.* v. *FERC,* 645 F.2d 360, 392 (5th Cir. 1981), *cert. denied,* 454 U.S. 1142 (1982); *accord Transcontinental Gas Pipe Line Corp.,* Opinion No. 135, 17 FERC ¶ 61,232, at 61,450 (1981) (''The presumption * * * is the same as that which arises from a prima facie case: It imposes on the party against whom it is directed the burden of going forward with substantial evidence to rebut or meet the presumption, but does not shift the burden of persuasion.''); *Generic Determination of Rate of Return on Common Equity for Electric Utilities,* Order No. 389–A, 29 FERC ¶ 61,223, at 61,458 (1984) (concluding that rebuttable presumption that a rate of return based on a benchmark is just and reasonable does not shift ultimate burden of proof imposed by Federal Power Act)); *see also Southern Companies Energy Marketing, Inc.,* 111 FERC ¶ 61,144, at P 24 (2005) (stating that a ''screen failure satisfies the Commission's burden of going forward and shifts to the applicant the burden of presenting evidence rebutting the presumption of market power''), *order dismissing reh'g as moot,* 119 FERC ¶ 61,300 (2007).

[22] *See* Order No. 697 at P 65.

[23] *Id.* P 62.

[24] *Id.* P 71.

[25] *Id.* P 135.

[26] *Id.* P 137.

[27] Southern Rehearing Request at 11.

[28] We further address Southern's arguments with regard to the DPT analysis below.

capricious. The development of the market share screen and the DPT resulted from lengthy public proceedings at which varying perspectives and arguments were taken into account. Over the years, and in light of the Commission's FPA responsibilities, the Commission has carefully considered various points of view in an open transparent dialogue with the electric industry and has based its determinations on sound regulatory principles. In particular, the market share screen provides a straightforward economically sound and accepted method to identify those sellers that have the potential to exercise market power.[29] The uncommitted pivotal supplier screen measures the ability of the firm to dominate the market at peak periods. Further, the market share screen indicates whether a supplier may have a dominant position in the market and measures the ability of a seller to affect coordinated interaction with other sellers that could be accomplished during both peak and off-peak times. The market share screen is useful in measuring market power because it measures a seller's size relative to others in the market, specifically, the seller's share of generating capacity that is uncommitted after accounting for its obligations to serve native load. It also provides a snapshot of these market shares in each season of the year.[30] Thus, the indicative screens measure a seller's market power at both peak and off-peak times and therefore indirectly measure market power potential during periods of both relatively high and low demand.[31] With regard to Southern's argument that in the Final Rule the Commission appeared to give four reasons why it was unwilling to consider market demand (*i.e.*, contestable load), and Southern's contention that these reasons provide an insufficient basis for rejecting a contestable load analysis, we reaffirm our determination that the contestable load analysis is flawed and essentially a variant on the pivotal supplier screen.[32] Like the pivotal supplier screen, the contestable load analysis addresses whether suppliers other than the seller can meet the demand in the relevant market. Thus, incorporating such an analysis would not improve our ability to establish a presumption of whether a seller possesses market power and would add little useful information.[33]

2. Indicative Market Share Screen Threshold Levels

Final Rule

31. Order No. 697 retained the 20 percent threshold for the wholesale market share screen (*i.e.*, with a market share of less than 20 percent, the seller passes the screen). The Commission reasoned that a relatively conservative threshold for passing the market share screen was appropriate, explaining that the screens are indicative of market power, not definitive. Responding to arguments that the Commission should use a 35 percent threshold as a presumption of market power because the U.S. Department of Justice (DOJ) merger guidelines state that only firms with 35 percent of more market share have market power, the Commission explained:

> In a market comprised of five equal-sized firms with 20 percent market shares, the HHI is 2,000, which is above the DOJ/FTC HHI threshold of 1,800 for a highly concentrated market, and in markets for commodities with low demand price-responsiveness like electricity, market power is more likely to be present at lower market shares than in markets with high demand elasticity.[34]

32. The Commission continued that, when arguing that a 20 percent threshold for the market share screen is too low, commenters ignored that the indicative screens are based on uncommitted capacity, not total capacity; as a result, a substantial amount of seller capacity may not be counted in measures of market share. The Commission, therefore, concluded that the 20 percent threshold strikes the right balance in seeking to avoid both false negative and false positive results.[35]

Requests for Rehearing

33. Southern asserts that the Final Rule arbitrarily utilizes a 20 percent market share threshold to establish a presumption of market power.[36] Further, Southern argues that the 20 percent threshold is contrary to legal precedent holding that a higher market share is required to warrant market power concerns.[37]

34. Southern argues that, contrary to the Commission's assertions, the 1984 Merger Guidelines do not support the 20 percent figure used in the market share screen. First, it states that while the particular sentence cited by the Commission from section 4.134 of the 1984 guidelines does actually contain the words ''market share of 20 percent,'' it does not support the application of a 20 percent threshold under the market share screen when considered in proper context, since other portions of the 1984 Merger Guidelines indicate that the DOJ's definition of ''market share'' in the context of merger evaluation is different from the Commission's definition of ''market share'' under its market share screen.[38] Second, Southern argues that according to the very sentence cited in the Final Rule from the 1984 Merger Guidelines, the 20 percent ''market share'' threshold refers only to the market share of the *acquired firm* in the overall context of a proposed merger of multiple firms. It does not refer to the market share of the merged firm post-acquisition, nor does it even refer to the market share of the acquiring firm. Third, Southern argues that the Commission's reliance on the 20 percent threshold in section 4.134 of DOJ's 1984 Merger Guidelines is misplaced because that provision is outdated—it is not included in DOJ's *current* horizontal merger guidelines. In this regard, the 1984 Merger Guidelines were used to evaluate both *vertical and horizontal* mergers. The newer versions of DOJ's *horizontal* merger guidelines subsequently adopted in 1992 and 1997 do not carry forward section 4.134's 20 percent market share threshold. Thus, the market share of a single firm does *not* automatically translate into a high HHI as the Commission suggests.[39]

35. Southern also argues on rehearing that section 2 of the Sherman Antitrust Act, which prohibits not only actual

[29] *See In the Matter of Merger Policy Under the Federal Power Act*, May 7, 1996, Comments of the U.S. Department of Justice, Docket No. RM96–6–000 (providing comments on the Commission's standards for determining whether a proposed merger is in the public interest, recommending that the Commission apply a market share screen to identify quickly those mergers that are unlikely to raise competitive issues and concluding that the Horizontal Merger Guidelines provide ''sound competitive analysis''); *see also* U.S. Department of Justice and the Federal Trade Commission, Horizontal Merger Guidelines, section 2.0, reprinted at 4 Trade Reg. Rep. (CCH) ¶ 13,104 (Issued April 2, 1992, Revised April 8, 1998).

[30] Order No. 697 at P 65.

[31] *Id.*

[32] *Id.* P 66.

[33] *Id.*

[34] *Id.* P 89.

[35] *Id.* P 91.

[36] Southern Rehearing Request at 4 (citing DOJ 1984 Merger Guidelines, Section 2.4; *Edison Mission Energy, Inc.* v. *FERC*, 394 F.3d 964, 968 (D.C. Cir. 2005) (stating that the Commission must ''articulate a satisfactory explanation for its action including a 'rational connection between the facts found and the choice made.' '') (quoting *Motor Vehicle Mfrs. Ass'n* v. *State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983)).

[37] *Id.*

[38] The Final Rule cited section 4.134, stating ''[t]he 20 percent threshold is consistent with § 4.134 of the U.S. Department of Justice 1984 Merger Guidelines issued June 14, 1984, reprinted in Trade Reg. Rep. P 13,103 (CCH 1988): 'The Department [of Justice] is likely to challenge any merger satisfying the other conditions in which the acquired firm has a market share of 20 percent or more.' '' Order No. 697 at n.21.

[39] *Id.* at 16–19.

monopolization but also attempted monopolization and conspiracy to monopolize, has spawned a well-established body of law to address the type of market concerns that the Commission attempts to address in the Final Rule. Southern contends that the Commission's 20 percent threshold falls short when measured against the jurisprudence interpreting section 2 of the Sherman Act and that a more relevant threshold in a non-merger context would arguably be closer to 90 percent than 20 percent.[40] Whether the Commission's concern arises out of the unilateral ability of a utility to exert market power or the ability of two or more utilities to act concertedly in a way that restrains trade, Southern argues that jurisprudence interpreting the Sherman Act more appropriately addresses those concerns than does merger analysis. Aside from the authorities supporting a rule of law that less than at least a 50 percent market share should be insufficient to suggest market power, Southern argues that many cases and commentators may be cited for the proposition that the Commission's 20 percent threshold is misguided and lacks a rational basis; relatively low market shares should, as a matter of law, preclude findings of market power.[41] Southern adds that the courts have not only consistently held that market shares in the 20 percent range are insufficient to support a finding of actual monopoly power under section 2 of the Sherman Act, but also have found little difficulty in determining that such market share is not enough to sustain even a claim of attempted monopolization under section 2.[42]

36. NASUCA argues on rehearing that in calculating market share when screening for horizontal market power, the Commission should not subtract capacity needed for long-term contracts as ''committed'' if the contracts are indexed or linked to spot market prices. NASUCA asserts that a seller with a market share of capacity greater than 20 percent can reduce it, and pass a market power screen it would otherwise fail, by ''committing'' portions of its capacity. NASUCA states that it requested in its NOPR comments that the Commission clarify that it will not consider capacity dedicated to meeting long-term contract sales of energy to be ''committed''—and thus disregarded from market share—if the price of energy in the long-term contracts is indexed or linked to spot market prices. NASUCA contends that it identified relevant research in support of its request in citing a model that withdraws the capacity committed under the long-term contracts from the short-run market.[43] NASUCA states that the Commission overlooked NASUCA's request, and therefore requests that the Commission grant its requested clarification because research indicates that long-term contracts linked to spot market prices do not reduce, and may exacerbate, the ability of a seller to raise spot market prices above competitive levels.[44] In the alternative, NASUCA seeks further proceedings to examine the exercise of market power by sellers who pass market screens due to their contractual commitment to make long-term energy sales at rates indexed to spot market prices.

Commission Determination

37. We affirm our determination to retain the 20 percent threshold for the indicative wholesale market share screen. Use of the 20 percent market share threshold is appropriate since the screen is indicative, not dispositive. Southern's arguments suggest that the 20 percent is dispositive, but it is not. If a seller fails the indicative screens, it can submit a full DPT analysis in which a range of factors are considered, including market shares, HHIs (market concentration) and other factors affecting the relevant markets. A 20 percent market share is not even considered dispositive at that stage; rather, we have approved market-based rates in several cases where a supplier had a market share exceeding 20 percent.[45] In addition, we note that the cases cited by Southern, where much higher market shares were allowed, involve markets other than electricity.[46] Electricity markets possess unique characteristics including, but not limited to, inelastic demand and the need to balance the entire transmission grid in real-time. Economic theory and empirical estimates of the short-run elasticities of electricity demand suggest that these unique conditions allow sellers in wholesale electricity markets to exercise market power using a much more limited withholding of supply than industries listed in the cases cited by Southern.[47] Thus, the use of a conservative threshold such as a 20 percent market share is warranted, particularly for an indicative screen.

38. Southern asserts that the Final Rule's reliance on the 1984 Merger Guidelines for use of the ''20 percent market share'' is incorrect. Section 4.134 of the 1984 Merger Guidelines states:

> Entry through the acquisition of a relatively small firm in the market may have a competitive effect comparable to new entry. Small firms frequently play peripheral roles in collusive interactions, and the particular advantages of the acquiring firm may convert a fringe firm into a significant factor in the market. The Department is unlikely to challenge a potential competition merger when the acquired firm has a market share of five percent or less. Other things being equal, the Department is increasingly likely to challenge a merger as the market share of the acquired firm increases above the threshold. The Department is likely to challenge any merger satisfying the other conditions in which the acquired firm has a market share of 20 percent of [sic] more.[48]

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[40] *Id.* at 20 (citing *Hiland Dairy* v. *Kroger*, 402 F.2d 968, 976 (8th Cir. 1968) (rejecting 60 or 33 percent market share); *Robinson* v. *Magovern*, 521 F. Supp. 842, 887 (W.D. Pa. 1981)).

[41] *Id.* at 22–23 (citing *Cargill, Inc.* v. *Monfort of Colorado, Inc.*, 479 U.S. 104, 119 n.15 (1986) (noting that 20.4 percent market share is probably insufficient to sustain predatory pricing, and citing authorities indicating that 60 percent or more would be necessary); *Bailey* v. *Allgas, Inc.*, 284 F.3d 1237, 1250 (11th Cir. 2002); *Yoder Bros., Inc.* v. *California-Florida Plant Corp.*, 537 F.2d 1347, 1368 (5th Cir. 1976) (stating that a 20 percent market share was insufficient as a matter of law to prove market power)).

[42] *Id.* at 24 (citing *H.L. Hayden Co. of New York, Inc.*, v. *Siemens Medical Systems, Inc.*, 879 F.2d 1005, 1017 (2nd Cir. 1989); *Nifty Foods Corp.* v. *Great Atl. & Pac. Tea Co.*, 614 F.2d 832, 841 (2nd Cir. 1980) (one-third market share not enough); *U.S.* v. *ALCOA*, 148 F.2d 416, 424 (2nd Cir. 1945).

[43] NASUCA Rehearing Request at 8 (citing Chloe Lo Coq. *Index Contracts and Spot Market Competition,* University of California Energy Institute, Center for the Study of Energy Markets, June 2006, p. 15, available at *http://www.ucei.berkeley.edu/ThirdTierButtons/PDFButton_Off.jpg*).

[44] *Id.* (citing Order No. 697 at P 82–93).

[45] *PPL Montana, LLC,* 115 FERC ¶ 61,204, at P 41 (2006), *order denying reh'g,* 120 FERC ¶ 61,096 (2007); *Kansas City Power and Light Co.,* 113 FERC ¶ 61,074, at P 26, 30 (2005); *PacifiCorp,* 115 FERC ¶ 61,349, at P 29, 32 (2006); *Tampa Electric Co.,* 117 FERC ¶ 61,311, at P 26–27 (2006).

[46] *Hiland Dairy* v. *Kroger,* 402 F.2d 968 (8th Cir. 1968) (concerning a claim of monopolization in the milk and dairy business); *Robinson* v. *Magovern,* 521 F. Supp. 842 (W.D. Pa. 1981) (addressing an antitrust action against a hospital); *Cargill, Inc.* v. *Monfort of Colorado, Inc.,* 479 U.S. 104 (1986) (concerning a merger in the beef packing industry); *Bailey* v. *Allgas, Inc.,* 284 F.3d 1237 (11th Cir. 2002) (addressing an antitrust action arising from a price war between liquid propane gas competitors); *Yoder Bros., Inc.* v. *California-Florida Plant Corp.,* 537 F.2d 1347 (5th Cir. 1976) (addressing antitrust claims arising from infringement of plant patents); *H.L. Hayden Co. of New York, Inc.,* v. *Siemens Medical Systems, Inc.,* 879 F.2d 1005 (2nd Cir. 1989) (addressing antitrust claims relating to distribution of dental x-ray equipment); *Nifty Foods Corp.* v. *Great Atl. & Pac. Tea Co.,* 614 F.2d 832 (2nd Cir. 1980) (concerning an antitrust suit arising from the substitution of a supplier of frozen waffles); *U.S.* v. *ALCOA,* 148 F.2d 416 (2nd Cir. 1945) (concerning claims of monopolization of interstate and foreign commerce in the manufacture and sale of aluminum).

[47] Energy Information Administration, ''Assumptions to the Annual Energy Outlook 2006,'' Report #: DOE/EIA–0554 (2006); James A. Espey & Molly Espey, ''Turning on the Lights: A Meta-analysis of Residential Electricity Demand Elasticities,'' Journal of Agricultural and Applied Economics, 36:1, at 65–81 (April 2004).

[48] U.S. Department of Justice Non-Horizontal Merger Guidelines sec. 4.134, originally issued June 14, 1984, as part of the U.S. Department of Justice

39. Upon further review, the context discussed in this quote differs from the issue before us, and provides little guidance here. In the market-based rate context, we focus on whether the applicant has a 20 percent market share as a conservative measure because of the electricity market's characteristics including inelastic demand and the need to balance the entire transmission grid in real-time.[49] However, the Non-Horizontal Merger Guidelines provide that a firm with a 20 percent share is unlikely to be a ''fringe'' firm and an insignificant factor in the market. This is the same reason that we use the 20 percent threshold in our indicative screen: Firms with a 20 percent market share would be unlikely to hold a dominant position in the market.[50]

40. We also reject Southern's argument that the Commission's 20 percent threshold falls short when measured against the jurisprudence interpreting section 2 of the Sherman Act.[51] Economic theory suggests that it may be possible, given the unique conditions in electricity markets, for sellers to exercise market power, using a much more limited withholding of supply, than industries listed in the cases relied upon by Southern.[52] Moreover, in contrast to the cases cited, the Commission uses 20 percent as an *indicative* screen, not as a dispositive factor in determining whether market power exists. We have, as indicated, approved market-based rates for firms with market shares in excess of 20 percent.

41. We reject NASUCA's request that the Commission require sellers to treat capacity that is committed to long-term contracts that are indexed or linked to spot market prices as uncommitted capacity in calculating market share when screening for horizontal market power. As support, NASUCA cites a model that withdraws the capacity committed under the long-term contracts from the short-run market, and then concludes that the now reduced capacity traded in the spot market lowers the incentives for rival firms to deviate from any collusive behavior by reducing the number of firms in the market and their available capacity.[53] Therefore, the model cited by NASUCA subtracts capacity committed under long-term contracts from the capacity available in the short-run market, just as we do in our analysis. Similarly, the Commission believes that once capacity is committed long-term, regardless of how that capacity is priced (e.g., whether linked to spot prices or not), the ability of the firm to use that capacity to exercise market power in the spot market is severely limited or non-existent. The ability to collude will be determined by the remaining uncommitted capacity in the spot market, not the capacity that is already committed under long-term contracts. Therefore, we conclude that it is appropriate to subtract capacity committed under long-term contracts when calculating a seller's uncommitted capacity for purposes of performing the indicative screens.

3. DPT Criteria

Final Rule

42. In Order No. 697, the Commission announced that it would continue to use the DPT to make a definitive determination of whether a seller has market power and that it would continue to weigh both available economic capacity and economic capacity when analyzing market shares and Hirschman-Herfindahl Indices (HHI).[54] The Commission chose to retain the HHI threshold of 2,500 for passing the DPT, and to retain the 20 percent market share threshold. Responding to arguments that if a 2,500 HHI threshold is retained, it should be used with a 15 percent market share because these are the criteria of the oil pipeline test from which the 2,500 HHI was derived, the Commission noted that it ''had not seen cases where the HHI was over 2,500 and the seller's market share was between 15 and 20 percent, which would be the type of situation about which [commenters] are concerned.'' [55]

Requests for Rehearing

43. Montana Counsel argues that the Commission should clarify that capacity committed to a competitor's native load or otherwise unavailable on a firm basis should not be considered available to compete with the applicant's generation, and as such should not be included as available capacity in the DPT analysis. Montana Counsel states that in its order on PPL Montana's request for renewal of market-based rate authority, the Commission stated that it was ''not inconsistent with how DPTs have historically been conducted'' for PPL Montana to include as available competing generation capacity that was committed elsewhere.[56] Montana Counsel contends that this is inappropriate insofar as generation committed to serve another utility's native load cannot be available to compete with the applicant's generation on a firm basis. Montana Counsel states that while it appears that Order No. 697 remedies this mistake in stating that total supply is determined by adding the total amount of uncommitted capacity located in the relevant market (including capacity owned by the seller and competing suppliers) with that of uncommitted supplies that can be imported (limited by simultaneous transmission import capability) into the relevant market from the first-tier markets, the Commission does not explicitly change the Commission's prior policy.[57] Accordingly, Montana Counsel requests clarification that the Commission will not allow applicants to count as available economic capacity generation that is in fact committed; if necessary and in the alternative, Montana Counsel requests rehearing of this issue.

44. TDU Systems argue on rehearing that the Final Rule fails to explain how the adoption of a 2,500 HHI threshold is rationally related to the Commission's objective of precluding market-based rates in highly concentrated markets.[58] They assert that the Commission should lower the HHI threshold to 1,800 as the appropriate threshold for treating a market as highly concentrated, and that the Commission's refusal to do so in the Final Rule was arbitrary and capricious. TDU Systems state that, since the Commission set out in the Final Rule ''to provide 'a rigorous up-front analysis of whether market-based rates should be

Merger Guidelines, reprinted in Trade Reg. Rep. ¶ 13,103 (CCH 1988) (footnote omitted).

[49] A seller who has less than a 20 percent market share in a season will be considered to satisfy the market share analysis. *AEP Power Marketing, Inc.*, 107 FERC ¶ 61,018, at P 102 (April 14 Order), *order on reh'g*, 108 FERC ¶ 61,026 (2004) (July 8 Order).

[50] *See Id.* P 104.

[51] Southern Rehearing Request at 22–23.

[52] *See supra* n.46.

[53] ''If collective action is necessary for the exercise of market power, as the number of firms necessary to control a given percentage of total supply decreases, the difficulties and costs of reaching and enforcing an understanding with respect to the control of that supply might be reduced.'' U.S. Department of Justice and the Federal Trade Commission, Horizontal Merger Guidelines, section 2.0, reprinted at 4 Trade Reg. Rep. (CCH) ¶ 13,104 (Issued April 2, 1992, Revised April 8, 1998).

[54] Order No. 697 at P 13, 104, 106.

[55] *Id.* P 113.

[56] Montana Counsel Rehearing Request at 9 (citing *PPL Montana, LLC,* 115 FERC ¶ 61,204, at P 49 (2006)).

[57] *Id.* at 10 (citing Order No. 697 at P 37–38).

[58] TDU Systems state that ''The Final Rule fails to explain how the adoption of an 1,800 Herfindahl-Hirschman Index ('HHI') threshold is rationally related to its objective of precluding market-based rates in highly concentrated markets. TDU Systems Rehearing Request at 2 (citing *Motor Vehicle Mfrs. Ass'n* v. *State Farm Mut. Auto Ins. Co.,* 463 U.S. 29, 42–43 (1983); *Pac. Gas & Elec. Co.* v. *FERC,* 373 F.3d 1315, 1319 (D.C. Cir. 2004)). However, the Final Rule retained 2,500 as the appropriate threshold for passing the HHI component of the DPT.

granted,' it is somewhat puzzling as to why the Commission believes that the case for any change in the status quo must be 'compelling.' "[59]

45. TDU Systems note that 1,800 is the level which the Commission uses in its merger regulations and contends that the Commission placed too much reliance on the 1994 DOJ recommendations[60] as to market rates in the very different oil pipeline market for arriving at the 2,500 HHI threshold. TDU Systems state that electric utilities do not face the same competition from other modes of transportation and demand elasticity as do oil pipelines. They state that these factors support their argument for a lower HHI.[61] If the Commission does not adopt the 1,800 level consistent with effective competition, TDU Systems contend that it should reduce the market-share threshold to 15 percent.[62]

46. TDU Systems argue that they made a strong case for reducing the triggering HHI level to 1,800 in their NOPR comments, and that the Commission appears not to have considered it carefully. They assert that if a market is regarded as "highly concentrated," the DOJ guidelines indicate that even modest increases in concentration will likely raise significant competitive concerns. They contend that, in such a market, other agencies presume that an HHI increase of 100 or more is likely to create or enhance market power. They conclude that, regardless of what the Commission ordered in the April 14 Order, there is no good reason at this time to regard a market with a 2,000 HHI as not highly concentrated.[63]

47. Southern argues that for the same reasons that the market share screen should take into account the overall size of the wholesale market and include a contestable load analysis, the DPT should take into account the overall size of the wholesale market, or should be replaced by a contestable load analysis.[64]

Commission Determination

48. In response to the Montana Counsel's request, we clarify that capacity committed to a competitor's native load or otherwise unavailable on a long-term firm basis, will not be considered available to compete with the seller's generation, and as such will not be included as available economic capacity in the DPT analysis. We also note that Montana Counsel misrepresents our findings in the PPL Montana proceeding. In that proceeding, it was not argued that the capacity in question was committed elsewhere. Rather, the Commission addressed the argument that capacity "may" be committed. PPL Companies rebutted that argument by explaining that the buyers at issue did not have long-term firm transmission available to export the energy in question from the NorthWestern control area, and that because the buyers could elect to leave this capacity in the NorthWestern control area, the capacity in question should not be excluded from the available economic capacity in the NorthWestern control area. The Commission noted that PPL Companies' treatment of this capacity is not inconsistent with how DPTs have historically been conducted.

49. The Commission rejects TDU Systems' proposal to reduce the HHI threshold level to 1,800. The Commission will continue to use a 2,500 HHI and a 20 percent market share as the thresholds for the DPT analysis. The Commission believes that the market share/HHI thresholds of 20 percent and 2,500, respectively, enable the Commission to identify dominant firms in highly concentrated markets, rather than firms with market shares above 20 percent that operate in less concentrated markets (e.g., HHIs less than 2,500), resulting in fewer false positives.[65] Further, the Commission will continue to examine each DPT analysis on a case-by-case basis, weighing other factors, besides market share and HHIs, such as historical sales and transmission data.[66] Thus, we will retain 2,500 as the appropriate threshold for passing the HHI component of the DPT.[67] Notwithstanding TDU Systems' argument that the Final Rule fails to explain how the adoption of a 2,500 HHI threshold is rationally related to the Commission's objective of precluding market-based rates in highly concentrated markets, the Commission has explained why 2,500 is the appropriate threshold, and we reject TDU Systems' contention that the Commission did not carefully consider arguments for reducing the threshold to 1,800. At less than 2,500 HHI in the relevant market for all season/load conditions, there is little likelihood of coordinated interaction among suppliers in a market.[68] TDU Systems argue that the DOJ Merger Guidelines use an 1,800 HHI, but fail to note that the focus of the Guidelines is on *increases* in market concentration produced by a merger. For example, an existing market could have an HHI of 2,400 and the DOJ would take no action if the acquired firm was very small. It is therefore not the 1,800 HHI figure, standing alone, that merits scrutiny by the DOJ, but rather the relative *increase* in concentration that could cause the DOJ to investigate further. We therefore do not believe that our approach conflicts in any way with the DOJ merger guidelines. We also reaffirm our determination not to adopt TDU Systems' suggestion to lower the market share threshold to 15 percent from 20 percent. As we explained, we believe that the 20 percent threshold strikes the right balance in seeking to avoid both false negatives and false positives.[69]

50. With regard to Southern's argument that the DPT should take into account the overall size of the wholesale market or be replaced by a contestable load analysis, the Commission reaffirms its determination that the contestable load analysis is essentially a variant on the pivotal supplier screen, and therefore redundant. As a variant of the pivotal supplier screen, the contestable load analysis has differences in the calculation of wholesale load and the test thresholds. Like the pivotal supplier screen, it addresses whether suppliers other than the seller can meet the demand in the relevant market. Incorporating such an analysis would not improve our ability to establish a presumption of whether a seller possesses market power and would add little useful information.[70] In addition, because the indicative screens measure a seller's market power at both peak and off-peak times, they therefore measure market power potential during periods of both high and low demand, and this concern need not be addressed in the DPT.[71]

51. We also reject Southern's argument that the DPT should be replaced by the contestable load analysis. First, unlike the DPT, the contestable load analysis fails to consider relative prices of competing

[59] *Id.* at 12–13 (citing Order No. 697 at P 2).

[60] April 14 Order, 107 FERC ¶ 61,018, at P 110 & n.96 (citing Comments of the U.S. Dept. of Justice, Docket No. RM94–1–000 (Jan. 18, 1994)).

[61] TDU Systems Rehearing Request at 14.

[62] *Id.* at 6–7 (citing DOJ Comments, Docket No. RM94–1–000 (Jan. 18, 1994), at 13).

[63] *Id.* at 13.

[64] Southern Rehearing Request at 3–4, 11–16 and Frame Affidavit at ¶ 5, 21–22.

[65] As explained in Order No. 697 at P 100, lowering the HHI threshold to 1,800 will cause more false positives and direct capital away from the generation sector.

[66] Order No. 697 at P 96.

[67] *Id.* P 113; April 14 Order, 107 FERC ¶ 61,018, at P 111.

[68] April 14 Order, 107 FERC ¶ 61,018 at P 111.

[69] Order No. 697 at P 113; July 8 Order, 108 FERC ¶ 61,026 at P 95–97; NOPR at P 41.

[70] Order No. 697 at P 66.

[71] *Id.* P 65–66.

suppliers.[72] Second, contrary to Southern's claim, the DPT does consider wholesale load because it analyzes ten different seasons/load periods and the Available Economic Capacity (AEC) analysis deducts the native load commitments of all suppliers, which includes wholesale commitments.

4. Other Products and Models

Final Rule

52. Regarding relevant product markets, the Commission stated in the Final Rule:

> [w]e will not generically alter the indicative screens or the DPT to allow different product analyses for short-term or long-term power as some commenters suggest. As the Commission has stated in the past, absent entry barriers, long-term capacity markets are inherently competitive because new market entrants can build alternative generating supply. There is no reason to generically require that the horizontal analysis consider those products that are affected by entry barriers. Instead, we will consider intervenors' arguments in this regard on a case-by-case basis.[73]

53. The Commission also rejected suggestions by some commenters that it adopt behavioral modeling, such as game theory, in addition to or in place of the indicative screens and the DPT. The Commission explained that, although game theory has been used in laboratory experiments and in theoretical studies where the number of players and choices available to players are limited, it is not a practical approach given the volume of analyses the Commission must perform. The Commission noted that a large number of choices are available in market power analyses and many of those are unobservable, and concluded that data gathering and analysis burden imposed on sellers and the Commission if it were to adopt behavior modeling would be overly burdensome and impractical.[74]

Requests for Rehearing

54. NASUCA argues that the Commission must investigate whether sellers are able to raise electricity auction market rates to higher non-competitive levels, without collusion, through strategic bidding and gaming behavior in Commission-approved auction markets.[75] NASUCA states that experience, mathematical game theory analysis, judicial decisions, and laboratory simulations indicate that market participants who pass market power screens nonetheless may be able to elevate prices in Commission-approved auction markets through non-collusive strategic bidding, withholding, and gaming tactics.[76] NASUCA states that the Commission's market power screens are based on a static analysis of single sellers' market shares, stating that less than a 20 percent share of the relevant market capacity is sufficient and less than the supply margin on the annual peak day satisfies the ''supply margin assessment.'' NASUCA concludes that neither of these tools addresses the problem identified in the research that sellers in these specialized markets repeatedly communicate through their bidding behavior.[77]

55. NASUCA states that, to its knowledge, the Commission has never publicly discussed mathematical game theory analysis in depth in its orders, has not investigated the problem, and has held no technical conference or workshop to invite researchers to present their findings regarding gameability of the wholesale electricity markets.[78] NASUCA argues that strategic market behavior analysis is needed to assess whether current market designs allow participants, without overt collusion, to elevate market prices to unreasonable and non-competitive levels. The purpose of such analysis would be to take corrective action to prevent gaming behavior, by revising market designs or rules. NASUCA asserts that the Commission misunderstood NASUCA's request in finding that consideration and analysis of such behavior would be burdensome.[79]

56. NASUCA argues that the ''primary purpose'' of the FPA and the Commission is protection of utility consumers. NASUCA states that, in order to achieve confidence that rates set in Commission-sanctioned markets are reasonable, the Commission must investigate strategic bidding and market gaming by market participants.[80] NASUCA therefore requests that, at a minimum, the Commission commence a proceeding to investigate this and begin it by inviting researchers who have identified strategic auction market gaming as a problem in auction markets of the type used for the sale of electricity to present their research at a public technical conference.

57. APPA/TAPS argue that, in addition to the existing indicative screens, the Commission should require that the market share screen be submitted using only firm transmission capacity.[81] In this regard, APPA/TAPS state that applicants should be required to ''submit a 'firm transmission Market Share Screen' where the SIL [simultaneous transmission import limit] study reflects only firm transmission capacity.'' [82] According to APPA/TAPS, running the market share screen using only firm transmission in the SIL study would provide evidence about who could realistically compete to sell long-term, firm products. Further, APPA/TAPS argue that the pivotal supplier screen is not well adapted to examining market conditions for long-term products, and that the firm transmission market share screen could be performed to provide better insight into the market for long-term products. APPA/TAPS assert that to understand what long-term generation capacity may be available and backed by firm transmission service, the market share screen should be run using an SIL study of firm transmission capacity only, preferably using available transfer capability (ATC) for the upcoming annual period, but at a minimum, run without capacity benefit margin (CBM) modeled as available, even on a non-firm basis.[83] APPA/TAPS also argue that the Commission should require sellers to calculate the simultaneous available import capability of their systems using the firm ATC values that transmission customers are given, and use those results to prepare one of the iterations of the market share screen.[84]

Commission Determination

58. We have considered the strategic bidding literature and various theoretical models which demonstrate that market participants who pass market power screens nonetheless may be able to elevate prices in Commission-approved auction markets through ''non-collusive strategic bidding, withholding, and gaming tactics.'' However, the Commission does not think it is necessary to investigate the possibility of whether sellers or market participants are able to engage in strategic bidding, withholding and gaming tactics to elevate prices in auction markets in order to determine whether to grant market-based rate authority. First, these theoretical or gaming models require consideration of numerous assumptions and hypothetical future behavior that may quickly become invalid because of the

[72] *Id.* P 67.

[73] *Id.* P 122.

[74] *Id.* P 124.

[75] NASUCA Rehearing Request at 5.

[76] *Id.* at 2.

[77] *Id.* at 6.

[78] *Id.* at 7 (citing Order No. 697 at P 121, 124).

[79] *Id.* at 7 (citing Order No. 697 at P 124).

[80] *Id.* (citing *Electrical Dist. No. 1* v. *FERC*, 774 F.2d 490, 492–93 (D.C. Cir. 1984)).

[81] APPA/TAPS Rehearing Request at 13.

[82] *Id.*

[83] *Id.* at 16.

[84] *Id.* at 17.

changing behavior of market participants, changes in the market or changes in other factors, e.g., supply or demand. Accordingly, the Commission is concerned that they would not be reliable tools in helping assess whether a seller has market power. Second, the type of behavior described by NASUCA may be prohibited by the Commission's Anti-Manipulation Rule at section 1c.2 of the Commission's regulations.[85] Violations of the Anti-Manipulation Rule include behavior constituting a fraud that had the purpose of impairing, obstructing, or defeating a well-functioning market.[86] The Commission's Office of Enforcement monitors activity in the electric markets and conducts investigations to determine whether market participants are violating the Anti-Manipulation Rule. To the extent that NASUCA or any other entity has specific allegations of market manipulation, that entity should contact the Commission's Enforcement Hotline or the Division of Investigations of the Office of Enforcement. Finally, as the Commission stated in Order No. 697, for practical considerations the data gathering and analysis burden imposed on sellers and the Commission to consider all the hypothetical types of behavior would be overly burdensome and impractical.[87]

59. With regard to APPA/TAPS' argument that the existing indicative screens should be altered so that sellers are required to ''submit a 'firm transmission Market Share Screen' where the SIL study reflects only firm transmission capacity'' in order to examine market conditions for long-term products, we reiterate that the indicative screens are intended to identify sellers that raise no horizontal market power concerns in short-term markets, and we decline to allow different product analyses for short-term or long-term power. We address the issue of the analysis of the competitiveness of long-term markets in the section of this order addressing mitigation. Thus, we reject APPA/TAPS' argument that sellers should be required to submit a firm transmission market share screen where the SIL study reflects only firm transmission capacity.

5. Native Load Deduction

Final Rule

60. In Order No. 697, the Commission modified the native load proxy for the market share screen from the minimum peak day in the season to the average peak native load, averaged across all days in the season, making the native load proxy for the market share indicative screen consistent with the native load proxy under the pivotal supplier indicative screen. The Commission found that using the existing native load proxy did not provide an accurate picture of the conditions throughout the season. The Commission explained that a native load proxy based on the average of peak load conditions is more representative, and thus more accurate, than a proxy based on extreme (minimum) peak load conditions, and further, that basing the native load proxy on the average of the peaks is more accurate by eliminating sellers without market power while focusing on ones that may have market power.

61. In addition, the Commission clarified that native load can only include load attributable to native load customers based on the definition of native load in section 33.3(d)(4)(i) of the Commission's regulations and gave sellers the option of using seasonal capacity instead of nameplate capacity.

Requests for Rehearing

62. TDU Systems assert on rehearing that the Commission's failure to explain how its modification of the native load proxy in the wholesale market share screen is rationally related to the objective of accurately detecting the market power of electric utilities in their home control areas is arbitrary and capricious.[88]

63. TDU Systems argue that the Commission should maintain the existing native load proxy for use in the wholesale market share screen [89] because the Commission does not provide a reasoned analysis and supporting evidence for increasing the native load proxy for the market share indicative screen from the minimum daily native load peak demand for the season to the average daily native load peak demand for the season.[90]

64. TDU Systems point out the Commission's explanation that the virtue of having the two indicative screens is that they each measure different market conditions,[91] and assert that, to achieve that purpose, they should use different proxies for native load obligations. TDU Systems conclude that the Commission should revise the market share screen to use the minimum native load during the season as the proxy.[92]

Commission Determination

65. In response to TDU Systems' assertion that changing the native load proxy is arbitrary and capricious and may not accurately detect the market power of electric utilities in their home balancing authority areas, we acknowledge that increasing the native load proxy may have the effect of reducing the market share for traditional utilities and could result in fewer failures of the market share screen.[93] However, as we explained in Order No. 697, the native load proxy adopted in Order No. 697 more accurately describes the conditions faced by sellers across seasons rather than simply at the most extreme peak load conditions.[94] For instance, using the minimum peak day in the native load proxy only measures sellers' available capacity on a single day, and does not reflect the more general conditions faced by sellers throughout the season. Because changing the native load deduction will lead to a more accurate measure of uncommitted capacity for load-serving entities, there will be a more accurate measure of the conditions faced by competing suppliers. Thus, the native load proxy is more accurate in detecting the market power of electric utilities in their home balancing authority areas.

66. We reject TDU Systems' argument that because the pivotal supplier and market share screens measure different market conditions they should therefore use different native load proxies. We disagree and find that is not appropriate to use different native load proxies for the different screens. Although the screens themselves use inherently different methodologies, the native load does not vary depending on which

[85] *Prohibition of Energy Market Manipulation*, Order No. 670, 71 FR 4244 (Jan. 26, 2006), FERC Stats. & Regs. ¶ 31,202 (2006), *reh'g denied*, 114 FERC ¶ 61,300 (2006).

[86] Order No. 670, FERC Stats. & Regs. ¶ 31,202 at P 50–53.

[87] Order No. 697 at P 124.

[88] TDU Systems Rehearing Request at 3 (citing *Motor Vehicle Mfrs. Ass'n* v. *State Farm Mut. Auto Ins. Co.*, 463 U.S. 29, 42–43 (1983); *Pac. Gas & Elec. Co.* v. *FERC*, 373 F.3d 1315, 1319 (D.C. Cir. 2004)).

[89] *Id.* at 7.

[90] *Id.* at 8, 18.

[91] April 14 Order, 107 FERC ¶ 61,018 at P 90 (2004).

[92] TDU Systems Rehearing Request at 20.

[93] We note that use of the average daily native load peak demand for the season is also applicable to first-tier competitors. Thus, while a traditional utility applicant will have a lower amount of uncommitted capacity than it would have had using a native load proxy based on the minimum daily native load peak demand for the season, so too will traditional utility sellers in first-tier markets. Accordingly, although the traditional utility applicant's uncommitted capacity is reduced, so too is the relative size of the market considering imports from first-tier markets. All else being equal, the market shares of the traditional utility applicant may not change much if at all.

[94] 94 Order No. 697 at P 137.

screen is used. Accordingly, we find that use of the average peak native load as the native load proxy for both screens provides an accurate picture of the conditions throughout the season.

67. We also clarify the definition of native load as it is used in the DPT analysis. With regard to the statement in the Final Rule that under the DPT, a seller "will be considered pivotal if the sum of the competing suppliers' economic capacity is less than the load level (plus a reserve requirement that is no higher than State and Regional Reliability Council operating requirements for reliability) for the relevant period" [95] we clarify that the analysis should also be performed using available economic capacity to account for sellers' and competing suppliers' native load commitments. We further clarify that native load in the relevant market (sellers' and competing suppliers') should be subtracted from the total load in each season/load period, and that the native load subtracted should be the average of the hourly native load for each season load condition.[96]

6. Relevant Geographic Market

Final Rule

68. In Order No. 697, the Commission adopted its existing approach with respect to the default relevant geographic market, with some modifications. The Commission announced that it would continue to use a seller's balancing authority area [97] or the RTO/ISO market,[98] as applicable, as the default relevant geographic market, explaining that the use of defined default geographic markets provides the industry with as much certainty as possible while also providing parties the right to challenge the default geographic market definition and submit pertinent evidence.[99]

69. With respect to traditional (non-RTO/ISO) markets, the Commission adopted a rebuttable presumption that the seller's default relevant geographic market under both indicative screens would be the balancing authority area where the seller is physically located, and each of its neighboring first-tier balancing authority areas.[100]

[95] *Id.* P 108.

[96] *See id.* P 150 (citing 18 CFR 33.3(d)(4)(i)).

[97] Previously, the Commission had used the term "control area," but in the Final Rule it replaced that term with "balancing authority area" with regard to relevant geographic markets.

[98] An RTO/ISO must have a sufficient market structure and a single energy market with Commission-approved market monitoring and mitigation.

[99] Order No. 697 at P 235.

[100] *Id.* P 231–32.

70. With respect to RTO/ISO markets, the Commission stated that sellers located in and members of the RTO/ISO may consider the geographic region under the control of the RTO/ISO as the default relevant geographic market for purposes of completing their horizontal analyses, unless the Commission has already found the existence of a submarket. Where the Commission makes a specific finding that there is a submarket within an RTO/ISO, that submarket becomes the default relevant geographic market for sellers located within the submarket for purposes of the market power analysis (both indicative screens and DPT). In the Final Rule, the Commission concluded that sellers located in these RTO/ISO submarkets should not use the entire RTO/ISO footprints as their relevant geographic markets. The Commission explained that this policy is consistent with how it has treated such submarkets in the context of mergers; the Final Rule cited several cases to support this proposition, including *Exelon Corp.*,[101] where the Commission found that PJM-East and Northern PSEG are sub-markets within PJM Interconnection (PJM).

71. The Commission stated that it would continue to allow sellers and intervenors to present evidence on a case-by-case basis to show that some other geographic market should be considered as the relevant market in a particular case. To the extent that the Commission finds that a submarket exists within an RTO/ISO, intervenors or sellers can provide evidence to the contrary; thus, a submarket, like the other default geographic markets, is a rebuttable default geographic market.[102] The Commission explained that it will also consider arguments that a seller operates in an RTO/ISO submarket even if the Commission has not previously found that a submarket exists. Likewise, sellers and intervenors also may present evidence that the relevant market is broader than a particular balancing authority area or RTO/ISO footprint or submarket.

72. The Commission stated that sellers may incorporate the mitigation they are subject to in RTO/ISO markets or submarkets with Commission-approved market monitoring and mitigation as part of their market power analysis.[103] By way of example, if a market power analysis indicates that a seller may have market power, the seller may point to the RTO/ISO mitigation rules as evidence that its market power has been adequately mitigated. The same is true for submarkets; for instance, New York City will be treated as a separate default market for market-based rate study purposes, and its existing In-City mitigation will be used to assess whether any concerns over market power are already mitigated.[104]

[101] 112 FERC ¶ 61,011, *reh'g denied*, 113 FERC ¶ 61,299 (2005) (*Exelon*). The Commission noted that Exelon later terminated the merger. Order No. 697 at P 236 and n.220.

[102] *Id.* P 238.

[103] *Id.* P 241.

Requests for Rehearing

73. TDU Systems and NRECA object to the Commission's determination to use a balancing authority area or RTO/ISO region as a default relevant geographic market; they believe that a seller should always have the burden of defining the appropriate geographic market or submarket and that the Commission cannot lawfully place the burden on customers or intervenors to show that the "default" market is *not* the relevant geographic market.[105] Thus, NRECA argues that the Commission's determination to use the applicant public utility's balancing authority area or the RTO/ISO region as the default relevant geographic market is arbitrary, capricious, contrary to law, in excess of statutory authority, and not supported by substantial evidence.[106] Further, according to NRECA, the Final Rule did not adequately respond to NRECA's argument that default geographic markets should not be used because the Commission cannot place the burden on intervenors to demonstrate that the default market is not the relevant geographic market, and failed to satisfactorily explain the Commission's action " 'including a rational connection between the facts found and the choice made.' " [107]

74. TDU Systems state that, although the Commission has attempted to create a "balanced approach," it is arbitrary and capricious to grant market-based rate authority based on the inaccurate assumption that in most cases, the Commission will rely on RTO/ISO regions as default geographic markets. TDU Systems cite *Keystone* for the proposition that evidentiary presumptions are only permissible in the presence of a connection between

[104] *Id.* P 242.

[105] TDU Systems Rehearing Request at 15; NRECA Rehearing Request at 18.

[106] NRECA Rehearing Request at 2–3 (citing *Secretary of Labor* v. *Keystone Coal Mining Corp.*, 151 F.3d 1096, 1100 (D.C. Cir. 1998) (*Keystone*); 5 U.S.C. 556(d); 5 U.S.C. 706(2)(A), (C), (E); 16 U.S.C. 824d(e); 16 U.S.C. 825l(b); *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 FR 12265 (March 15, 2007), FERC Stats. & Regs. ¶ 31,241, at P 901–1094 (2007), *order on reh'g and clarification*, Order No. 890–A, 73 FR 2984 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261 (2007)).

[107] *Id.* at 20 (quoting *Pac. Gas & Elec. Co.* v. *FERC*, 373 F.3d 1315, 1319 (D.C. Cir. 2004)).

proven and inferred facts, and asserts that, ''[e]ven with the submarkets the Commission identifies in the Final Rule (at P 246), the exceptions to the rule are still far too numerous to declare that the proposal can pass the 'so probable that it is sensible' test.'' [108] It argues that public utility sellers should have an affirmative obligation, meeting the strict standard for burden shifting, to identify the relevant geographic market and justify the market used in their horizontal market power analyses. Using the wrong default geographic markets prevents the Commission from accurately assessing the public utility's market power and thus contravenes the statutory prerequisites.

75. NRECA and TDU Systems claim that the use of RTO/ISO regions and balancing authority areas as default relevant markets in many cases will not produce valid screen results because they do not take into account well-known binding transmission constraints and load pockets, such as those the Commission has found in the New York Independent System Operator (NYISO) and the ISO New England (ISO–NE) submarkets.[109] They assert that the Commission should eliminate the use of the seller's balancing authority area or RTO/ISO region as the relevant market and instead require an applicant to identify the relevant geographic market based on actual data including grid topology and existing transmission constraints.[110]

76. In contrast to the arguments raised on rehearing by NRECA and TDU Systems, PSEG and Reliant find fault with the Commission's ruling that the larger RTO/ISO region will not be used as the default geographic market for market-based rate sellers located in RTO/ISO areas where the Commission has found submarkets to exist. PSEG claims that the ruling departs from many years of Commission policy utilizing the RTO/ISO as the default relevant geographic market and is inconsistent with the Commission's confidence in the impact of RTO/ISO market monitoring and mitigation.[111] PSEG asserts that this major change in policy is not supported by substantial evidence, is not a product of reasoned decision making,[112] and claims that ''it is difficult to discern the legal or factual basis for the change.'' [113] Regarding the Commission's explanation that the consideration of submarkets is consistent with the Commission's merger analysis, PSEG states that ''simply because the Commission needed to examine submarket impacts in the context of an individual merger proceeding does not make that submarket appropriate as a default geographic market to be applied going forward on a generic basis for all sellers in that submarket.'' [114] PSEG argues that the focus of the market power analysis is substantively different in the two types of proceedings, and that the public was not on notice that the Commission might rely on findings from a merger proceeding to create a generic rule applicable to all parties located in the same area, thus constituting ''retroactive rulemaking.'' Moreover, PSEG contends that by basing a generic determination of submarkets on prior merger filings rather than after a systematic review of market power in a region, the Commission adopts a policy that discriminates against some market participants because a market-based rate seller can be located in an RTO/ISO sub-region that has greater instances of transmission constraints than any of the submarkets specifically identified in Order No. 697, but will still be able to proceed with a market-based rate application using the RTO/ISO as the default relevant geographic market.[115] PSEG asserts that a fairer approach would be to review potential submarkets comprehensively as part of the regional review process that will be conducted according to the schedule provided in Appendix D of the Final Rule.[116]

77. Reliant states that the record does not support the use of submarkets in indicative screens, noting that one commenter advocated use of a submarket when applying the DPT but that no commenters suggested that the indicative screens should be performed utilizing a submarket. Reliant argues that when a submarket is used within an RTO/ISO in indicative screens, the applicable default market used will be smaller than the full market within which a seller participates. Reliant claims that this is inconsistent with the design and intent of the indicative screens because identification of a submarket is unpredictable, and because a submarket identified in another potentially unrelated proceeding may be used.[117]

78. PSEG argues further that the Commission ignored record evidence proving the lack of technical and policy merit in creating submarkets when performing market power analyses submitted by the three RTO/ISOs that commented on the issue; and it claims that California ISO (CAISO), ISO–NE, and NYISO agree that there is no technical and structural need for the examination of RTO/ISO submarkets.[118] According to PSEG, the Commission's failure to meaningfully consider that evidence and to respond to it was arbitrary and capricious and not reasoned decisionmaking.[119]

79. PSEG contends that submarkets are inappropriate as default relevant geographic markets because they are largely a product of transmission constraints that periodically create short-term price differences between neighboring geographic areas. Such differences, it states, are not static and can be altered over the long term by transmission reinforcements, new generation entry, and changes in load.[120] It concludes that the unpredictable nature of those forces makes submarkets unreliable for assessing market power, and believes that the Commission should have retained the RTO/ISO as the default relevant geographic market so long as the RTO/ISO has market monitoring and

[108] TDU Systems Rehearing Request at 15.

[109] NRECA Rehearing Request at 19 (''Given that the Commission was able to find submarkets in relatively compact and contiguous regions such as [NYISO] and [ISO–NE], then the notion of using far-flung RTO/ISO regions such as the Midwest ISO and SPP as default markets is untenable''); TDU Systems Rehearing Request at 15.

[110] NRECA Rehearing Request at 20; TDU Systems Rehearing Request at 16.

[111] PSEG Rehearing Request at 2–3 (*quoting* Order No. 697 at P 290 (''We believe that a single market with Commission-approved market monitoring and mitigation and transparent prices provides added protection against a seller's ability to exercise market power * * *'')).

[112] *Id.* at 6 (citing *Moraine Pipeline Co.* v. *FERC*, 906 F.2d 5, 9 (D.C. Cir. 1990) (reasoned decision making requires that the Commission must not just acknowledge arguments made, but must ''respond to [such] arguments and * * * articulate its decision based on evidence in the record''); *Motor Vehicles Mfrs. Ass'n.* v. *State Farm Mutual Auto. Ins. Co.*, 463 U.S. 29, 43, 48, 57 (1983); *Williams Natural Gas Co.* v. *FERC*, 90 F.3d 531, 533 (D.C. Cir. 1996) (To be upheld, the Commission's order must be ''supported by substantial evidence and reached by reasoned decision-making—that is, a process demonstrating the connection between the facts found and the choice made.'')).

[113] *Id.* PSEG also cites *Missouri Public Service Commission* v. *FERC*, 234 F.3d 36, 40 (D.C. Cir. 2000) (when ''the Commission balances competing interests in arriving at its decision, it must explain on the record the policies which guide it.'').

[114] *Id.* at 6–7. *See also* Reliant Rehearing Request at 5–6, warning that sellers may have no choice but to intervene and potentially litigate in additional proceedings where the Commission may possibly make a finding that identifies a new submarket.

[115] *Id.* at 8.

[116] *Id.* at 9.

[117] Reliant Rehearing Request at 5–6.

[118] PSEG Rehearing Request at 4–6 (citing NYISO NOPR comments at 3–4; ISO–NE NOPR comments at 4 and 6; and CAISO NOPR comments at 13).

[119] *Id.* at 6 (citing *Moraine Pipeline Co.* v. *FERC*, 906 F.2d 5, 9 (D.C. Cir. 1990) (holding that the Commission must not just acknowledge arguments made but must respond to such arguments)).

[120] Reliant Rehearing Request at 7–8; PSEG Rehearing Request at 9–10. Reliant limits its objections to the use of submarkets in indicative screens.

mitigation programs in place in conjunction with a regional transmission expansion planning program.

80. With specific reference to the Commission's generic finding of submarkets in Eastern PJM and Northern PSEG, PSEG alleges that the Commission erred in relying on a prior ruling in the Exelon-PSEG merger proceeding,[121] which merger was subsequently terminated. According to PSEG, the Commission cannot rely on the Exelon-PSEG merger proceeding because that analysis was dependent on the assumption that Exelon and PSEG would merge; the termination of the merger changed key assumptions that were material to the market power analysis examining what changes to competitive conditions would occur as a consequence of the merger.

Commission Determination

81. We affirm our decision to use a balancing authority area or RTO/ISO region as a default relevant geographic market. In Order No. 697, the Commission fully explained the basis for using default geographic markets. The Commission explained that the use of defined default geographic markets provides sellers and intervenors a measure of certainty regarding the relevant market while also providing parties the right to challenge the default geographic market definition and submit pertinent evidence of an alternative geographic market based on actual data.

82. As discussed more fully below, we reject NRECA's and TDU Systems' argument that the Commission's determination to use the applicant public utility's balancing authority area or the RTO/ISO region as the default relevant geographic market is arbitrary, capricious, contrary to law, in excess of statutory authority, and not supported by substantial evidence. In Order No. 697 the Commission carefully considered and balanced various arguments on both sides of the issue concerning whether it is appropriate to use default geographic markets for purposes of the horizontal analysis.

83. Our use of the applicant public utility's balancing authority area or the RTO/ISO region as the default relevant geographic market is supported by the evidence. In particular, with regard to traditional (non-RTO/ISO) markets, the Commission adopted as the default geographic market first the balancing authority area where the seller is physically located and, second, the markets directly interconnected to the seller's balancing authority area (first-tier balancing authority area markets). Our decision to use the balancing authority area or the RTO/ISO region as the default geographic market closely tracks our guidance provided in Order No. 697 on what constitutes a market.[122] Our experience has indicated that typically there are frequently recurring physical impediments to trade between balancing authority areas that would prevent competing supplies from first-tier markets from reaching wholesale customers.[123] Thus, our decision to consider balancing authority areas as the default geographic market is neither arbitrary nor capricious but, rather, firmly embedded in the characteristics of our jurisdictional markets.

84. In addition, with regard to public policy considerations and regulatory certainty, the Commission explained in Order No. 697 that using balancing authority areas allows the Commission and the public to rely on publicly available data provided for balancing authority areas that are relevant to the market-based rate analysis.[124] Further, it is the interconnection and coordination between balancing authority areas that provides a foundation for the Commission to analyze transmission limitations and other transfers of energy and provides reasonable measures of the relevant geographic market under typical circumstances.[125]

85. With regard to RTO/ISO markets, the Commission's approach has been well considered and consistent with our approach described above regarding traditional markets. After weighing all the facts, including our experience regulating these markets, the Commission concluded that the geographic region under the control of the RTO/ISO is the appropriate market absent evidence to the contrary. Thus, as a starting point and consistent with our guidance on what constitutes a market, the Commission has made a finding that the geographic region under the control of the RTO/ISO is appropriate for use as the default geographic market. In addition, where the Commission has made a specific finding that there is a submarket within an RTO/ISO, the Commission explained that the submarket should be considered as the default relevant geographic market. Thus, our decision to consider the geographic region under the control of the RTO/ISO as the default geographic market, unless the Commission makes a specific finding of the existence of a submarket, is neither arbitrary nor capricious, but similarly embedded in the characteristics of our jurisdictional markets.

86. With regard to TDU Systems' and NRECA's assertion that a seller should always have the burden of defining the appropriate geographic market or submarket and that the Commission cannot lawfully place the burden on customers or intervenors to show that the ''default'' market is not the relevant geographic market, we disagree. As stated above, after careful consideration and based on the facts before us, the Commission has made findings regarding these geographic markets. We reject TDU Systems' and NRECA's argument that under *Keystone*, the Commission may not grant market-based rate authority based on the assumption that, in most cases, the Commission will rely on RTO/ISO regions as default geographic markets because such a presumption shifts the burden of establishing the relevant geographic market from the seller to intervenors. In *Keystone*, the court found that an evidentiary presumption is only permissible if there is ''a sound and rational connection between the proved and inferred facts.''[126] Contrary to TDU Systems' and NRECA's argument that there is no evidence to support use of RTO/ISO regions as default geographic markets, and, as explained in the Final Rule, the RTO/ISO regions have historically been used as default geographic markets.[127] As

[121] PSEG Rehearing Request at 10, referring to *Exelon Corp.*, 112 FERC ¶ 61,011, *order on reh'g*, 113 FERC ¶ 61,299 (2005).

[122] Order No. 697 at P 231–232.

[123] *Id.* P 268.

[124] *Id.* P 233.

[125] *Id.* P 251. Similar to a control area, a balancing authority area is physically defined with metered boundaries that we refer to as the balancing authority area. Every generator, transmission facility, and end-use customer must be in a balancing authority area. The responsibilities of a balancing authority include the following: (1) *Match*, at all times, the power output of the generators within the balancing authority area and capacity and energy purchased from or sold to entities outside the balancing authority area, with the load within the balancing authority area in compliance with the Reliability Standards; (2) maintain scheduled interchange and control the impact of interchange ramping rates with other balancing authority areas, in compliance with Reliability Standards; (3) have available sufficient generating capacity, and Demand Side Management to maintain Contingency Reserves in compliance with Reliability Standards; and (4) have available sufficient generating capacity, Demand Side Management, and frequency response to maintain Regulating Reserves and Operating Reserves in compliance with Reliability Standards. *Id.* (citing Approved Reliability Standards. *http://www.ferc.gov/industries/electric/indus-act/reliability/standards.asp*).

[126] *Keystone*, 151 F.3d 1096 at 1100.

[127] *See* April 14 Order at P 41, 187 (stating that when performing the generation market power analysis, applicants located in RTOs/ISOs with sufficient market structure may consider the geographic region under the control of the RTO/ISO

Continued

explained in the Final Rule and prior orders, we have used RTO/ISO regions as the default market for many reasons, including the central commitment and dispatch in most RTOs/ISOs, the elimination of trade barriers within those regions (e.g., pancaked rates), common market mitigation and other factors.[128] On rehearing, TDU Systems and NRECA have presented no empirical evidence demonstrating that RTO/ISO regions should not be used as default geographic markets, or that the use of RTO/ISO regions as default geographic markets is inadequate or insufficient for the typical situation.

87. We agree with NRECA and TDU Systems that we should take into account binding transmission constraints and load pockets in both RTO/ISO regions and balancing authority areas and Order 697 does so. Based on our findings on binding transmission constraints, the Commission has identified six submarkets in NYISO, PJM, and ISO–NE, as described in Order No. 697.[129] Where the Commission has made a specific finding that there is a submarket within an RTO/ISO or within any other market, the market-based rate analysis (both the indicative screens and the DPT) should consider that submarket as the default relevant geographic market.[130] We note that NRECA and TDU Systems' argument that the use of RTO/ISO regions and balancing authority areas as the default relevant market in many cases will not produce valid screen results because this use does not take into account ''well-known binding transmission constraints and load pockets'' is overly simplistic. The Commission has provided in Order No. 697 [131] guidance as to the record information needed to make a determination that an alternative geographic market is appropriate (e.g., expanded market, submarket). The Commission will, and has,[132] carefully considered record evidence regarding geographic markets. In particular, ''well-known'' is an arbitrary term and does not meet the type of evidence needed for the Commission to base a determination. Accordingly, we will continue to use a seller's balancing authority area or the RTO/ISO market, as applicable, as the default relevant geographic market, unless the Commission makes a specific finding of the existence of a submarket.

88. We disagree with PSEG's statement that, ''simply because the Commission needed to examine submarket impacts in the context of an individual merger proceeding does not make that submarket appropriate as a default geographic market to be applied going forward on a generic basis for all sellers in that submarket.'' As discussed above, our determination of what constitutes a geographic market is not dependent upon whether the type of proposal before us is in the context of a market-based rate or merger proceeding. Rather, we base our determination on facts relating to a particular region and the guidelines we have provided regarding what constitutes a geographic market. Whether in a merger proceeding, RTO proceeding, or market-based rate proceeding the fundamental characteristics of a market does not change nor should we ignore our findings because administratively they were made in a different proceeding.

89. With regard to PSEG's argument that the public was not on notice that the Commission might rely on findings from a merger proceeding that could apply in subsequent market-based rate proceedings, we reiterate that, to the extent that the Commission finds that a submarket exists within an RTO/ISO, intervenors or sellers can provide evidence to the contrary (*i.e.*, the submarket, like our other default geographic markets, is rebuttable).[133] Moreover, in the NOPR in this proceeding, the Commission explained that its experience with corporate mergers and acquisitions indicates that the RTO/ISOs that the Commission has identified as meeting the criteria for being considered a single market for purposes of performing the generation market power screens have, at times, been divided into smaller submarkets for study purposes because frequently binding transmission constraints prevent some potential suppliers from selling into the destination market. Therefore, the Commission sought comment on its approach under the market-based rate program of considering the entire geographic region under control of the RTO/ISO, with a sufficient market structure and a single energy market, as the default relevant market. Further, the NOPR asked whether the Commission should continue its approach of considering the entire geographic region as the default market for purposes of the indicative screens but consider RTO/ISO submarkets for purposes of the DPT.[134] Thus, contrary to PSEG's argument, since the issuance of the NOPR in May 2006, the public has been on notice that the Commission might rely on findings from a merger proceeding that could apply in determining RTO/ISO submarkets that may be used in market-based rate proceedings.

90. However, we will grant PSEG's request for rehearing regarding the Commission's determination in the Final Rule that because the Commission made a prior finding in the Exelon-PSEG merger proceeding that Northern PSEG is a separate market in PJM, sellers in PJM should use that submarket as the default geographic market for their market-based rate analysis. After the parties in that case terminated the merger, the U.S. Court of Appeals for the D.C. Circuit vacated the Commission's orders on procedural grounds. In light of the ultimate disposition of Exelon/PSEG merger proceeding, on reconsideration, we conclude that we erred in relying on a prior finding of submarkets that was made in that proceeding.[135]

91. With regard to PJM East, however, we note that in proceedings other than the Exelon/PSEG merger, the

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as the relevant default geographic region for purposes of completing their analyses, and comparing the practice to the Commission's earlier approach under the hub and spoke analysis).

[128] *See*, *e.g.*, April 14 Order at P 187–191; July 8 Order at P 177; *Mystic I, LLC*, 111 FERC ¶ 61,378, at P 14–19 (2005) (rejecting challenge to the use of ISO–NE market as the relevant geographic market on the basis that local market power mitigation is in place: ''[W]ithout specific evidence to the contrary, we are satisfied that ISO–NE has Commission-approved tariff provisions in place to address instances where transmission constraints would otherwise allow generators to exercise local market power and that these rules and procedures will apply in the NEMA/Boston zone within ISO–NE.''); *Wisconsin Electric Power Co.*, 110 FERC ¶ 61,340, at P 19–20, *reh'g denied*, 111 FERC ¶ 61,361, at P 13–15 (2005) (rejecting challenge to use of Midwest ISO market as the relevant geographic market on basis that local market power mitigation measures exist: ''The tighter thresholds in NCAs such as WUMS in the Midwest ISO, and the resulting tighter mitigation of bids, are local market power mitigation measures'' and should adequately address specific concerns regarding the possibility that Wisconsin Electric can exercise market power in the WUMS region). *Accord AEP Power Marketing, Inc.*, 109 FERC ¶ 61,276 (2004), *reh'g denied*, 112 FERC ¶ 61,320, at P 23–25 (2005), *aff'd*, *Industrial Energy Users-Ohio* v. *FERC*, No. 05–1435 (D.C. Cir. Feb. 16, 2007) (use of PJM footprint as relevant geographic market; noting existence of Commission-approved market monitoring and mitigation). *See also Midwest Independent Transmission System Operator, Inc.*, 109 FERC ¶ 61,157, at P 463 (2004) (noting that the Midwest ISO-wide market will not be considered as the default geographic market until such time as the Midwest ISO becomes a single market and performs functions such as single central commitment and dispatch with Commission-approved market monitoring and mitigation).

[129] *Id.* P 236.

[130] *Id.*

[131] *Id.* P 267–278.

[132] *See Pinnacle West Capital Corp.*, 122 FERC ¶ 61,035 (2008).

[133] Order No. 697 at P 238.

[134] NOPR at P 61; Order No. 697 at P 215.

[135] *Exelon Corp.*, 112 FERC ¶ 61,011, *reh'g denied*, 113 FERC ¶ 61,299 (2005), *vacated*, *PPL Electric Utilities Corp.* v. *FERC, No. 06–1009 (D.C. Cir. Dec. 21, 2006).*

Commission also treated PJM-East as a market within PJM.[136] Accordingly, we reaffirm our finding in the Final Rule that because the Commission already has found that PJM-East constitutes a separate market in PJM, sellers located in PJM should use PJM-East as the default geographic market.

92. We reject PSEG's argument that the Commission's policy discriminates against some market participants. In particular, PSEG contends that a market-based rate seller can be located in an RTO/ISO sub-region that has greater instances of transmission constraints than any of the submarkets specified in the Final Rule, but will be able to proceed with a market-based rate application using the RTO/ISO as the default relevant market. As the Commission has stated, default geographic markets are adequate and sufficient for the typical situation, and by defining default geographic markets, we provide the industry as much certainty as possible while also providing affected parties the right to challenge the default geographic market definition and provide evidence in that regard.[137] Thus, in the example posited by PSEG, if there is evidence that indicates high instances of transmission constraints within an RTO that has not been previously found to constitute a submarket, intervenors have the opportunity to present that evidence to the Commission. Accordingly, because all market participants have the opportunity to challenge the default geographic market definition, this policy does not discriminate against some market participants. Rather, the Commission's policy in this regard recognizes the findings the Commission has already made and Order No. 697 provides guidance to parties that wish to challenge the default geographic markets.

93. With regard to PSEG's claims that the Commission failed to consider evidence submitted by CAISO, ISO-NE, and NYISO that there is no technical and structural need for the examination of RTO/ISO submarkets, we find that where the Commission has made a specific finding that there is a submarket within an RTO/ISO, the market-based rate analysis should reflect the facts and consider that submarket as the default relevant geographic market. To do otherwise would be inconsistent with our findings of a submarket in the first instance. In particular, the Commission has consistently stated that the Commission-approved market monitoring and mitigation provides added protection against a seller's ability to exercise market power, but cannot replace the generation market power analysis.[138] While we consider carefully comments by interveners, this Commission will also consider all the facts before us before making a finding.

94. In addition, while PSEG is correct that transmission constraints can be temporary, as noted above, all of the submarkets that the Commission has identified result from frequently binding transmission constraints during historical seasonal peaks examined; these particular constraints have not tended to be temporary in nature. Evidence with respect to whether a transmission constraint is temporary or is frequently binding will be considered in determining whether a submarket exists. To the extent that some existing constraints may be alleviated by construction of new transmission facilities, parties may bring these situations to our attention for further consideration.

95. Without a correctly defined submarket, sellers with market power in the RTO/ISO market may not be identified, and their market power mitigated in both the real-time and day-ahead markets. While we acknowledge PSEG's claim that the Commission's determination on RTO/ISO submarkets departs from Commission policy utilizing the RTO/ISO as the default relevant geographic market, we disagree with PSEG's claim that this is inconsistent with Commission confidence in the impact of RTO/ISO market monitoring and mitigation. The purpose of this rulemaking proceeding has been to consider and evaluate the Commission's current market-based rate policy and to make adjustments to this approach, as warranted. Thus, we have carefully considered the facts before us, including our historical approach, and found it reasonable that where the Commission has made a specific finding that there is a submarket within an RTO/ISO, the market-based rate analysis should reflect those facts and consider that submarket as the default relevant geographic market because to do otherwise would be inconsistent with our findings of a submarket in the first instance. In addition, the Commission has been in the process of developing and improving policies that best protect customers and promote market competition in a manner that accounts for the changing nature of developing electricity markets. We will not depart from this basic approach.

96. Moreover, PSEG overstates the difference between our prior policy and the policy adopted in Order No. 697. Prior to Order No. 697, the Commission did not identify submarkets within an RTO/ISO as default geographic markets, but one of the principal reasons for this policy was the ability to rely on Commission-approved mitigation in submarkets within RTOs/ISOs to mitigate any localized market power. Although Order No. 697 changed our approach to geographic market definition as it relates to submarkets, applicants may propose to continue to rely on Commission-approved mitigation in these submarkets as adequate to address any market concerns.

RTO/ISO Exemption

Final Rule

97. Prior to the April 14 Order, the Commission exempted sellers located in markets with Commission-approved market monitoring and mitigation from providing generation market power analyses stating that such sellers will be governed by the specific thresholds and mitigation provisions approved for the particular markets.[139] In the April 14 Order, the Commission determined that it would no longer exempt these sellers, on the basis that requiring sellers located in such markets to submit screen analyses provided an additional check on the potential for market power. In Order No. 697, the Commission declined the request by commenters that it reinstate the pre-April 14 Order exemption for sellers located in markets with Commission-approved market monitoring and mitigation from providing generation market power analyses. Instead, the Commission indicated that it would continue to require generation market power analyses from all sellers, including those in RTO/ISO markets. The Commission noted that while a single market with Commission-approved market monitoring and mitigation and transparent prices provides added protection against a seller's ability to exercise market power, it cannot replace the generation market power analysis.[140]

Requests for Rehearing

98. Reliant and PSEG argue that the Commission should reconsider its decision not to exempt sellers located in markets with Commission-approved

[136] *See,* e.g., *El Paso Energy Corporation,* 92 FERC ¶ 61,076 (2000), *Energy East Corporation*, 96 FERC ¶ 61,322 (2001), *Potomac Electric Power Company,* 96 FERC ¶ 61,323 (2001).

[137] *Id.* P 234.

[138] *See* Order No. 697 at P 290.

[139] *See AEP Power Marketing, Inc.,* 97 FERC ¶ 61,219 (2001).

[140] *Id.* P 290.

market monitoring and mitigation from submitting horizontal market power analyses. Reliant contends that the Commission did not explain what value a separate horizontal market power analysis would have, given that market monitoring by an independent market monitor consistent with Commission-approved rules and mitigation already identifies and mitigates market power. According to Reliant, market monitoring and mitigation provides a better picture of market power issues in RTO/ISO markets as compared to an individual seller's separate horizontal market power analysis which considers only market power at a fixed moment in time and also provides relief from the costs and burdens of producing a horizontal market power analysis.[141] In the alternative, if the Commission declines to reinstate the exemption, Reliant asserts that the Commission should clarify that Commission-approved mitigation rules presumptively mitigate a seller's market power and, in addition, the Commission should reconsider its decision to utilize previously identified RTO/ISO submarkets as the relevant geographic market for the indicative screens.

99. Reliant opines that a fundamental purpose and objective of market monitoring and mitigation is to detect actual, and the potential for, market power and to safeguard against it so as to ensure that no seller in the market can dominate the market, manipulate price, or otherwise act to stifle competition.[142] Accordingly, Reliant argues that a presumption that a seller's market power is adequately mitigated where Commission-approved market monitoring and mitigation rules are in effect is entirely appropriate, unless an intervenor can demonstrate why Commission-approved mitigation is insufficient in a particular case. According to Reliant, it is not appropriate to add the administrative burden of applying indicative screens if the Commission believes that market monitoring and mitigation is generally working.[143]

100. PSEG asserts that the Commission erred in failing to create a presumption that, even when the Commission has found submarkets to exist, no further analysis of the submarkets is required so long as a robust RTO/ISO market monitoring and mitigation scheme is in place. According to PSEG, a demonstration of a lack of market power in submarkets should only be required if there is reason to question whether such local market power is being addressed. RTO/ISO markets with Commission-approved market monitoring and mitigation programs in place should have a presumption that analysis of potential submarkets is not required. PSEG states that, to the extent other market participants believe otherwise, the burden should fall on them to show that an analysis of these submarkets was in fact required.[144]

101. To further support its position, PSEG notes that none of the three RTO/ISOs that filed comments on the NOPR saw any reason for applying mitigation outside of their existing programs. PSEG states that not accepting the efficacy of the RTO/ISO mitigation for purposes of the market-based rate assessment potentially undermines the authority and role of the RTO/ISOs.[145] PSEG suggests that the Advanced Notice of Proposed Rulemaking on organized markets would be a preferable way for the Commission to fine-tune the market monitoring and mitigation functions of such organizations on a prospective basis.[146]

102. Similarly, EEI requests that the Commission clarify that ''mitigated sellers in RTOs and ISOs may rely on Commission-approved market monitoring and mitigation for sales within the RTOs and ISOs without each seller having to demonstrate that such mitigation suffices in place of the default mitigation, unless a complainant demonstrates that the RTO and ISO monitoring and mitigation does not suffice as to a particular seller.'' [147] EEI is concerned that the Commission may unnecessarily burden sellers in the organized markets with having to demonstrate in each individual proceeding that the RTO/ISO mitigation measures suffice as an alternative to Order No. 697's default mitigation.

103. NRG believes that Order No. 697 creates ambiguity regarding how the Commission's default market power mitigation regime will interact with existing mitigation regimes that have been approved in organized RTO/ISO markets. NRG asserts that this ambiguity will discourage suppliers from building new generation in constrained areas. Thus, NRG seeks clarification, and, alternatively, rehearing, on two points. First, NRG asks that the Commission clarify that it will rebuttably presume that existing RTO/ISO regimes adequately mitigate market power for any sellers located in an RTO/ISO market that fail to pass indicative screens and a DPT analysis.[148] Second, in the event that a seller's market power is found not to be adequately mitigated, the Commission should clarify that the seller is allowed to propose its own tailored mitigation measures not necessarily based on embedded costs.[149]

104. On the first point, NRG explains that the Final Rule does not explicitly state that RTO/ISO monitoring and mitigation protocols will provide sufficient mitigation for any market power presumed if a seller fails the screens. NRG asserts that any generation market power a seller might possess has already been mitigated by those protocols. Thus, such sellers should not automatically be treated the same way as other mitigated sellers and subjected to default mitigation. However, NRG contends that the Final Rule leaves in question whether existing RTO/ISO mitigation regimes or the conflicting mitigation regime adopted in the Final Rule will govern in future seller-specific cases. NRG warns that this regulatory uncertainty will put new investment at risk, an outcome that should be avoided given the great efforts made to put in place alternatives to RMR contracts.[150] In addition, NRG claims that the ambiguity threatens to harm state-sanctioned competitive procurement programs, which typically require binding bids which cannot be conditioned on obtaining subsequent Commission approval.[151]

105. Regarding the second requested clarification, NRG notes that in several places in the Final Rule, the Commission states that it will retain existing cost-based default mitigation rates, but is unclear whether alternative, tailored mitigation rates must be cost-

[141] Reliant Rehearing Request at 2–3.

[142] *Id.* at 3 (citing *Market Monitoring Units in Regional Transmission Organizations and Independent System Operators,* 111 FERC ¶ 61,267, at P 1 (2005) (market monitoring units perform an important role in enhancing competitiveness of RTO/ISO markets by, among other things, monitoring organized wholesale markets to identify potential anticompetitive behavior by market participants and providing comprehensive market analysis critical for informed policy decision making); April 14 Order, 107 FERC ¶ 61,018 at P 186, 190 (recognizing the pro-competitive benefits of RTO/ISO markets with market monitoring and mitigation)).

[143] *Id.* at 7.

[144] PSEG Rehearing Request at 11–12.

[145] *Id.*

[146] *Id.* at 12 (citing *Wholesale Competition in Regions with Organized Electric Markets, Advanced Notice of Proposed Rulemaking,* 72 FR 36276 (July 2, 2007), FERC Stats. & Regs. ¶ 32,617 (2007) (considering potential reforms to attributes of organized markets, including market monitoring).

[147] EEI Rehearing Request at 4–5.

[148] NRG Rehearing Request at 2.

[149] *Id.* at 3.

[150] *Id.* at 7 (citing *Devon Power LLC,* 115 FERC ¶ 61,340 (2006) (concerning the New England FCM settlement) and *PJM Interconnection, L.L.C.,* 117 FERC ¶ 61,331 (2006) (concerning the PJM RPM settlement)).

[151] *Id.* at 10–12.

based. NRG seeks clarification that the apparent limitation to cost-based alternatives was inadvertent. In addition, NRG states that ''the Commission should make clear that in reviewing alternative mitigation measures proposed by merchant generators in RTOs, it will consider whether the proposed measures will support and attract necessary investment on reasonable terms, and recover the supplier's cost of capital.'' [152]

106. NYISO states that it is unclear whether the Commission intended to adopt a default mitigation measure that would be inconsistent with its previously approved market design and mitigation measures for the NYISO's bid-based, uniform clearing-price auction markets.[153] In particular, NYISO argues that there is no evidentiary or policy basis that would justify the imposition of default mitigation in the form of a revenue cap, rather than a bid cap, in Commission-approved Locational Based Marginal Price markets like NYISO.[154]

107. NYISO argues that the imposition of default market power mitigation in the form of revenue caps rather than bid caps would be incompatible with the principles underlying uniform clearing price auctions. NYISO ensures that the market clearing price will either be a competitive price or it will be a mitigated price.[155] Thus, NYISO requests clarification that cost-based mitigation will limit a mitigated entity's permissible maximum bid, but not constrain the mitigated entity from receiving the market clearing price if it is not the marginal seller. Additionally, NYISO argues that if the Commission's default cost-based mitigation is interpreted to impose a revenue cap as well as a bid cap, the NYISO states that it will face significant administrative burdens if revenue caps are imposed rather than bid caps.[156]

108. APPA/TAPS, on the other hand, believe that the Commission should clarify that a seller relying on RTO/ISO mitigation to remedy its market power must demonstrate those measures' effectiveness. APPA/TAPS note that the Final Rule indicates sellers can incorporate existing RTO/ISO mitigation as part of their market power analyses, but asks for clarification that an applicant must make a specific showing that those mitigation measures in fact address the specific concerns in the market-based rate analysis. APPA/TAPS assert that the scope of RTO/ISO mitigation is much narrower than the default, cost-based mitigation the Commission prescribes; it notes that the Commission has stated that RTO/ISO mitigation and the market-based rate analysis are different and that'' 'pieces of one should not automatically be used as precedent for the other.' '' [157] APPA/TAPS state that RTO/ISO mitigation measures apply only to spot markets and day-ahead and/or real time, but do not apply to weekly, monthly or long-term transactions, including those negotiated on a bilateral basis, and that RTO/ISO mitigation is often far less protective than the Commission's cost-based default of incremental cost plus 10 percent. APPA/TAPS explain that they are not asking the Commission to make a generic finding that all RTO/ISO mitigation is insufficient to mitigate sellers' generation market power, but that they seek a ruling that the burden of proof that the RTO/ISO mitigation adequately addresses the seller's market power falls on the seller, rather than intervenors. If the Commission does not make that clarification, APPA/TAPS state that it should clarify that it will allow intervenors to challenge such claims and will give meaningful consideration to those challenges.[158]

Commission Determination

109. The Commission denies the requests of PSEG and Reliant to reconsider its decision to require sellers located in markets with Commission-approved market monitoring and mitigation to submit horizontal market power analyses. As we explained in Order No. 697, while the Commission-approved market monitoring and mitigation in RTO/ISO markets provides protection against a seller's ability to exercise market power, it cannot replace the horizontal market power analyses which provide the Commission and the industry with critical information regarding the potential market power of sellers in the market.

110. We conclude that the dual protections of individual market power analyses and mitigation rules of the RTO/ISOs provide the Commission with better ability to discern and protect against potential market power. While, as discussed below, mitigation rules for the individual RTO/ISOs in most cases should be sufficient to guard against the exercises of market power, we are not comfortable at this time with dispensing of the requirement for sellers in RTO/ISOs to provide us with horizontal market power analyses. Any administrative burden of submitting such analyses is outweighed by the additional information gleaned with respect to a specific seller's market power.

111. APPA/TAPS request that the Commission clarify on rehearing that a seller relying on RTO/ISO mitigation to mitigate its market power must demonstrate the effectiveness of those measures. A number of other petitioners, on the other hand, request that the Commission clarify that it will rebuttably presume that existing RTO/ISO regimes adequately mitigate market power for any sellers located in an RTO/ISO market that fail the indicative screens and the DPT analysis. In response to these requests, to the extent a seller seeking to obtain or retain market-based rate authority is relying on existing Commission-approved RTO/ISO market monitoring and mitigation, we adopt a rebuttable presumption that the existing mitigation is sufficient to address any market power concerns. However, intervenors may challenge the effectiveness of that mitigation. We agree with PSEG that the challenging party should have the burden of proof to demonstrate that existing RTO/ISO mitigation is not sufficient. Thus, because existing RTO/ISO mitigation has been found to be just and reasonable by the Commission in the context of a proceeding specific to a particular RTO/ISO and involving all of its stakeholders, we believe it appropriate and clarify herein that there is a rebuttable presumption that such RTO/ISO mitigation is adequate to mitigate market power in the RTO/ISO market, including Commission-approved mitigation applicable to RTO/ISO submarkets such as In-City New York. To the extent that a party wishes to challenge that presumption, the challenging party will have the burden of proof.

[152] *Id.* at 16.

[153] NYISO Rehearing Request at 4 (citing *New York Independent System Operator, Inc.,* 89 FERC ¶ 61,196 (1999), *order on compliance and reh'g,* 90 FERC ¶ 61,317, *clarified,* 91 FERC ¶ 61,154 (2000) (orders addressing the NYISO's proposed Market Mitigation Measures); *New York Independent System Operator, Inc., et al.,* 99 FERC ¶ 61,246 (2002) (order on the NYISO's comprehensive mitigation measures filing); *Midwest Independent Transmission System Operator, Inc.,* 108 FERC ¶ 61,163, at P 257, *order on reh'g,* 109 FERC ¶ 61,157 (2004) (''We find that the conduct and impact approach with its associated thresholds is an appropriate approach to mitigation in the Midwest ISO's market. The conduct and impact approach allows for a lighter handed approach to mitigation, in which the market is allowed to function as is, except when problems are detected.'')).

[154] *Id.* at 7.

[155] *Id.* at 2, 3, 5.

[156] *Id.* at 7.

[157] APPA/TAPS Rehearing Request at 24 (citing *Midwest Independent Transmission System Operator, Inc.,* 109 FERC ¶ 61,157, at P 242 (2004), *order on reh'g,* 111 FERC ¶ 61,043 (2005)).

[158] *Id.* at 26–27.

112. In response to EEI, to the extent the Commission has considered a challenge to existing mitigation and has found it to be adequate, any additional challenges must demonstrate a change in circumstances rather than just rearguing issues on which the Commission has already ruled.

113. A number of petitioners raise issues regarding the types of mitigation that the Commission might impose on mitigated sellers in RTOs/ISOs. NRG requests that, in the event a seller's market power is found not to be adequately mitigated, the Commission should clarify that the seller may propose tailored mitigation measures that are not necessarily based on embedded costs. NYISO states that it is unclear whether the Commission intended to adopt a default mitigation measure for any sellers located in an RTO/ISO market that fail to pass the indicative screens and the DPT analysis and seeks clarification that cost-based mitigation will only limit a mitigated entity's permissible maximum bid, but will not constrain the mitigated entity from receiving the market clearing price if it is not the marginal seller.

114. In response to these issues raised regarding the types of mitigation that the Commission might impose on mitigated sellers in RTO/ISO, the Commission will, depending on the nature of the evidence submitted by an intervenor, consider whether to institute a separate section 206 proceeding that would be open to all interested entities to investigate whether the existing RTO/ISO mitigation continues to be just and reasonable and, if not, how such mitigation should be revised. Any intervenor in such a section 206 proceeding may present evidence on the adequacy of the existing mitigation. If appropriate, the Commission will consider modifying that mitigation on an RTO/ISO-wide basis, rather than on a seller-specific basis, because RTO/ISO mitigation is designed to mitigate market power generally. In other words, if existing mitigation is found to be inadequate for a particular seller, then it is likely to be insufficient for all similarly situated sellers. We note that in reviewing alternative mitigation measures in the context of RTOs, the Commission will consider whether the proposed mitigation measures will adequately deter the exercise of market power, are consistent with the RTO/ISO's market design and will support and attract necessary investment on reasonable terms, and recover the suppliers' cost of capital. With regard to NYISO's request, as discussed above, with regard to sellers located in an RTO/ISO market that fail to pass the indicative screens and the DPT analysis, we will not impose default cost-based rate mitigation (which is used in non-RTO/ISO markets) in addition to RTO/ISO mitigation. Rather, we adopt a rebuttable presumption that the existing mitigation is sufficient to address any market power concerns.

115. With regard to APPA/TAPS' assertion that the scope of RTO/ISO mitigation is much narrower than the default cost-based rate mitigation and its argument that RTO/ISO mitigation provides less protection than the Commission's default mitigation of incremental cost plus 10 percent, we understand that RTO/ISO mitigation measures apply to day-ahead and/or real-time markets, and we reiterate that RTO/ISO mitigation is determined to be just and reasonable when it is approved by the Commission.[159] We review and approve mitigation rules in RTO/ISO markets on the basis of the specific facts and circumstances prevailing in such markets. Thus, customers and other interested parties are fully able, in the context of those proceedings, to comment on whether the mitigation rules are sufficiently strong to deter the exercise of market power. In addition, pursuant to the Final Rule, customers or other affected parties may argue, in the context of a specific market-based rate application or triennial review, that changed circumstances have rendered such mitigation no longer just, reasonable and not unduly discriminatory.

7. Use of Historical Data

Final Rule

116. The Commission held in the Final Rule that it would retain the ''snapshot in time'' approach for the indicative screens and the DPT, so that sellers will be required to use actual historical data for the previous calendar year in their market power analyses. After careful consideration of the comments received, the Commission chose not to adopt the NOPR proposal that the DPT analysis allow sellers and intervenors to account for changes in the market that are known and measurable at the time of filing. Instead, the Commission decided to retain its existing practice that sellers are required to use unadjusted historical data in the preparation of a DPT for a market-based rate analysis and clarified that it would require the use of the actual historical data for the previous calendar year.

117. The Commission distinguished this treatment from the approach in the Commission's merger analysis, which requires applicants and intervenors to account for changes in the market that are known and measurable at the time of filing. The Commission found that the purpose of using the DPT in market-based rate proceedings is different from that in a merger analysis. Whereas a merger analysis is forward-looking and it is difficult and costly to undo a merger, the market-based rate analysis is a ''snapshot in time'' approach where the Commission's focus is on whether the seller passes the indicative screens and the DPT based on unadjusted historical data. The Commission considered that its grant of market-based rate authority is conditioned on, among other things, the seller's obligation to inform the Commission of any change in status from the circumstances the Commission relied on in granting it market-based rate authority on an ongoing basis. Thus, the change in status reporting requirement allows the Commission to evaluate changes when they actually happen rather than relying on projections, making it unnecessary and redundant for the Commission to allow sellers to account for known and measurable changes in the DPT.

Requests for Rehearing

118. Montana Counsel argues that the Commission erred in refusing to allow adjustments to the DPT analysis to account for known and measurable future changes, such as contracts for the sale of capacity belonging to the seller that will expire during the term of its market-based rate authority. Montana Counsel asserts that by refusing to consider known and measurable changes, the Commission is intentionally allowing the DPT analysis to be conducted based on data and assumptions that are known not to be representative of reality.[160] Montana Counsel argues that it is inherently irrational, arbitrary, and capricious to allow companies whose generation market power is being analyzed to deduct the generation that is being tested from its supply on grounds that the generation is committed, as the Commission does when the contracts for power from that generation are expiring. Montana Counsel states that such a market power test is inherently flawed, and that this flawed test has concrete

[159] APPA/TAPS rely on *Midwest Independent Transmission System Operator, Inc.*, 109 FERC ¶ 61,157, at P 242 (2004), *order on reh'g*, 111 FERC ¶ 61,043 (2005) (Midwest ISO) in arguing that RTO mitigation and the market-based rate analysis are different. We recognize that in Midwest ISO the Commission stated that its market-based rate analysis and mitigation in the Midwest ISO differ, and, as stated above, we reiterate that RTO mitigation is determined to be just and reasonable when it is approved by the Commission.

[160] Montana Counsel Rehearing Request at 7.

results, with negative impacts for consumers. Montana Counsel cites the Commission's May 2006 renewal of PPL Montana's market-based rate authority, in spite of the fact that the main utility in Montana, NorthWestern Energy, must buy from PPL Montana to serve its load, as an example of the negative impact that the market power test can have on consumers.[161]

119. Montana Counsel notes that the Final Rule distinguishes the market-based rate process from the Commission's merger analysis by saying that while mergers are difficult to undo, sellers with market-based rate authority must file change in status reports, allowing the Commission to evaluate changes when they happen. Montana Counsel argues that the Commission misses the point that if the change in status is caused by the expiration of a long-term contract for the sale of capacity, then by the time the change in status report is submitted, the seller may have already re-sold the capacity at a price reflecting the seller's underlying market power.[162]

120. Montana Counsel contends that the refusal to consider known and measurable changes is especially inappropriate in light of the fact that the Commission considers mitigation proposed by the seller.[163] Montana Counsel argues that, if the Commission will consider an applicant's "'propos[al] to transfer operational control of enough generation to a third party such that the applicant would satisfy [the Commission's] generation market power concerns'" it should also consider whether an applicant's available capacity will increase during the market-based rate authorization period when contracts expire.[164]

121. NRECA similarly asserts that the Final Rule's failure to require applicants and allow intervenors to incorporate known and measurable changes to historical data in the indicative screens and the DPT in favor of a rigid "snapshot" analysis of historical data is arbitrary, capricious, contrary to law, and in excess of statutory authority.[165] NRECA argues that, if the Commission knows a change will take place, it would be arbitrary and capricious to grant market-based rate authority based on an assumption that the change will not take place.[166] Long-term contracts will expire on a known schedule, and the seller should not be allowed to assume that the capacity will remain committed to the buyer. According to NRECA, the Commission cannot, consistent with the FPA, ignore that pending change in circumstances. At a minimum, intervenors should have the opportunity to demonstrate the applicant's market power using data reflecting conditions after the contracts expire.[167]

122. NRECA states that the Commission's reliance on change in status filings as the means to report the expiration of a long-term contract is illogical and does not constitute reasoned decision making.[168] NRECA believes that absent a full market power analysis, it is impossible to adequately determine the effect of the change. NRECA submits that the triennial review will often come too late to protect customers.[169]

123. TDU Systems also argue that the Commission should require applicants' market-power analyses to reflect imminent changes which are known and measurable. They agree that historical data are more objective, but object that when they are not representative of market conditions that will exist during the three-year period of market-based rate authority, considering imminent changes is legally required.[170] For soon-to-expire long-term contracts, TDU Systems assert that the seller should not be permitted to assume that the capacity will remain committed to the buyer. The burden should not be shifted to the intervenors to propose the adjustment; rather, an applicant should be required to include it as part of the analysis.[171]

Commission Determination

124. We will continue the use of historical data for both the indicative screens and the DPT in market-based rate cases. We reject several petitioners' requests that the Commission require sellers to reflect imminent changes that are known and measurable, and therefore we deny rehearing on this issue. Regarding the Commission's reliance upon historical rather than projected data in analyzing market power studies, and its determination not to require sellers to reflect changes that are known and measurable, the Commission's practice for many years has been to use a "snapshot in time approach" based on the most recently available historical data at the time of filing, *i.e.*, to rely upon studies based on unadjusted historical data. We continue to allow intervenors to submit sensitivity analyses including projected data, but we reject the proposal that applicants include adjustments to historical data as part of the required analyses.

125. There are several reasons why this approach benefits customers and is otherwise in the public interest. First, as we explained in the Final Rule, historical data are more objective, readily available, and less subject to manipulation by applicants than future projections.[172] If the Commission were to allow applicants to submit studies based on their future projections or that reflect "imminent changes," then sellers would be able to selectively "cherry pick" those changes that benefited the seller in obtaining market-based rate authorization while ignoring other equally likely future changes that would undermine the seller's chances for obtaining such authorization. Second, this approach benefits customers, state commissions and other affected intervenors because it requires the use of a consistent methodology that can be replicated by intervenors, rather than allowing sellers to submit customized market power studies that, due to myriad selective adjustments, are difficult to analyze and can hide the presence of market power. Third, it is important to note that the "snapshot in time" approach does not preclude the Commission from considering future changes in market conditions; rather, the Commission's grant of market-based rate authority is conditioned, among other things, on the seller's obligation to inform the Commission of any change in status from the circumstances the Commission relied upon in granting it market-based rate authority.

[161] *Id.* at 7–8 (citing *PPL Montana, LLC*, 115 FERC ¶ 61,204 (2006) (*PPL Montana*)). Montana Counsel includes its request for rehearing of *PPL Montana*, filed June 16, 2006 in Docket No. EL05–124, *et al.*, as Attachment A to its request for rehearing of Order No. 697. *Id.* at 8. The Montana Counsel's rehearing request in the PPL Montana proceeding asserts that the Commission's decision to renew the market-based rate authority of the PPL Montana Companies is error insofar as it is contrary to record evidence and the requirements of the Federal Power Act. The Commission denied Montana Counsel's request for rehearing in *PLL Montana LLC*, 120 FERC ¶ 61,096 (2007).

[162] *Id.* at 8–9.

[163] *Id.* at 9 (citing Order No. 697 at P 25, 63 n.46).

[164] *Id.*

[165] NRECA Rehearing Request at 3, 21 (citing *Cal. ex rel. Lockyer* v. *FERC*, 383 F.3d 1006 (9th Cir. 2004) (*Lockyer*); 5 U.S.C. 706(2)(A), (C)).

[166] *Id.* at 21 (citing *Mo. Pub. Serv. Comm'n* v. *FERC*, 337 F.3d 1066, 1075 (D.C. Cir. 2003) ("Reliance on facts that an agency knows are false at the time it relies on them is the essence of arbitrary and capricious decision making.")).

[167] *Id.* at 22.

[168] *Id.* (citing Motor *Vehicle Mfrs. Ass'n*, 463 U.S. at 43; *Pac. Gas & Elec. Co.* v. *FERC*, 373 F.3d at 1319).

[169] *Id.* at 23 (citing *Lockyer*, 383 F.3d at 1014–15. *See also* TDU Systems Rehearing Request at 17.

[170] TDU Systems Rehearing Request at 7, 16 (citing *Mo. Pub. Serv. Comm'n* v. *FERC*, 337 F.3d 1066, 1075 (D.C. Cir. 2003)).

[171] *Id.* at 17.

[172] Order No. 697 at P 299.

Accordingly, the market-based rate change in status reporting requirement allows the Commission to evaluate changes when they actually happen rather than relying on projections, making it unnecessary and redundant for the Commission to allow sellers to account for predicted changes in the DPT for market-based rate purposes.

126. Furthermore, accounting for ''imminent changes'' would be excessively burdensome with regard to expiring contracts because, for an accurate representation, a review of all expiring contracts and all contracts being negotiated inside all balancing authority areas in the relevant market and the seller's first-tier markets might be necessary. In addition, because the definition of ''imminent'' is a matter of interpretation and may change depending on the circumstances, it would produce regulatory uncertainty. Furthermore, future changes are not necessarily known and measurable. For example, a long-term contract may be expiring in a year, but until it expires, it often can be renewed for the same term(s). Therefore, an analysis that assumes that the long-term capacity of that contract was uncommitted would not always be correct, and therefore could overstate the seller's market power. When a change does occur the Commission has a method to evaluate the new situation through its requirement that sellers with market-based rate authority report changes in status and what effect, if any, such a change has on the grant of market-based rate authority. In any event, the Commission may require a full market power analysis at any time including as a result of a seller's change in status filing.

127. With regard to Montana Counsel's argument that the Commission should allow evidence of known and measurable changes rather than a strict adherence to historical data because if a change in status is caused by the expiration of a long-term contract for the sale of capacity, then by the time a seller's change in status filing is submitted, a seller may have already re-sold the capacity at a price reflecting the seller's underlying market power, we recognize that a seller's change in status filing would not be filed until after a long-term contract expires. However, there are countervailing reasons why the Commission believes that the use of historical data is appropriate and reaffirms its practice of using a ''snapshot in time approach.'' [173] As explained above, the Commission adopted this approach because historical data are more objective, readily available, and less subject to manipulation by sellers than future projections. We reiterate our concern that if the Commission were to require sellers to submit studies or change in status filings based on their future projections such as ''imminent changes,'' then sellers would be able to selectively ''cherry pick'' those changes that benefited the seller in retaining market-based rate authorization while ignoring other equally likely future changes that would undermine the seller's chances for obtaining or retaining market-based rate authorization. Similarly, intervenors could introduce only those imminent changes that result in higher market shares for a seller, thus artificially increasing the seller's market shares. In addition, requiring a seller to submit market power analyses that reflect future or ''imminent changes'' such as the future expiration of a long-term contract would be excessively burdensome because, for an accurate representation, review of all expiring contracts, and all contracts being negotiated inside the relevant market and the seller's home balancing authority area and its first-tier markets may be necessary. Otherwise, the seller's analysis might be incomplete and produce invalid results.

128. In addition, as explained above, future changes are not necessarily known and measurable since a long-term contract may be expiring in a year, but until it expires, it often can be renewed for the same term. Likewise, the Commission does not allow the seller to deduct capacity that it is currently negotiating to sell to third parties. To do so would allow the seller to argue that it has an ''imminent'' sale and the Commission should consider that capacity to be committed, resulting in lowering the seller's market shares. The danger in this circumstance is, like the expiring contract that could be extended, the sale may not actually occur and the seller could appear to have rebutted the presumption of market power when in fact, based on actual data, it has market power. Therefore, an analysis that assumes that the long-term capacity associated with an expiring contract is uncommitted would not always be correct. In addition, because the definition of ''imminent'' is a matter of interpretation and may change depending on the circumstances, it would produce regulatory uncertainty. For all of these reasons, our determination to rely on unadjusted historical data in the indicative screens and the DPT analysis is based on reasoned decision making.

129. Notwithstanding our policy requiring the use of historical data and a ''snapshot in time approach,'' in previous cases we nevertheless have addressed evidence presented by intervenors who sought to demonstrate that upon expiration of a long-term contract, a seller would be able to exercise market power.[174] Indeed, in cases where this issue has arisen, the Commission considered the impact of the expiring long-term contract on the seller's market power and concluded that even when adjustments were made to the available economic capacity measure to account for expiring contracts, the seller did not fail the indicative screens.[175]

130. While we continue to believe that the ''snapshot in time approach'' is appropriate, and will continue to require the use of historical data in the market power analysis, we nevertheless will consider, on a case-by-case basis, clear and compelling evidence presented by sellers and intervenors that seek to demonstrate that certain changes in the market, such as the expiration of a long-term contract, should be taken into account as part of the market power analysis in a particular case. Entities who seek to make this demonstration must present clear and compelling evidence in support of their argument. The Commission will address any countervailing factors that affect whether the seller will have the ability to exercise market power. Such countervailing factors could include, but are not limited to, any competitor that similarly has expiring long-term contracts and any other factors that might impact the market power analysis such as plant retirements, transmission access, and generation upgrades. In this regard, we remind entities that they must perform the market power screens as designed but may also provide a sensitivity analysis consistent with the discussion above.

131. We reject Montana Counsel's argument that, if the Commission considers a seller's proposal to transfer operational control of enough generation to a third party as part of its proposed mitigation so that the seller would satisfy the Commission's horizontal market power concerns, then the Commission should also consider imminent changes that would increase a

[173] For the reasons stated above, we also reject NRECA's argument that the triennial review and the change in status filing will come too late.

[174] *PPL Montana, LLC*, 115 FERC ¶ 61,204, at P 46 (2006), *order denying reh'g*, 120 FERC ¶ 61,096, at P 52–54 (2007); *Boralex Livermore Falls LP*, 122 FERC ¶ 61,033, at P 43 (2008).

[175] *Id.*

seller's market shares. Consideration of a proposal to transfer operational control of generation as part of a seller's proposed mitigation, unlike consideration of imminent changes as part of a seller's market power analysis, does not run the risk that a seller's market power may be hidden. Moreover, the act of transferring control may be enough to reduce the seller's market shares sufficiently to address market power concerns.

8. Transmission Imports

Final Rule

132. In Order No. 697, the Commission adopted the proposal to continue to measure limits on the amount of capacity that can be imported into a relevant market based on the results of a simultaneous transmission import limit (SIL) study.[176] Thus, a seller that owns transmission will be required to conduct simultaneous transmission import capability studies for its home balancing authority area and each of its directly-interconnected first-tier balancing authority areas consistent with the requirements set forth in the April 14 Order, as clarified in *Pinnacle West Capital Corp*.[177] The Commission commented that ''the SIL study is 'intended to provide a reasonable simulation of historical conditions' and is not 'a theoretical maximum import capability or best import case scenario.' '' [178] To determine the amount of transfer capability under the SIL study, the Commission stated that historical operating conditions and practices of the applicable transmission provider should be used and the analysis should reasonably reflect the transmission provider's OASIS operating practices. The Commission will also continue to allow sensitivity studies, but the sensitivity studies must be filed in addition to, not in lieu of, an SIL study.[179]

133. In response to a commenter's suggestion, the Commission stated it would allow the use of simultaneous total transfer capability (TTC) values, provided that these TTCs are the values that are used in operating the transmission system and posting availability on OASIS. In addition, the Commission stated that ''[s]ellers submitting simultaneous TTC values must provide evidence that these values account for simultaneity, account for all internal transmission limitations, account for all external transmission limitations existing in first-tier areas, account for all transmission reliability margins, and are used in operating the transmission system and posting availability on OASIS.''[180]

134. The Commission also agreed with several commenters that short-term firm reservations can be unpredictable, driven by real-time system conditions, and do not necessarily indicate that the associated transmission capacity is not available for competing supplies. Thus, the Commission concluded that, in calculating simultaneous transmission import limits, short-term reservations of 28 days or less in effect during the study periods need not be accounted for.[181]

135. The Commission stated that when actual OASIS practices conflict with the instructions in Appendix E of the April 14 Order, sellers should follow OASIS practices and must provide documentation of these practices.[182] The Commission further stated that the SIL is a benchmark of historical conditions, including peak load, and that if additional supplies could be imported above a market's study year peak load, the Commission will consider a sensitivity study that is submitted in addition to the required SIL study and supported by record evidence.[183]

136. The Commission adopted the requirement for use of the SIL study as a basis for transmission access for both the indicative screens and the DPT analysis.[184] The Commission stated that this requirement assures that all factors important in determining transmission access to the seller's market are taken into account.[185]

Requests for Rehearing

137. APPA/TAPS request clarification that the use of simultaneous TTC in the SIL study must properly account for all firm transmission reservations, transmission reliability margin, and capacity benefit margin.[186] First, APPA/TAPS assert that the Commission should state that clarifications provided in the Final Rule regarding firm reservations apply to any use of simultaneous TTC.[187] APPA/TAPS argue that transmission reserved by a third party should not be double-counted via pro-rata allocation of unused transmission capacity.[188] Second, APPA/TAPS read the Final Rule's mention of the need for simultaneous TTC to ''account for all transmission reliability margins'' [189] as affirming that TRM set-asides should not be included in transmission capability, consistent with the July 8 Order.[190] Third, APPA/TAPS ask the Commission to affirm that it will apply to simultaneous TTC its prior findings in the July 8 Order that CBM set-asides should be reflected in transmission capability as non-firm capability unless they are used for reliability during seasonal peaks, in which case they should not be treated as part of import capability.[191] APPA/TAPS point out that transmission providers do not make CBM available on a firm basis, and when it is used for reliability, it should not be deemed available at all to competing suppliers.[192]

138. Southern states that the Final Rule concludes that short-term reservations of more than 28 days are to be ''accounted for'' in the simultaneous study, which suggests that they should be deducted from the resulting import values. Southern submits that this treatment, if intended by the Commission, is inappropriate and thus should be reconsidered.[193] Instead, Southern argues that such reservations should be assigned to the entity ''that actually controls that generation capacity on a long-term basis and who, by virtue of that long-term control, might actually receive extra financial benefits if the exercise of market power in wholesale electricity markets caused wholesale prices to rise.'' [194] Southern argues that there is a conflict between the section on Control and Commitment, where the Commission concludes ''that the determination of control is appropriately based on a review of the totality of circumstances on a fact-specific basis,'' [195] and the SIL section that effectively assigns to applicants any short-term purchases that they make between one month and one year in duration so long as those purchases are covered with firm transmission reservations. [196]

139. Southern argues that the Commission's ''after-the-fact'' examination of short-term transmission reservations to see how many were more

[176] Order No. 697 at P 354.

[177] 110 FERC ¶ 61,127 (2005).

[178] Order No. 697 at P 354 (internal citations omitted).

[179] *Id.* P 355.

[180] *Id.* P 364.

[181] *Id.* P 368.

[182] *Id.* P 356.

[183] *Id.* P 361.

[184] *Id.* P 384.

[185] *Id.* P 386.

[186] APPA/TAPS Rehearing Request at 28–29 (citing Order No. 697 at P 364, 369; July 8 Order, 108 FERC ¶ 61,026).

[187] *Id.* at 28 (citing Order No. 697 at P 369).

[188] *Id.*

[189] Order No. 697 at P 364.

[190] APPA/TAPS Rehearing Request at 28–29.

[191] *Id.* at 29.

[192] *Id.*

[193] Southern Rehearing Request at 32.

[194] *Id.* at 32–33 (quoting Frame Affidavit at ¶ 20).

[195] Order No. 697 at P 174.

[196] Southern Rehearing Request, Frame Affidavit at ¶ 19.

than 28 days in duration and who made those reservations is arbitrary and capricious decision-making. Southern also contends that the Final Rule is ambiguous and internally inconsistent when the Commission states that short-term firm transmission reservations longer than 28 days must be accounted for in the simultaneous import capability study.[197] The Final Rule also provides that applicants do not need to account for short-term reservations of one month or less. However, according to Southern, the Commission then arbitrarily states that since the shortest month of the year has only 28 days (in non-leap years), reservations longer than 28 days must be accounted for in a simultaneous import capability study. Thus, the Final Rule is internally inconsistent with regard to what constitutes a month, and the Commission selected the length of a month that is contrary to the evidence and is thus arbitrary and capricious.[198] According to Southern, the Commission should grant rehearing and make clear that applicants are not required to address short-term firm transmission reservations in their simultaneous import capability studies.[199]

140. Southern states that although Appendix E required the use of generation scaling for calculating simultaneous import limit, the Final Rule allowed sellers to use another methodology when their actual OASIS practice conflicts with the instructions in Appendix E. Based on this clarification, Southern states that Southern is to use the same load shift methodology that it has historically used in calculating transfer capability for OASIS posting instead of the Appendix E mandated generation scaling. Southern states that in order to simulate a power transfer under the load shift methodology to determine simultaneous import capability into the Southern Companies' balancing authority area for seasonal peak conditions, load in the power flow case is initially set to the seasonal peak load level and served by a comparable amount of generation in accordance with the engineering principle that for each control area, generation must equal load plus losses plus interchange.

[197] *Id.* at 33.

[198] *Id.* at 34 (citing *General Chemical Corp.*, 817 F.2d at 857 (reversing an order that was internally inconsistent); *East Texas Electric Co-op* v. *FERC*, 218 F.3d 750, 754 (D.C. Cir. 2000); *McElroy Elecs. Corp.* v. *FCC*, 990 F.2d 1351, 1358 (D.C. Cir. 1993); *Motor Vehicle Mfrs. Ass'n*, 463 U.S. at 43 (finding that agency rule would be arbitrary and capricious if the explanation runs counter to the evidence before the agency); *FPL* v. *Lorion*, 470 U.S. 729, 744 (1985)).

[199] *Id.* at 34–35.

According to Southern, in order to perform transfer analysis using the load shift methodology, load is uniformly increased in the Southern Companies balancing authority area, while load is simultaneously decreased in first-tier control areas to simulate the appropriate transfer of power between the areas. Southern states that this commonly used methodology has the effect of increasing loads during the transfer to levels that, by definition, exceed the seasonal peak load represented in the power flow case.[200] Southern requests clarification that, for purposes of performing transfer analysis under the load shift methodology, transmission providers may allow the load shift methodology to effect load levels that are higher than the historical peak load levels as the means of simulating transfers. Otherwise, Southern contends that the Final Rule will contain inherently conflicting provisions that, on the one hand direct the use of historical practices related to load shift transfer analyses, but at the same time forbid the methodological process whereby the load shift approach simulates the power flows under study.[201]

141. Southern agrees that a simultaneous import capability study conducted in accordance with Appendix E or historical practice for seasonal peaks may be appropriate for the indicative screens. Further, the same study approach used for the screens may be appropriate for use in a DPT. However, Southern states that there is no legal or policy justification for seeking a more complete analysis of competitive conditions on the generation side, while not permitting a comparable effort pertaining to transmission. Southern argues that to treat these issues differently could potentially lead to serious distortions of the competitive analysis. Therefore, Southern requests that the Commission clarify that the Final Rule does not foreclose an applicant from presenting a more thorough simultaneous import capability study based upon historical conditions as part of a DPT study. Of course, any such presentation would have to be considered on a case-specific basis and it would have to be consistent with the fundamental determinations of Appendix E related to simultaneous feasibility, historical practices and the like.[202]

[200] *Id.* at 31.

[201] *Id.*

[202] *Id.* at 35.

Commission Determination

142. In response to the comments from APPA/TAPS, we clarify that the use of simultaneous TTC in the SIL study must properly account for all firm transmission reservations, transmission reliability margin, and capacity benefit margin. We agree that the clarifications provided in the Final Rule regarding firm reservations apply to all simultaneous transmission import limit studies, including those that use simultaneous TTC.[203] We agree that transmission reserved by a third party should not be double-counted, such as by assuming it is available a second time to other competitors via pro-rata allocation of unused transmission capacity.[204] We affirm that the Final Rule's mention of the need for simultaneous TTC to ''account for all transmission reliability margins'' [205] means that TRM set-asides should not be included in transmission capability, consistent with the July 8 Order.[206] We also affirm that our prior findings in the July 8 Order that capacity benefit margin set-asides should be reflected in transmission capability as non-firm capability unless they are used for reliability during seasonal peaks, in which case they should not be treated as part of import capability, also apply to studies that use simultaneous TTC.[207] APPA/TAPS has correctly interpreted the Final Rule in these respects.

143. Southern argues that there is inconsistency between the proposed treatment of short-term transmission reservations and the Control and Commitment section of Order No. 697. We disagree. In the Control and Commitment section, we refer to the control of a generation asset, including the ability to dispatch the generation asset. In the SIL section, we refer to a firm transmission reservation. These are different. The objective of the SIL calculation is to determine the amount of transmission imports available to bring in supply from first-tier areas.[208]

[203] Order No. 697 at P 369.

[204] APPA/TAPS Rehearing Request at 28.

[205] Order No. 697 at P 364.

[206] APPA/TAPS Rehearing Request at 28–29.

[207] *Id.* at 29.

[208] The Commission recognizes that there may be confusion concerning the use of a pro-rata allocation of generation capacity when performing a simultaneous transmission import limit (SIL) study and the requirement that, when performing the indicative screens, ''[a]ny simultaneous transmission import capability should first be allocated to the seller's uncommitted remote generation. Any remaining simultaneous transmission import capability would then be allocated to any uncommitted competing supplies.'' *See* Order No. 697 at P 38.

With regard to performing a SIL study, pro-rata allocation is used to assign shares to two ''groups''

An applicant's firm transmission reservations represent transmission that is not available to competing suppliers. Applicants who believe that their firm transmission reservations should be treated as available to import competing supply may present evidence that the Commission will consider on a case-by-case basis.

144. In response to Southern's comments regarding short-term transmission reservations, we clarify that for the reasons described in Order No. 697,[209] applicants are not required to address short-term firm reservations in the market power screens. Currently, the Commission's EQR Data Dictionary defines monthly as more than 168 consecutive hours up to one month, and seasonal as greater than one month and less than 365 consecutive days.[210] Twenty-eight days fits within the definition of a month, and is a reasonable limit to separate short-term reservations from long-term reservations for purposes of the generation market power screens. Since the market power screens are conducted for four seasonal periods, and they are designed to model historical conditions during the four seasonal peak periods, the screens must account for transmission reservations typical for each season. It is not practical to require applicants to provide data on every transmission reservation, yet we cannot ignore the impact of transmission reservations on the potential for market power. Requiring applicants to account for reservations greater than one month in duration strikes a balance between allowing the screens to reasonably model historical conditions without requiring unreasonable amounts of information from applicants. Therefore, we will require applicants to allocate their seasonal and longer transmission reservations to themselves from the calculated SIL, where seasonal reservations are greater than one month and less than 365 consecutive days in duration, as defined in the Commission's EQR Data Dictionary.

145. We grant the clarification Southern seeks in part. We would allow sellers to use load shift methodology to calculate simultaneous import limit while scaling their load beyond the historical peak load, provided they submit adequate support and justification for the scaling factor used in their load shift methodology and how the resulting SIL number compares had the company used a generation shift methodology.

146. In response to Southern's request for clarification regarding whether applicants may present more thorough simultaneous import capability studies based upon historical conditions as part of a DPT study, we clarify that, as we stated in the Final Rule, applicants may submit additional sensitivity studies, including a more thorough import study as part of the DPT. We reaffirm, however, that any such sensitivity studies must be filed in addition to, and not in lieu of, an SIL study.[211]

9. Further Guidance Regarding Control and Commitment of Capacity

147. In Order No. 697, the Commission concluded that the determination of control is appropriately based on a review of the totality of circumstances on a fact-specific basis. We explained that no single factor or factors necessarily results in control. We further explained that the electric industry remains a dynamic, developing industry, and no bright-line standard will encompass all relevant factors and possibilities that may occur now or in the future. If a seller has control over certain capacity such that the seller can affect the ability of the capacity to reach the relevant market, then that capacity should be attributed to the seller when performing the generation market power screens.[212]

148. We determined that the circumstances or combination of circumstances that convey control vary depending on the attributes of the contract, the market and the market participants. Therefore, we concluded that it would be inappropriate to make a generic finding or generic presumption of control, but rather that it is appropriate to continue making our determinations of control on a fact-specific basis. We explained, however, that we continue our historical approach of relying on a set of principles or guidelines to determine what constitutes control. Thus, we stated that we continue to consider the totality of circumstances and attach the presumption of control when an entity can affect the ability of capacity to reach the market. We explained that our guiding principle is that *an entity controls the facilities when it controls the decision-making over sales of electric energy, including discretion as to how and when power generated by these facilities will be sold*.[213]

149. We declined to adopt commenters' suggestions that we require all relevant contracts to be filed for review and determination by the Commission as to which entity controls a particular asset (e.g., with an initial application, updated market power analysis, or change in status filing). While we noted that under section 205 of the FPA, the Commission may require any contracts that affect or relate to jurisdictional rates or services to be filed, we explained that the Commission uses a rule of reason with respect to the scope of contracts that must be filed and does not require as a matter of routine that all such contracts be submitted to the Commission for review. Our historical practice has been to place on the filing party the burden of determining which entity controls an asset. Therefore, we required a seller to make an affirmative statement as to whether a contractual arrangement transfers control and to identify the party or parties it believes control the generation facility, but explained that the Commission retains the right at the Commission's discretion to request the seller to submit a copy of the underlying agreement(s) and any relevant supporting documentation.

150. Given the increased level of investment in the electric utility industry as a result of the Energy Policy Act of 2005 (EPAct 2005) [214] and our implementing rules and regulations, we find it necessary to provide further guidance with respect to the representations that a seller should make regarding which entity controls a particular asset. An increasing number

of uncommitted generation capacity in the aggregated first-tier market. The seller must first calculate the sum of its owned and affiliated uncommitted generation capacity, then it must sum all other sellers' uncommitted generation capacity. The seller then divides these two numbers to compute a ratio of the seller's (and affiliated) uncommitted generation capacity to all other sellers' uncommitted generation which determines the ''share'' that each seller is allocated to import into the study area. In other words, when performing the SIL study, any uncommitted generation capacity in the aggregate first-tier market is allocated pro-rata for the purpose of determining the value of the SIL.

With regard to performing the indicative screen analyses, all of the seller's and its affiliated uncommitted generation capacity in first-tier markets (remote capacity) should be allocated to the seller's total uncommitted capacity in the relevant market (study area), up to the SIL limit. Any remaining simultaneous transmission import capability is then allocated to any uncommitted competing generation.

For example, if the SIL limit is 200 MW, the seller and its affiliates' uncommitted generation capacity in first-tier markets is 150 MW, and competing uncommitted generation capacity in first-tier markets is 350 MW, then to properly perform the indicative screens the seller's uncommitted generation capacity in the relevant market is increased by 150 MW and competing supply in the relevant market is increased by 50 MW.

[209] Order No. 697 at P 368.

[210] *Order Adopting Electric Quarterly Report Data Dictionary*, Order No. 2001–G, 72 FR 56735 (Oct. 4, 2007), 120 FERC ¶ 61,270, at P 35 (2007).

[211] *Id.* P 355.

[212] Order No. 697 at P 174.

[213] *Id.* P 175.

[214] Energy Policy Act of 2005, Pub. L. No. 109–58, 119 Stat. 594 (2005).

of investors are acquiring interests in assets that may be relevant to a seller's market-based rate authority. As we explained in Order No. 697, we will continue to place on the filing party the burden of determining which entity controls an asset. We will rely on the seller's representations regarding control, absent extenuating circumstances. Therefore, to provide further guidance to the industry, we reiterate that the seller, in advising the Commission of its determinations of control, should specifically state whether a contractual arrangement transfers control and should identify the party or parties it believes control(s) the generation facility. In doing so, the seller should make its representation in light of our discussion in Order No. 697 and cite to that order as the basis for which it has made its determination.

B. Vertical Market Power

1. OATT Violations and Market-Based Rate Revocation

Final Rule

151. In the Final Rule, the Commission stated it will revoke an entity's market-based rate authority in response to an OATT violation upon a finding of a nexus between the specific facts relating to the OATT violation and the entity's market-based rate authority, and reiterated that an OATT violation may subject the seller to other remedies the Commission may deem appropriate, such as disgorgement of profits or civil penalties.[215] The finding that an OATT adequately mitigates transmission market power rests on the assumption that individual entities comply with the OATT and that there may be OATT violations in circumstances that, after applying the factors in the Enforcement Policy Statement,[216] merit revocation or limitation of market-based rate authority. The Final Rule found, however, that it is inappropriate to revoke a seller's market-based rate authority for an OATT violation unless there is a nexus between the specific facts relating to the OATT violation and the seller's market-based rate authority. The Commission declined to adopt a rebuttable presumption that any OATT violation has the requisite nexus to support revocation of market-based rate authority, explaining that there is a wide range of types of OATT violations, including ones that may be inadvertent and others that are neither intended to affect, nor in fact affect, the market-based rate sales of the transmission provider or its affiliates.[217]

152. The Commission stated that determining what constitutes a sufficient factual nexus is best left to a case-by-case consideration, explaining that the wide range of positions among commenters on how to define a sufficient factual nexus itself suggested that this finding is best made after review of a specific factual situation. Some commenters had asserted that a finding of a ''material'' violation of the OATT would be sufficient. The Commission disagreed. While a seller's inconsequential OATT violation would not serve as a basis for revoking that entity's market-based rate authority, the Commission stated that revocation is warranted only when an OATT violation has occurred and the violation had a nexus to the market-based rate authority of the violator or its affiliates.[218] The Commission also clarified that it will allow intervenors on a case-by-case basis to file evidence if they believe they have been denied transmission access in violation of the OATT.[219]

153. The Commission emphasized in the Final Rule that it has discretion to fashion remedies for OATT violations that relate to the violator's market-based rate authority in instances in which the Commission does not find sufficient justification for revocation of that authority. For example, in appropriate circumstances, the Commission may modify or add additional conditions to the violator's market-based rate authority or impose other requirements to help ensure that the violator does not commit future, similar misconduct. The Commission also explained that it will consider whether to impose sanctions such as assessment of civil penalties for particularly serious OATT violations in addition to revocation of the violator's market-based rate authority.[220]

Requests for Rehearing

154. NRECA and TDU Systems argue that the Final Rule's determination that the Commission will not revoke the market-based rate authority of a public utility or its affiliates upon the utility's violation of its OATT unless there is a ''nexus'' between the ''specific facts'' of the violation and the violator's market-based rate authority is arbitrary, capricious, contrary to law, and in excess of statutory authority. NRECA also argues that the Final Rule does not provide clear guidance as to what would constitute a sufficient nexus.[221]

155. TDU Systems state that the Commission must clarify the circumstances in which it will find that there is a sufficient nexus between a transmission provider's OATT violations and the revocation of market-based rate authorization of the provider or its affiliates, and reconsider its decision to determine what constitutes a sufficient factual nexus on a case-by-case basis.[222] TDU Systems state that, apart from trivial violations, which could be screened out by the kind of materiality filter suggested by APPA/TAPS,[223] the Commission has not explained why material OATT violations should not create at least a presumption that market-based rate authorization is inappropriate.[224] TDU Systems state that, because having an OATT on file and being bound by its terms are necessary to mitigating the public utility's vertical market power, there is logical reason to be concerned that a violation may have undermined a premise for the authorization. TDU Systems therefore assert that an OATT violation should automatically trigger a Commission proceeding in which the violator has the burden of justifying its continued market-based rate authority.[225] Furthermore, TDU Systems state that shifting the burden to the transmission provider could encourage transmission providers to be in full compliance with coordinated and open regional planning.[226]

156. TDU Systems also argue that the Commission needs to address further the content of the ''nexus'' requirement. They contend that transmission-owning public utilities might read Order No. 697 to allow for revocation of their market-based rate authority only when it would be arbitrary and capricious for the Commission not to do so.[227] TDU Systems contend that the Commission has offered no clue to understanding why it may be relevant whether the alleged violator has committed an OATT violation in order to further a specific sale under its own market-based rate tariff or that of an affiliate. TDU Systems conclude that if such a connection is indeed critical, there would appear to be a substantial danger of deflecting attention from the characteristics of a transmission

[215] Order No. 697 at P 417.

[216] *Enforcement of Statutes, Orders, Rules and Regulations,* 113 FERC ¶ 61,068 (2005) (Enforcement Policy Statement).

[217] Order No. 697 at P 417.

[218] *Id.* P 418.

[219] *Id.* P 421.

[220] *Id.* P 419.

[221] NRECA Rehearing Request at 28 (citing Order No. 697 at P 418).

[222] TDU Systems Rehearing Request at 8, 20.

[223] *Id.* at 21 (citing APPA/TAPS Initial Comments at 81).

[224] *Id.* at 8, 21.

[225] *Id.* at 21.

[226] *Id.* at 8.

[227] *Id.* at 22.

provider's conduct, *i.e.*, whether it is anticompetitive or reflects the exercise of market power.[228]

157. These petitioners claim that the Commission's position appears to place the burden of proof on customers, competitors, or the Commission to demonstrate the nexus, rather than requiring the violator to demonstrate the lack of any such nexus.[229]

158. NRECA asserts that when a public utility violates its OATT, one of the preconditions to the grant of market-based rate authority is violated. It argues that, under the FPA, the seller, not customers, must bear the burden of proof that its continuing sales under its market-based rate tariff remain at just and reasonable levels.[230] NRECA therefore contends that there should be a presumption that there is a ''nexus'' between the OATT violation and the seller's market-based rate authority.[231] NRECA states that the burden, consistent with the FPA, should be on the seller to rebut this presumption; however, it suggests that the Commission could evaluate the seller's showing, and if the issue is in doubt, set the matter for investigation or hearing and order a temporary suspension of market-based rate authority until the matter is resolved.[232]

Commission Determination

159. The Commission denies rehearing of the decision to require a factual nexus between a substantial OATT violation and the entity's market-based rate authority to justify revocation of that authority. As the Commission explained in Order No. 697, the ''nexus condition'' is required in order to ensure that our actions are not arbitrary or capricious or based on an inadequate factual record. We disagree with NRECA and TDU Systems that any material OATT violation should necessarily justify revocation of the entity's market-based rate authority since the violation may have no relation to the market-based rate authority. In such circumstances, the Commission will consider such other remedies as may be appropriate. We also decline to provide specific examples of what would constitute a sufficient nexus between an entity's market-based rate authority and an OATT violation because the factual circumstances involved in a claimed violation will be unique to the company and, therefore, any list would be incomplete. This is especially true in light of continually developing markets. We continue to believe that the determination of what would be a sufficient factual nexus between an OATT violation and revocation of the violator's market-based rate authority is best left to case-by-case consideration.

160. With regard to the transmission provider's planning obligations in particular, violations of the planning-related requirements of the *pro forma* OATT may or may not have a sufficient factual nexus with the transmission provider's market-based rate authority. A case-by-case analysis will be necessary to determine if the violation justifies revocation of the transmission provider's market-based rate authority. We agree with TDU Systems that OATT violations by a transmission provider that may not be explicitly connected with its market-based rate authorization may nonetheless promote conditions in which the violator could gain an advantage in future transactions. However, we note that this is an example of why a case-by-case determination is needed so that the Commission can consider the violation, the seller's market-based rate authority, and market conditions in determining what remedy, if any, best suits the situation. Therefore, we will apply the mechanisms adopted in Order No. 890 to aid us in determining on a case-by-case basis if a particular violation puts that company at an advantage vis-á-vis its market-based rate authority.[233]

161. We disagree with TDU Systems and NRECA that the Commission inappropriately shifted the burden of proof regarding whether there is a nexus. We anticipate that the Commission's consideration of a seller's OATT violation and whether or not there is a nexus with its market-based rate authority would normally arise as part of a Commission-initiated enforcement proceeding. In enforcement proceedings, the Commission has considerable discretion in how to fashion an appropriate remedy and the burden of justifying any remedial actions taken against a violator, including revocation of market-based rate authority and determining what remedies are required to ensure that any future sales, market-based rate or otherwise, are at just and reasonable rates. Moreover, even if the issue arose in publicly noticed proceedings (such as a section 206 or 306 complaint), the Commission would exercise its remedial discretion based on the facts presented and accordingly bear the burden of justifying any remedy imposed on the transmission provider for a violation of its OATT. Whether or not a violation justifies revocation of the seller's market-based rate authority will depend on the facts and circumstances involved in each case; therefore, it would not be appropriate to adopt a presumption of that nexus, as requested by petitioners. The Commission will make a determination based on the facts of each particular case as to whether or not an OATT violation has a nexus to the seller's market-based rate authority. In sum, the Commission's action in Order No. 697 does not shift the burden of proving a nexus to customers and competitors.

162. Contrary to TDU Systems' assertion, Order No. 697 does not limit the Commission to revoking a seller's market-based rate authority only in circumstances where it would be arbitrary and capricious not to do so. If an OATT violation occurs, the Commission will investigate whether or not the facts surrounding the violation have a nexus to the seller's market-based rate authority. It would not be just and reasonable for the Commission to revoke a seller's market-based rate authority if in fact the violation had no bearing on the seller's market-based rate position. The way to make such a determination is based on an adequate factual record and that is what would be established in such a proceeding before making any determinations.

2. Treatment of FTRs

Final Rule

163. In the Final Rule, the Commission stated that provisions concerning the reassignment or sale of transmission capacity or firm transmission rights, congestion contracts, or fixed transmission rights (as a group, FTRs) are not required to be included in a seller's market-based rate tariff, nor is it appropriate to include transmission-related services in a seller's market-based rate tariff.[234] The Commission explained that Commission-approved market rules for RTO/ISOs address resales of FTRs and virtual trading to ensure that no market power is exercised in such trades. In addition, sellers engaging in these activities sign a participation agreement with RTO/ISOs which require them to abide by those market rules. Hence, the approval of the market rules in conjunction with approval of the generic participation agreement by the Commission constitutes authorization for public utilities to engage in the

[228] *Id.*

[229] NRECA Rehearing Request at 3, 27–29; TDU Systems Rehearing Request at 3–4, 20.

[230] NRECA Rehearing Request at 28 (citing *Lockyer*, 383 F.3d at 1014–15; 16 U.S.C. 824d(e)).

[231] *Id.* at 29.

[232] *Id.*

[233] *See* Order No. 890–A, FERC Stats. & Regs. ¶ 31,261 at P 1037.

[234] Order No. 697 at P 920.

resale of FTRs and virtual transactions, and no separate authorization is required under the FPA.

Requests for Rehearing

164. Morgan Stanley states that, when assessing whether a potential market-based rate seller has market power, the Commission has focused on ownership and control of physical transmission (except for that which is necessary to interconnect generation to the transmission grid).[235] Morgan Stanley requests that the Commission clarify whether a seller is required to include and report the acquisition of financial transmission rights when assessing whether it has vertical market power. Morgan Stanley states that the Commission declined to adopt such a requirement as part of Order No. 652 governing changes in status.[236] However, Morgan Stanley asserts that ''Commission staff and others have taken inconsistent positions on whether the failure to disclose the acquisition of financial transmission rights constitutes a violation of a seller's market-based rate tariff.''[237]

Commission Determination

165. The Commission clarifies herein that sellers are not required to report on financial transmission rights as part of the vertical market power assessment. Thus, failure to disclose the acquisition of financial transmission rights in an application for market-based rate authority, a three-year update or a change in status filing does not constitute a violation of a seller's market-based rate tariff. While ownership of financial transmission rights could affect a seller's incentive to exercise market power, we find that there are adequate mechanisms and protections in place to minimize a seller's ability to do so (e.g., market monitoring and mitigation in RTO/ISOs; the requirement that a seller must abide by its OATT and any violation thereof could constitute a violation of a seller's market-based rate tariff; the Commission's enforcement proceedings). Moreover, the Commission does not analyze *physical* rights that a seller has to transmission service when analyzing vertical market power, and the Commission will treat financial rights in an equal manner. Physical and financial rights to transmission service do not enable the customer to control transmission capacity in a way that withholds the capacity from the market. To the extent there is an issue with potential market manipulation by a seller, the Commission would address this through an Office of Enforcement proceeding.

3. Other Barriers to Entry

Final Rule

166. The Final Rule adopted the NOPR proposal to consider a seller's ability to erect other barriers to entry as part of the vertical market power analysis, but modified the requirements when addressing other barriers to entry. It also provided clarification regarding the information that a seller must provide with respect to other barriers to entry (including which inputs to electric power production the Commission will consider as other barriers to entry) and modified the proposed regulatory text in that regard.[238]

167. In the Final Rule, the Commission drew a distinction between two categories of inputs to electric power production: One consisting of natural gas supply, interstate natural gas transportation (which includes interstate natural gas storage), oil supply, and oil transportation; and another consisting of intrastate natural gas transportation, intrastate natural gas storage or distribution facilities, sites for generation capacity development, and sources of coal supplies and the transportation of coal supplies such as barges and rail cars.[239]

168. With regard to the first category, the Commission removed the inputs from the vertical market power analysis. Thus, the Final Rule did not require a description of or affirmative statement with regard to ownership or control of, or affiliation with an entity that owns or controls, natural gas and oil supply, including interstate natural gas transportation and oil transportation.[240] The Commission explained that prices for wellhead sales of natural gas were decontrolled by Congress,[241] and that the Commission has granted other sellers blanket authority to make such sales at market rates. In the case of transportation of natural gas, the Commission noted that pipelines operate pursuant to the open and non-discriminatory requirements of Part 284 of the Commission's regulations;[242] these regulations mandate that all available pipeline capacity be posted on the pipelines' website, and that available capacity cannot be withheld from a shipper willing to pay the maximum approved tariff rate. The Commission noted that, to the extent intervenors are concerned about a seller's market power from ownership or control of interstate natural gas transportation, this would be actionable first in a complaint proceeding under section 5 of the Natural Gas Act before turning to market-based rate consequences, if any.[243]

169. Similarly, the Commission noted that oil pipelines are common carriers under the Interstate Commerce Act, specifically under section 1(4), that they are required to provide transportation service ''upon reasonable request therefore,'' and that Congress has not chosen to regulate sales of oil.[244]

170. With regard to the second category of inputs to electric power production, the Commission adopted a rebuttable presumption that sellers cannot erect barriers to entry with regard to the ownership or control of, or affiliation with any entity that owns or controls, those inputs.[245] The Commission noted that, to date, it has not found such ownership, control or affiliation to be a potential barrier to entry warranting further analysis in the context of market-based rate proceedings. However, unlike the first category of inputs, the Commission does not have sufficient evidence to remove these inputs from the analysis entirely. Accordingly, the Commission stated that it will rebuttably presume that ownership or control of, or affiliation with an entity that owns or controls, any of the second category of inputs does not allow a seller to raise entry barriers, but intervenors will be allowed to

[235] Morgan Stanley Rehearing Request at 1–2 (citing *Iowa Power Partners,* 81 FERC ¶ 61,058, at 61,281 (1997)).

[236] *Reporting Requirement for Changes in Status for Public Utilities with Market-Based Rate Authority,* Order No. 652, 70 FR 8253 (Feb. 18, 2005), FERC Stats. & Regs. ¶ 31,175, *order on reh'g,* 111 FERC ¶ 61,413 (2005).

[237] Morgan Stanley Rehearing Request at 2. (citing *Enron Power Marketing*, 119 FERC ¶ 63,013 (2007) (discussing Enron's use of FTRs to exercise market power and its failure to report its FTRs to the Commission)).

[238] Order No. 697 at P 440.

[239] *Id.* P 441.

[240] *Id.* P 442.

[241] *INGAA* v. *FERC,* 285 F.3d 18 (D.C. Cir. 2002); Natural Gas Decontrol Act of 1989, H.R. Rep. No. 101–29, 101st Cong., 1st Sess., at 6 (1989).

[242] Order No. 697 at P 443 (citing *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation*; and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, Order No. 636, 57 FR 13267 (Apr. 16, 1992), FERC Stats. & Regs., Regulations Preambles January 1991–June 1996 ¶ 30,939 (Apr. 8, 1992); *Regulation of Short-Term Natural Gas Transportation Services and Regulation of Interstate Natural Gas Transportation Services,* Order No. 637, FERC Stats. & Regs., Regulations Preambles July 1996–December 2000 ¶ 31,091 (Feb. 9, 2000); *clarified,* Order No. 637–A, FERC Stats. & Regs., Regulations Preambles July 1996–December 2000) ¶ 31,099 (May 19, 2000); *reh'g denied,* Order No. 637–B, 92 FERC ¶ 61,062 (2000); *aff'd in part and remanded in part sub nom.*).

[243] Order No. 697 at P 445.

[244] *Id.* P 444 (quoting 49 App. U.S.C. 1(4)).

[245] *Id.* P 446. The Commission modified the definition of ''inputs to electric power production'' in 18 CFR 35.36(a)(4) to reflect this clarification.

demonstrate otherwise. The Final Rule noted that this rebuttable presumption only applies if the seller describes and attests to these inputs to electric power production in its market power analysis, as discussed below.[246]

171. The Commission required a seller to provide a description of its ownership or control of, or affiliation with an entity that owns or controls, any of the second category of inputs. The Final Rule required sellers to provide this description and to make an affirmative statement, with some modifications to the affirmative statement from what was proposed in the NOPR. Instead of requiring sellers to make an affirmative statement that they have not erected barriers to entry into the relevant market, the Final Rule required sellers to make an affirmative statement that they have not erected barriers to entry into the relevant market and will not erect barriers to entry into the relevant market. The Final Rule clarified that the obligation in this regard applies both to the seller and its affiliates, but is limited to the geographic market(s) in which the seller is located.[247]

172. Therefore, the Final Rule modified the proposed regulations to require a seller to provide a description of its ownership or control of, or affiliation with an entity that owns or controls these types of assets, to ensure that this information is included in the record of each market-based rate proceeding. In addition, the Commission required sellers to make an affirmative statement that they have not erected barriers to entry into the relevant market and will not erect barriers to entry into the relevant market.[248]

173. The Commission also modified the change in status reporting requirement in § 35.42 of the Commission's regulations to be consistent with the other barriers to entry part of the vertical market power analysis as adopted in the Final Rule.

Requests for Rehearing

174. Southern notes that the Final Rule modified the change in status regulations adopted by the Commission in Order No. 652. Specifically, Southern states that the Commission modified the definition of inputs to electric power production to mean '' 'intrastate natural gas transportation, intrastate natural gas storage or distribution facilities; sites for new generation capacity development; sources of coal supplies and the transportation of coal supplies such as barges and railcars,' '' [249] and comments that under the change in status reporting regulations, sellers would be required to notify the Commission of any changes to such inputs. Southern requests clarification of what is meant by the phrase ''sources of coal supplies and the transportation of coal supplies such as barges and railcars'' in the context of the definition of ''inputs to electric power production.'' Because such inputs to electric power production are considered in the Commission's vertical market power analysis,[250] Southern believes that the Commission's intention is for this phrase to mean *physical* coal sources (*i.e.*, coal mines) and ownership or control over *who may access* transportation of coal via barges and railcar trains (e.g., control of a train system, a railcar manufacturing or supply company, or a barge production or supply company), rather than merely entering into a coal supply contract with a coal vendor. Southern argues that if a change in status filing were required every time a large utility entered into a coal purchase agreement, purchased or leased a single railcar or barge, or engaged in other such routine activities, which Southern asserts are a necessary and inherent part of keeping power plants operating so that they can reliably serve a utility's customers, the Commission could find itself inundated with submissions. Accordingly, Southern requests that the Commission clarify that the phrase ''inputs to electric power production'' is intended to encompass physical coal sources and ownership of control over who may access transportation of coal via barges and railcar trains.

175. APPA/TAPS request that the Commission clarify that intervenors may introduce evidence that control and/or ownership of interstate natural gas supply, transportation or storage, as well as oil supply and transportation, creates entry barriers.[251] APPA/TAPS request clarification that the Final Rule's stated case-by-case consideration of other entry barriers will include evidence that a seller's or its affiliate's ownership or control of the first category of entry barriers will be considered.[252] According to APPA/TAPS, if, as the Commission believes, markets in the first category are competitive, intervenors will rarely raise concerns about them in specific cases, which means there is no basis to reject this requested clarification on grounds that allowing intervenors to raise entry concerns will be unduly burdensome for applicants or the Commission. APPA/TAPS contend that if there are concerns about these entry barriers, the Commission provides no justification for requiring an intervenor to undertake the time and expense of a '' 'complaint proceeding under section 5 of the Natural Gas Act before turning to market-based rate consequences.' '' [253] Further, APPA/TAPS state that by allowing intervenor evidence regarding market issues surrounding the first category of inputs, the market-based rate program '' 'will allow unique or newly developed barriers to entry to be brought before the Commission.' '' [254]

Commission Determination

176. We agree with Southern that it was not the Commission's intent for the term ''inputs to electric power production'' to encompass every instance of a seller entering into a coal supply contract with a coal vendor in the ordinary course of business. The Commission clarifies that Order No. 697 encompasses *physical* coal sources and ownership of or control over *who may access* transportation of coal via barges and railcar trains. Thus, the Commission will revise its definition of ''inputs to electric power production'' in § 35.36(a)(4) as follows: ''intrastate natural gas transportation, intrastate natural gas storage or distribution facilities; sites for new generation capacity development; physical coal supply sources and ownership of or control over who may access transportation of coal supplies.''

177. The Commission denies APPA/TAPS' request that the Commission clarify that intervenors may introduce evidence that control and/or ownership of interstate natural gas supply, transportation or storage, as well as oil supply and transportation, create entry barriers. As explained above and in Order No. 697, prices for wellhead sales were decontrolled by Congress,[255] and the Commission has granted other sellers blanket authority to make such sales at market rates. In the case of transportation of natural gas, pipelines operate pursuant to the open and non-discriminatory requirements of Part 284 of the Commission's regulations; [256]

[246] *Id.* P 446.

[247] *Id.* P 447.

[248] *Id.* P 448.

[249] Southern Rehearing Request at 41 (citing Order No. 697 at P 1016).

[250] *Id.* at 41 (citing Order No. 697 at P 446).

[251] APPA/TAPS Rehearing Request at 29–30 (citing Order No. 697 at P 441–49; *United States* v. *Enova Corp.*, 107 F. Supp. 2d 10 (D.D.C. 2000)).

[252] *Id.* at 30.

[253] *Id.* (quoting Order No. 697 at P 445).

[254] *Id.* (quoting Order No. 697 at P 449).

[255] *INGAA* v. *FERC*, 285 F.3d 18 (D.C. Cir. 2002); Natural Gas Decontrol Act of 1989, H.R. Rep. No. 101–29, 101st Cong., 1st Sess., at 6 (1989).

[256] Order No. 697 at P 443 (*and cases cited therein*).

these regulations require that all available pipeline capacity be posted on the pipelines' Web site, and that available capacity cannot be withheld from a shipper willing to pay the maximum approved tariff rate. Similarly, the Final Rule noted that oil pipelines are common carriers under the Interstate Commerce Act, specifically under section 1(4), that they are required to provide transportation service ''upon reasonable request therefore,'' and that Congress has not chosen to regulate sales of oil.[257]

178. As stated in the Final Rule, to the extent intervenors are concerned about a seller's market power from ownership or control of interstate natural gas transportation, this would be actionable first in a complaint proceeding under section 5 of the Natural Gas Act before turning to any market-based rate consequences.

179. The Commission found in Order No. 697 and we reiterate here that there is no need to address these inputs to electric power production as potential barriers to entry in the context of the market-based rate program. In light of the precedent described above, we conclude that sellers cannot erect barriers to entry with regard to such inputs.

180. Regarding APPA/TAPS' assertion that the Commission provides no justification for requiring an intervenor to file a complaint proceeding under section 5 of the Natural Gas Act when a concern arises regarding interstate natural gas transportation, as explained in Order No. 697, natural gas pipelines operate pursuant to the open and non-discriminatory requirements of Part 284 of the Commission's regulations. On this basis, the appropriate forum for addressing a concern that may arise regarding interstate natural gas transportation would initially be a proceeding under the Natural Gas Act, not the FPA. Thus, a market-based rate proceeding would not be the proper forum for such a complaint. The place to challenge a particular seller's potential market power in interstate natural gas transportation markets is in a complaint proceeding under section 5 of the Natural Gas Act.

C. Affiliate Abuse

181. In Order No. 697, the Commission determined that affiliate abuse should no longer be considered a separate ''prong'' of the market-based rate analysis, and instead codified the affiliate requirements and restrictions as an explicit requirement in section 35.39 of the Commission's regulations. The affiliate requirements and restrictions must be satisfied on an ongoing basis as a condition of obtaining and retaining market-based rate authority.[258] The regulations expressly prohibit power sales between a franchised public utility with captive customers and any market-regulated power sales affiliate, without first receiving Commission authorization for the transaction under section 205 of the FPA. The regulations also include the requirements formerly known as the market-based rate ''code of conduct,'' as revised in Order No. 697.

1. General Affiliate Terms & Conditions

a. Affiliate Definition

182. As an initial matter, we clarify that the term ''affiliate'' for purposes of Order No. 697 and the affiliate restrictions adopted in § 35.39 of our regulations is defined as that term is used in the regulations adopted in the Affiliate Transactions Final Rule. In the Affiliate Transactions Final Rule, the Commission considered the use of the term affiliate in the context of the Affiliate Transactions NOPR, the Commission's Standards of Conduct for Transmission Providers, and other precedent.[259] The Commission also reviewed the affiliate definitions contained in both the Public Utility Holding Company Act of 1935 (PUHCA 1935)[260] and the Public Utility Holding Company Act of 2005 (PUHCA 2005)[261]. After taking into account these differing definitions of affiliate, and recognizing the need to provide greater clarity and consistency in our rules, the Commission explained that it believes it is important to try to adopt a more consistent definition in its various rules and also one that is sufficiently broad to allow us to adequately protect customers.[262] On this basis, the definition of affiliate as adopted in the Affiliate Transactions Final Rule explicitly incorporates the PUHCA 1935 definition of affiliate for EWGs (rather than incorporate it by reference as previously has been done).[263] The definition also adopts a parallel definition of affiliate for non-EWGs, but with adjustments to reflect the previously-used 10 percent voting interest threshold for non-EWGs and to eliminate certain language not applicable or necessary in the context of the FPA.

183. In light of the Commission's goal to have a more consistent definition of affiliate for purposes of both EWGs and non-EWGs to the extent possible, as well as to strengthen the Commission's ability to ensure that customers are protected, we clarify that, for purposes of Order No. 697, we will define ''affiliate'' as that term is used in the Affiliate Transactions Final Rule, codified in § 35.43(a)(1) of the Commission's regulations. Accordingly, as discussed herein, we will codify the definition of affiliate in our market-based rate regulations at § 35.36.

b. Definition of Market-Regulated Power Sales Affiliate

Final Rule

184. The Commission explained in Order No. 697 that the market-based rate affiliate restrictions codified in § 35.39 govern the relationship between a franchised public utility with captive customers and its market-regulated power sales affiliates.[264] The affiliate restrictions codified in the regulations include a provision expressly prohibiting power sales between a franchised public utility with captive customers and a market-regulated power sales affiliate without first receiving Commission authorization.[265] The

[257] *Id.* P 444 (quoting 49 App. U.S.C. 1(4)).

[258] A seller seeking market-based rate authority must provide information regarding its affiliates and its corporate structure or upstream ownership. To the extent that a seller's owners are themselves owned by others, the seller seeking to obtain or retain market-based rate authority must identify those upstream owners. Sellers must trace upstream ownership until all upstream owners are identified. Sellers must also identify all affiliates. Finally, an entity seeking market-based rate authority must describe the business activities of its owners, stating whether they are in any way involved in the energy industry.

[259] *See,* e.g., *Morgan Stanley Capital Group, Inc.*, 72 FERC ¶ 61,082, at 61,436–37 (1995) (*Morgan Stanley*).

[260] 15 U.S.C. 79a *et seq.*

[261] EPAct 2005 at 1261 *et seq.*

[262] For example, we adopt this definition of affiliate for purposes of section 203 of the FPA in the Affiliate Transactions Final Rule.

[263] We note that in EPAct 2005 section 1277(b)(2), Congress enacted a conforming amendment which amended FPA section 214 to refer to the section 2(a) PUHCA 2005 definition of ''affiliate'' rather than the section 2(a) PUHCA 1935 definition of ''affiliate.'' Our Affiliate Transactions Final Rule did not recognize this conforming amendment. However, the conforming amendment is ambiguous. There is no section 2(a) in PUHCA 2005 and, inexplicably, the text of PUHCA 2005 retained only a portion of the full PUHCA 1935 definition of ''affiliate;'' although it retained the PUHCA 1935 threshold of five percent, it dropped much of the statutory text, thus leaving a potential gap in the scope of entities that could be considered affiliates. It is unclear whether this was a drafting oversight, but we do not believe Congress intended to preclude the Commission, in adopting regulations preventing cross-subsidization, undue preferences or the exercise of market power from using an ''affiliate'' definition that provides greater customer protection with respect to EWG transactions. Our Affiliate Transactions Final Rule and this rule thus use the 1935 statutory text framework for EWGs. We adopt the definition of affiliate promulgated in the Affiliate Transactions Final Rule with a modification to reflect the approach discussed herein.

[264] *Id.* at P 549.

[265] *Id.* at P 467.

Commission defined market-regulated power sales affiliate to mean ''any power seller affiliate other than a franchised public utility, including a power seller affiliate, whose power sales are regulated in whole or in part at market-based rates.'' [266]

Requests for Rehearing

185. Occidental states that, in its current form, Order No. 697 could be interpreted to permit franchised public utilities to require their captive customers to subsidize their market-based rate activities, so long as their regulated and market-based rate activities were combined in a single entity.[267] To prevent that result, Occidental requests that the Commission explicitly require that the functional attributes, rather than the arbitrary structure of a utility, be considered in determining compliance with the rule's affiliate abuse provisions.[268] Occidental states that the Commission should focus on potential market-based rate seller conduct rather than on artificial structural distinctions selected by the seller.[269]

186. Specifically, Occidental argues that, because Order No. 697 focuses solely on conduct between a utility and a legally separate affiliate, it would allow a utility to benefit its market-based rate activities at the expense of its captive regulated customers simply by collapsing its regulated and market-based rates sales activities into a single entity that, while not technically an affiliate of the utility, could attempt to engage in the abuses that Order No. 697 seeks to prevent.[270] Occidental asserts that the Commission can focus on potential market-based rate seller conduct, rather than on artificial structural distinctions selected by the seller, by clarifying that it will not focus solely on the narrow definitions of franchised public utility, captive customer, and market-regulated power sales affiliate, but instead will use a functional test that broadly applies the concept embodied in the rule to seller conduct.

187. Occidental states that the Commission should either clarify that the affiliate abuse requirements of the rule apply equally to market-regulated functions performed within a franchised public utility, or revise the definition of market-regulated power sales affiliate to achieve that same result.[271] In the alternative, Occidental states the Commission should grant rehearing and modify ''market-regulated power sales affiliate'' to ''market-regulated power sales function'' which would necessitate removing the provision stating that such an entity is not a franchised public utility.[272]

Commission Determination

188. We deny Occidental's request for rehearing and clarification. As we explained in Order No. 697, we ''are concerned that there exists the potential for a franchised public utility with captive customers to interact with a market-regulated power sales affiliate in ways that transfer benefits to the affiliates and its stockholders to the detriment of the captive customers.'' [273] Accordingly, we have adopted in our regulations affiliate restrictions intended to guard against such behavior.

189. If an entity decides to encompass its marketing function within the franchised public utility's corporate structure, then there is no longer any affiliate entity to trigger the concerns of affiliate abuse that the market-based rate affiliate restrictions are designed to address. For example, one of our primary concerns in adopting affiliate restrictions is to prevent a franchised utility from making below-market sales to its merchant affiliate and to prevent the merchant affiliate from making above-market sales to its franchised utility affiliate.

In particular, Occidental's argument rests on the premise that the franchised public utility that encompasses its marketing function within the franchised public utility corporate structure could benefit its market-based rate activities at the expense of its captive customers. Occidental appears to be suggesting that revenues from the franchised public utility's off-system sales at market-based rates would be funneled to the utility's shareholders rather than credited to the utility's customers. However, such a scenario is at odds with Commission precedent requiring that off-system sales be reflected through allocation or revenue credits in the rates of the utility's customers.[274]

190. Additionally, state commissions have oversight authority for franchised public utilities with captive customers that make retail sales. Therefore, the states should be able to ensure that a franchised public utility with captive customers does not attempt any ''internal'' cross-subsidization to the detriment of captive customers. Generally, states similarly require revenue crediting to the utility's retail customers.

191. Thus, we will deny Occidental's request for rehearing and clarification and retain the current requirements for the affiliate restrictions. We will also retain the current definition of market-regulated power sales affiliate under Order No. 697.

c. Definition of Captive Customers

Final Rule

192. As adopted in Order No. 697, 18 CFR 35.36(a)(6) defines captive customer as ''any wholesale or retail electric energy customers served under cost-based regulation.'' [275] The Commission clarified that the definition of captive customers did not include those customers who have retail choice, *i.e.*, the ability to select a retail supplier based on the rates, terms, and conditions of service offered. Rather, retail customers who have no ability to choose an electric energy supplier are considered captive because they must purchase from the local utility pursuant to cost-based rates set by a state or local regulatory authority; that is, they are served under cost-based regulation.

193. The Commission further explained in Order No. 697 that retail customers who choose to be served under cost-based rates, even though they have the ability to choose one retail supplier over another, are not considered to be under ''cost-based regulation'' and therefore are not captive under the definition.

194. While much of the discussion in Order No. 697 focused on retail customers, the Commission stated ''regarding wholesale customers, sellers should continue to explain why, if they have wholesale customers, those customers are not captive.'' [276]

195. The Commission also declined to include transmission customers in the definition of captive customers for purposes of market-based rates for public utilities. The Commission stated that the open access policies in Order

[266] *Id.* at P 490.

[267] Occidental Rehearing Request at 2.

[268] *Id.*

[269] *Id.* at 5.

[270] *Id.* at 4.

[271] *Id.* at 8.

[272] *Id.*

[273] Order No. 697 at P 513.

[274] *See, e.g.*, *Public Service Co. of New Mexico*, Opinion No. 146, 20 FERC ¶ 61,290 at 61,546–48 (crediting revenue from intersystem opportunity sales to native load customers), *reh'g denied*, 21 FERC ¶ 61,334 (1982); *Golden Spread Electric Cooperative, Inc.*, Opinion No. 501, 123 FERC ¶ 61,047 at P 94–98 (crediting revenue from intersystem opportunity sales to native load customers) (2008); *Boston Edison Co.*, Opinion No. 53, 8 FERC ¶ 61,077 at 61,283 (allocating costs to firm services where the revenue crediting methodology may result in over-allocation of costs to the customers whose rates were at issue), *reh'g denied*, Opinion No. 53–A, 9 FERC ¶ 61,002 (1979).

[275] Order No. 697 at P 478 (to be codified at 18 CFR 35.36(a)(6)).

[276] Order No. 697 at P 480.

No. 890 protect transmission customers from the exercise of vertical market power.

Requests for Rehearing

196. Occidental argues that, just as with retail customers that have retail choice, wholesale customers with alternatives should also not be deemed to be ''captive customers.'' [277] Occidental argues that wholesale customers, whether buying under cost-based or market-based rates, have alternatives and are therefore not captive. Occidental states that a wholesale seller does not have any obligation to sell to any buyer, nor is a wholesale buyer obligated to buy from any particular seller. Occidental argues that the Commission's conclusion that retail customers with retail choice ''are not served under cost-based regulation, since that term indicates a regulatory regime in which retail choice is not available'' dictates that a wholesale cost-based customer cannot be captive because choice is, by definition, available.[278] Accordingly, Occidental requests that the Commission remove wholesale customers from the definition of captive customers.

Commission Determination

197. With regard to Occidental's request for rehearing concerning whether wholesale customers should be included in the definition of ''captive customers,'' we note that Occidental raised the same argument in its comments in the Affiliate Transactions rulemaking. In the course of responding to Occidental's concerns in that proceeding, the Commission provided a number of clarifications regarding the term ''captive customers,'' the purpose of the definition, and its focus on ''cost-based regulation'' that we reiterate here.

198. The Commission explained that its fundamental goal in categorizing certain customers as ''captive'' is to protect customers served by franchised public utilities from inappropriately subsidizing the market-regulated or non-utility affiliates [279] of the franchised public utility or otherwise being financially harmed as a result of affiliate transactions and activities. In other words, we are concerned about the potential for the inappropriate transfer of benefits from such customers to the shareholders of the franchised public utility or its holding company.[280] Where customers are served under market-based regulation as opposed to cost-based regulation, it is presumed that the seller has no market power over a customer and that the customer has a choice of suppliers; thus, there is less opportunity for a customer to involuntarily be in a situation in which its rates subsidize or support another entity.

199. Under a regime of cost-based regulation, however, we cannot make these same assumptions. If a franchised public utility is selling at a wholesale cost-based rate under the FPA, the franchised utility seller may be in the position of potentially trying to flow through its cost-based rates costs that should instead be borne by its affiliates, *i.e.*, potentially subsidizing the ''non-regulated'' activities of its market-regulated power sales affiliates to the detriment of the franchised public utility's customer(s). As the Commission stated in the Affiliate Transactions Final Rule, while there is some merit to Occidental's assertion that wholesale customers, by definition, have alternatives and that there is no obligation for a wholesale customer to sell to any buyer, nor for a buyer to buy from any particular seller, for the customer protection reasons stated above, we believe it is important to err on the side of a broad definition of captive customers. On this basis, we deny Occidental's request for rehearing that the Commission change its existing analysis and generically exclude wholesale customers from the definition of captive customers.

200. Nevertheless, as the Commission noted in the Affiliate Transactions Final Rule, although we are erring on the side of a broad definition of captive customers, we recognize that there may well be circumstances in which customers fall within our definition, even though there are sufficient protections in place to protect such customers against any risk of harm from transactions between the franchised public utility and its affiliates. For example, it is possible that wholesale customers with fixed rate contracts would be adequately protected and that the affiliate restrictions should not apply to utilities whose customers all have fixed rate contracts with no fuel adjustment clause.[281] The Commission explained that it is not prepared at this time to generically exclude such customers from the definition of captive customers but instead will allow franchised public utilities, on a case-by-case basis, to argue that the affiliate restrictions should not apply. This will allow the Commission to closely examine the facts related to each franchised public utility. There may be circumstances other than fixed rate contracts in which we may be willing to find that the affiliate restrictions do not apply, but a public utility will need to demonstrate that there is no opportunity for wholesale customers of the franchised public utility to be harmed as a result of affiliate transactions.

201. We note that in Order No. 697, we stated that ''regarding wholesale customers, sellers should continue to explain why, if they have wholesale customers, those customers are not captive.'' [282] Consistent with the foregoing discussion, we will modify that statement. If sellers have wholesale customers, instead of explaining why those customers are not captive, the sellers should explain why those customers are adequately protected against affiliate abuse.

202. We also will revise the definition of captive customers to be consistent with the definition adopted in the Affiliate Transactions Final Rule. In that Final Rule, the Commission modified the definition of captive customers to make explicit what was only implicit in its earlier rules—that the definition is intended to apply to customers served by a franchised public utility under cost-based regulation. Accordingly, we will revise the definition of captive customers in 18 CFR 35.36(a)(6) to mean ''any wholesale or retail electric energy customers served *by a franchised public utility* under cost-based regulation.''

203. Additionally, as the Commission recently stated in the Affiliate

[277] Occidental Rehearing Request at 9.

[278] *Id.*

[279] We note that the affiliate restrictions adopted in Order No. 697 apply to power sales and non-power goods and services transactions between franchised public utilities with captive customers and their market-regulated power sales affiliates, whereas the Affiliate Restrictions Final Rule applies to franchised public utilities with captive customers and their market-regulated power sales affiliates as well as their non-utility affiliates. Accordingly, the discussion herein is limited to market-regulated power sales affiliates.

[280] For example, if a market-regulated seller sells power to its affiliated franchised public utility at an above market price, the customers of the franchised public utility pay more than they need to for power and the affiliate makes a higher profit for the holding company's shareholders. Similarly, if a franchised public utility sells temporarily excess fuel to its market-regulated power seller affiliate at a price below its cost, the customers of the franchised utility end up subsidizing the affiliate's operating costs, to the benefit of shareholders and the detriment of the customers of the franchised utility. In other contexts, an extreme example would be a holding company that siphons funds from a franchised public utility to support its failing market-regulated power sales affiliate company; again, this results in financial benefit to shareholders at the expense of customers.

[281] The Commission would need to be assured that all wholesale customers of a franchised public utility have adequate fixed rate contracts, not just a sub-set of the customers. Further, because such contracts may have different expiration dates, the Commission might need to place temporal conditions on such a waiver.

[282] Order No. 697 at P 480.

Transactions Final Rule, if a state regulatory authority in a retail choice state does not believe that retail customers are sufficiently protected and that our affiliate restrictions should apply to the local franchised public utility, it may file a petition for declaratory order to deem its retail customers to be captive customers for purposes of applying the affiliate restrictions.[283] A state regulatory authority may also raise such an argument as part of its comments in a market-based rate proceeding.

d. Electric Cooperatives

Final Rule

204. The Commission declined to subject to the affiliate restrictions and regulations in § 35.39 electric cooperatives that may otherwise be subject to the Commission's jurisdiction. In Order No. 697, the Commission reasoned that ''affiliate abuse takes place when the affiliated public utility and the affiliated power marketer transact in ways that result in a transfer of benefits from the affiliated public utility (and its ratepayers) to the affiliated power marketer (and its shareholders).'' [284] The Commission explained that, where a cooperative is involved, the cooperative's members are both the ratepayers and the shareholders. Therefore, there is no potential danger of shifting the benefits from the ratepayers to the shareholders.[285]

Requests for Rehearing

205. El Paso E&P argues that the Commission's concerns regarding affiliate transactions should apply equally to sales by jurisdictional public utility cooperatives to their affiliated members,[286] and that the Commission cannot abdicate its obligation to protect captive customers. According to El Paso E&P, the fact that a cooperative is comprised of its member distribution cooperatives could actually facilitate the exercise of market power, because a cooperative, through its member board, has an incentive to charge as much as it can to captive customers in order to subsidize the rates paid by its residential and commercial customers.[287]

206. El Paso E&P contends that the Commission abdicated its responsibility under the FPA to protect captive customers by claiming lack of jurisdiction over the cooperatives.[288] El Paso E&P explains that no Commission precedent addresses the situation where sales at market-based rates are ultimately made to captive customers of the distribution cooperatives. El Paso E&P points out that, unlike other cases, a generation and transmission cooperative seller's affiliate distribution cooperatives are not the ultimate consumers of the power.[289] Therefore, El Paso E&P maintains, they do intend to pass on potential excessive purchased power costs to captive customers.

207. For example, El Paso E&P argues that the fact that Deseret and Moon Lake may receive above-market rates from El Paso E&P will not necessarily result in profit to either entity. Rather, the collection of such monopoly rents could be used by either Deseret or Moon Lake to subsidize the costs paid by other ratepayers in their members' franchised service territories. Even if it did result in profits to either Deseret or Moon Lake, El Paso E&P asserts that there is no assurance that El Paso E&P would receive any share of such profits since it is not a member of Deseret's board and has no say in what Deseret charges to its members. Because it also is not a member of Moon Lake's board, El Paso E&P argues it has no ability to vote on whether any profits that may be earned by Deseret, and may be credited to Moon Lake, are actually paid back to it.[290]

208. El Paso E&P also argues that the Commission erred in justifying its failure to protect captive ratepayers of cooperatives on the ground that El Paso E&P's concern is really about discrimination in the allocation of benefits and burdens among retail ratepayers, which is a state law issue. El Paso E&P argues that this cannot be squared with the protection that the Commission provides in Order No. 697 for captive ratepayers of non-cooperative sellers.[291] El Paso E&P takes the position that, if the Commission permits cooperatives to charge market-based rates, then the Commission is obligated to ensure that all captive customers are protected from any abuse or excessive rates resulting from those market-based rates.[292]

209. Moreover, El Paso E&P argues that the Commission has not explained how state commissions could deny pass-through of market-based rates by distribution cooperatives to their retail customers when the rates have been approved by the Commission.[293] It asserts that the cases cited by the Commission are not on point. Specifically, the exception to federal pre-emption discussed in *Nantahala Power and Light Co.* v. *Thornburg*[294] relates to the quantity purchased, not the price paid. El Paso E&P contends that this exception is not applicable to cooperatives because their cooperative structure requires the distribution cooperative members to purchase their power from their generation and transmission cooperative.[295]

Commission Determination

210. We deny El Paso E&P's request for rehearing. El Paso E&P has not raised any new arguments on rehearing, and it has not persuaded us to reverse our finding from Order No. 697 that electric cooperatives are not subject to the Commission's affiliate restrictions codified in § 35.39.

211. The Commission explained in Order No. 697 that, even if an electric cooperative is not exempt from public utility regulation by the FPA under section 201(f), the Commission previously determined that transactions of an electric cooperative with its members do not present dangers of

[283] Affiliate Transactions Final Rule at P 45.

[284] Order No. 697 at P 526 (citing *Heartland Energy Services, Inc.,* 68 FERC ¶ 61,223, at 62,062 (1994)).

[285] Order No. 697 at P 526 (citing *Old Dominion Electric Cooperative,* 81 FERC ¶ 61,044, at 61,236 (1997)).

[286] El Paso E&P Rehearing Request at 8 (citing *Illonova Power Marketing, Inc.,* 88 FERC ¶ 61,189 (1999); *First Energy Trading & Power Marketing, Inc.,* 84 FERC ¶ 61,214 (1998)).

[287] *Id.* at 6, 12.

[288] *Id.* at 6.

[289] *Id.* at 11.

[290] *Id.* at 12–13.

[291] *Id.* at 14.

[292] *Id.* at 8.

[293] *Id.* at 7, 15 (citing *Arkansas Power & Light Co.* v. *Missouri Public Service Commission,* 829 F.2d 1444, 1452–53 (8th Cir. 1987)) (Arkansas P&L) (holding that the ordinary state-law process of suspension and investigation of retail rates is not preempted by the FPA ,and there is no language in the FPA to indicate that Commission orders on wholesale rates require an immediate pass-through of those wholesale rates).

[294] 476 U.S. 953 (1986). *Mississippi Power & Light Co.* v. *Mississippi ex rel. Moore,* 487 U.S.354 (1958) (holding that state commissions must treat Commission-approved costs for wholesale power as reasonably incurred operating expenses for the purposes of setting retail rates, but state commissions are precluded from setting retail rates that would ''trap'' the costs a seller was mandated to pay under a Commission order, or from undertaking a prudence review for the purpose of deciding whether to approve such retail rates.); *Central Vermont Public Service Corporation,* 84 FERC ¶ 61,194 (1998)) (holding that state commissions are preempted by federal law from reviewing the prudence of power purchases, if, as a result of wholesale power supply allocation directed by the Commission, the purchaser has no legal choice but to make a particular purchase and to permit such a review would interfere with the Commission's plenary authority over interstate wholesale rates).

[295] *Id.*

affiliate abuse through self-dealing.[296] Where a cooperative is involved and the cooperative's members are both the ratepayers and the shareholders, any profits earned by the cooperative will inure to the benefit of the cooperative's ratepayers. As such, no potential danger exists of shifting benefits from the ratepayers to the shareholders. Deseret is not a for-profit entity with an incentive to maximize its rates for the benefit of its shareholders; rather, its ratepayers and shareholders are the same entities. Similarly, Moon Lake is not a power marketer concerned only with passing its costs through to its ratepayers for the benefit of its shareholders. Rather, Moon Lake is responsible to its members, including El Paso E&P, which is entitled to vote in Moon Lake's Board elections and is entitled to the same single vote held by each residential and commercial ratepayer of Moon Lake.[297]

212. Moreover, if Deseret charges Moon Lake higher rates than Deseret charges its other five member cooperatives, it may be engaging in discrimination, which is barred by sections 205 and 206 of the FPA. As we explained in Order No. 697, El Paso E&P's concern is not one that can be addressed through affiliate restrictions in market-based rates, but is rather more of a concern of discrimination in the allocation of benefits and burdens among retail ratepayers.[298]

213. Therefore, we deny El Paso E&P's request for rehearing and reaffirm our finding that electric cooperatives are not subject to the affiliate restrictions codified in § 35.39 because there is no danger of affiliate abuse through self-dealing.

e. Public Utility Holding Company Act of 2005 as a ''Commission Rule or Order'' Permitting At-Cost Pricing

Final Rule

214. Order No. 697 requires that sales of any non-power goods or services by a market-regulated power sales affiliate to an affiliated franchised public utility with captive customers will not be at a price above market, unless otherwise permitted by Commission rule or order.[299] The Commission also adopted the proposal to require that sales of non-power goods or services by a franchised public utility with captive customers to a market-regulated power sales affiliate be at the higher of cost or market price, unless otherwise authorized by the Commission. The Commission explained that these requirements will protect captive customers against affiliate abuse by ensuring that the utility with captive customers does not recover too little for goods and services provided to a market-regulated power sales affiliate and that the franchised public utility with captive customers does not pay too much for goods and services provided by a market-regulated power sales affiliate.[300]

Requests for Rehearing

215. EEI states that the Final Rule requires market-regulated affiliates to sell non-power goods and services to utilities with captive customers at or below market prices, unless otherwise authorized by the Commission. It seeks rehearing of the Final Rule as that requirement may apply to centralized service companies.[301] Specifically, EEI notes that in Order No. 667, the Commission issued a final rule implementing the Public Utility Holding Company Act of 2005, with a rebuttable presumption that centralized service companies may use ''at cost'' pricing for services to affiliate utilities, unless complainants demonstrate that the at-cost pricing exceeds the market price.[302] EEI requests that the Commission clarify that Order No. 667 constitutes a ''Commission rule or order'' generally authorizing use of at-cost pricing by centralized service companies to utility affiliates under Order No. 697, absent complainant evidence that such pricing exceeds the market price.[303]

Commission Determination

216. We will grant EEI's request and clarify that Order No. 667 constitutes a Commission rule or order generally authorizing the use of at-cost pricing by a centralized service company to utility affiliates absent any demonstration that at-cost pricing exceeds the market price.

217. In Order No. 667, the Commission allowed centralized service companies to sell non-power goods and services to affiliated franchised utilities using an ''at cost'' standard, stating that ''there is a rebuttable presumption that such 'at-cost' sales for non-power goods and services between a centralized service company and its affiliates are reasonable.''[304] The Commission made clear that the rebuttable presumption for ''at-cost'' sales for non-power goods and services only applies to sales by a centralized service company to its affiliates. Sales of non-power goods and services made by market regulated or unregulated affiliates other than centralized service companies to their franchised utility affiliates are subject to the Commission's ''no higher than market'' standard.[305] The Commission also explained that while it will apply a rebuttable presumption that costs incurred under ''at-cost'' pricing for services provided by centralized service companies are reasonable, the Commission will entertain complaints that ''at-cost'' pricing for such services exceeds the market price.[306]

218. Given the Commission's reasoning set forth in Order No. 667 and Order No. 667–A, we clarify that, for centralized service companies, as defined in Order No. 667 and § 366.5 of the Commission's regulations, Order No. 667 constitutes a ''Commission rule or order'' generally authorizing use of at-cost pricing by centralized service companies to their franchised public utilities with captive customers, absent complainant evidence that such at-cost pricing exceeds the market price.

f. Sales of Non-Power Goods and Services

Final Rule

219. In Order No. 697, the Commission held that sales of non-power goods or services by a franchised public utility with captive customers to a market-regulated power sales affiliate are to be at the higher of cost or market price, unless otherwise authorized by the Commission. The Commission also codified the requirement that sales of any non-power goods or services by a market-regulated power sales affiliate to an affiliated franchised public utility with captive customers will not be at a price above market, unless otherwise authorized by the Commission.[307]

Requests for Rehearing

220. FP&L seeks limited clarification or, in the alternative, reconsideration of Order No. 697 on the issue of pricing of non-power goods and services provided for affiliates by either franchised public utilities or their market-regulated power sales affiliates when those services are

[296] Order No. 697 at P 526 (citing *Heartland Energy Services, Inc.,* 68 FERC ¶ 61,223, at 62,062 (1994)).

[297] *See* El Paso E&P Rehearing Request at 13, n.7.

[298] Order No. 697 at P 527.

[299] *Id.* at P 597; 18 CFR 35.39(e).

[300] *Id.*

[301] EEI Rehearing Request at 2.

[302] *Repeal of the Public Utility Holding Company Act of 1935 and Enactment of the Public Utility Holding Company Act of 2005,* Order No. 667, FERC Stats. & Regs. ¶ 31,197, at P 169 (2005), *order on reh'g,* Order No. 667–A, FERC Stats. & Regs. ¶ 31,213, *order on reh'g,* Order No. 667–B, FERC Stats. & Regs. ¶ 31,224 (2006), *order on reh'g,* Order No. 667–C, 118 FERC ¶ 61,133 (2007).

[303] EEI Rehearing Request at 4, 7–8.

[304] Order No. 667–A, FERC Stats. & Regs. ¶ 31,213 at P 38.

[305] *Id.*

[306] Order No. 667, FERC Stats. & Regs. ¶ 31,197 at P 169.

[307] Order No. 697 at P 597 (to be codified at 18 CFR 35.39(e)).

comparable to shared services provided by a centralized service company.

221. FP&L requests clarification that when a franchised public utility provides its market-regulated power sales affiliates with non-power goods or services, or a market-regulated power sales affiliate provides its affiliated franchised public utility with non-power goods and services, and those services are comparable to those provided by a centralized service company, then those non-power goods and services may be provided at fully-loaded cost as a reasonable proxy for market price.[308] FP&L also requests that the Commission clarify that the grandfathering provision in the Affiliate Transactions Final Rule (which provides that the pricing rules adopted therein are prospective only) also applies with respect to the requirements of Order No. 697 where existing inter-affiliate transactions involving non-power goods and services are comparable to those provided by a centralized service company.

Commission Determination

222. Issues similar to those raised here by FP&L also have been raised on rehearing of the Affiliate Transactions Final Rule, which applies the same standards for the pricing of non-power goods and services as Order No. 697. To ensure consistency in our approach to pricing of non-power goods and services between both rulemaking proceedings, the Commission will address FP&L's arguments concerning Order No. 697 in a supplemental order.[309]

2. Power Sales Restrictions

a. Sales Between Two Affiliates Requiring Prior Commission Approval

Final Rule

223. In paragraph 467 of the Final Rule, the Commission stated that it was adopting in the regulations a provision expressly prohibiting power sales between a franchised public utility with captive customers and any market-regulated power sales affiliates without first receiving Commission authorization for the transaction under section 205 of the FPA.[310]

224. The Commission further noted (in paragraph 492) that while it has historically placed affiliate restrictions only on the relationship between a franchised public utility with captive customers and any affiliated market-regulated power sales affiliate, the Commission believes there may be circumstances in which it also would be appropriate to impose similar restrictions on the relationship of two affiliated franchised public utilities where one of the affiliates has captive customers and one does not. The Commission said it would not generically impose the affiliate restrictions on such relationships but will evaluate whether to impose the affiliate restrictions in such situations on a case-by-case basis.[311]

Requests for Rehearing

225. Ameren argues that paragraphs 467 and 492 of Order No. 697, taken together, provide that power sales between two affiliated franchised public utilities—one with captive customers and one without—are not prohibited, do not require prior authorization under section 205 of the FPA, and are not generally subject to the affiliate restrictions. Instead, the Commission said that it will consider applying the restrictions on a case-by-case basis.[312] Given that position, Ameren is confused by § 35.39(h) of the new regulations, which provides:

> *If necessary*, any affiliate restrictions regarding separation of functions, power sales or non-power goods and services transactions, or brokering involving two or more franchised public utilities, one or more of whom has captive customers and one or more of whom does not have captive customers, will be imposed on a case-by-case basis. [313]

226. Ameren states this provision is meaningless if prior authorization of such transactions is not required. With regard to the Commission's statement that it will consider applying the affiliate restrictions on a case-by-case basis, Ameren states that the Commission fails to explain how it will conduct such an analysis of the need to apply the restriction or when such an obligation to abide by this particular restriction would arise.

227. Ameren states that the Commission should do one of three things. Because the Commission itself noted that commenters did not show a potential for affiliate abuse in such a situation, the Commission could clarify, consistent with precedent, that prior authorization of power sales between affiliated franchised public utilities is not required and therefore § 35.39(h) will be deleted. Alternatively, the Commission could clarify that, absent a specific finding imposed prospectively under sections 205 or 206 of the FPA, a utility has no obligation to seek prior authorization of power sales between affiliated franchised public utilities. Conversely, Ameren maintains that, if the Commission intends that public utilities seek pre-approval of such transactions, then it should clearly state that intention. Without such clarification, Ameren asserts that franchised public utilities face an uncertain regulatory regime when transacting with another franchised public utility.[314]

Commission Determination

228. In response to Ameren's request, we clarify that when a franchised public utility receives section 205 authority to sell at market-based rates, it does not have to obtain a separate section 205 authority for power sales to another franchised public utility, as would be the case if it wanted to make power sales to a non-franchised, market-regulated power sales affiliate. Thus, an additional authorization is not required for power sales between two affiliated franchised public utilities, one with captive customers and one without captive customers. We clarify that, when we said we would evaluate these situations on a case-by-case basis, we meant that the Commission, on its own motion or in response to a complaint, may decide to examine the circumstances of any power sales between two such affiliated franchised public utilities, where one has captive customers and the other does not. Any determination based on such an examination would be prospective only.

b. Affiliate Restrictions' Applicability to Franchised Public Utilities and Commission Jurisdictional Market-Regulated Power Sales Affiliates

Final Rule

229. The Commission explained in Order No. 697 that the market-based rate affiliate restrictions codified in § 35.39 govern the relationship between a franchised public utility with captive customers and its market-regulated power sales affiliates. This ensures that captive customers are protected from any potential for harm as a result of affiliate dealings.

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[308] FP&L March 24, 2008 Request for Clarification at 4.

[309] The Commission need not address all issues raised in a proceeding at one time. *See Mobil Oil Exploration & Producing Southeast, Inc.* v. *United Distribution Companies,* 498 U.S. 211 (1991) (holding that an agency enjoys broad discretion in determining procedurally how best to handle related yet discrete issues). *See also Colorado Office of Consumer Counsel* v. *FERC,* 490 U.S. 954 (D.C. Cir. 2007) (holding that the Commission need not revisit all elements of a tariff upon finding one aspect to be unjust and unreasonable).

[310] Order No. 697 at P 467.

[311] *Id.* P 492.

[312] Ameren Rehearing Request at 5.

[313] Emphasis added.

[314] *Id.* at 6.

Requests for Rehearing

230. FP&L states that it remains unclear whether the restrictions are intended to cover non-franchised power marketers whose sales are not subject to Commission jurisdiction—for example power marketers selling exclusively into the Electric Reliability Counsel of Texas (ERCOT).[315] FP&L requests that the Commission clarify that the affiliate restrictions apply only to the relations between franchised public utilities with captive customers and their Commission-jurisdictional market-regulated power sales affiliates, and do not apply to affiliates engaged in power sales exclusively within ERCOT.[316] FP&L states that, given the magnitude of an expansion of the affiliate restrictions to cover non-Commission-jurisdictional power marketers, and the absence of any explicit discussion in either the proposed rule or the Final Rule in this proceeding, FP&L does not believe the Commission intends such an expansion.[317]

Commission Determination

231. We grant in part FP&L's request for clarification. The Commission's market-based rate regulations, including the affiliate restrictions, do not apply to entities that are not considered public utilities under FPA section 201(e), which would include entities engaged in power sales exclusively within ERCOT.

232. The Commission's market-based rate regulations apply to any public utility with market-based rates. If a franchised public utility with market-based rates sells to an affiliate company in ERCOT (which would be a non-public utility), the affiliate restrictions would apply to the franchised public utility's dealings with the affiliate. It could not sell to or purchase from the ERCOT affiliate unless consistent with our regulations. The affiliate restrictions would not apply to the ERCOT affiliate's dealings with the other non-public utility affiliates since the ERCOT affiliate is not a public utility.

3. Market-Based Rate Affiliate Restrictions

233. In codifying the affiliate restrictions in the regulations, the Commission established certain restrictions that govern the separation of functions, sharing of market information, sales of non-power goods or services, and power brokering to govern the relationship between franchised public utilities with captive customers and their market-regulated affiliates. As a condition of receiving and retaining market-based rate authority, the Commission required sellers to comply with these affiliate restrictions unless otherwise permitted by Commission rule or order.[318]

a. Two-Way Information Sharing Restriction

Final Rule

234. The Commission adopted a two-way information sharing restriction in § 35.39(d) prohibiting a franchised public utility with captive customers from sharing information with a market-regulated power sales affiliate, and vice-versa.[319]

Requests for Rehearing

235. Southern argues the Commission erred in Order No. 697 by adopting a two-way information restriction (§ 35.39(d)) that prevents a franchised public utility from receiving information from its market-regulated power sales affiliate. Southern claims that the Commission failed to demonstrate that communications from a market-regulated power sales affiliate to a franchised public utility would harm captive customers and that the existing one-way communication restriction currently in many Commission-accepted codes of conduct is insufficient.

236. Southern states that the Commission provided one example of how information shared with a franchised public utility by its market-regulated affiliate might harm captive customers. Specifically, the Commission stated that in an RFP situation where both a franchised public utility and its market-regulated affiliate are considering whether to submit a bid and the market-regulated affiliate is allowed to share its price and quantity information, the franchised public utility could possibly use the information for the benefit of its stockholders at the expense of its captive customers. However, Southern submits that § 35.39(d) is written much broader than is necessary to address this concern, and could serve to unnecessarily prevent a franchised public utility from receiving operational information under Commission-approved generation pooling arrangements. Southern argues that the Commission has not suggested much less demonstrated that a franchised public utility's knowledge of the status of its market-regulated affiliate's units could advantage the market-regulated affiliate at the expense of the franchised public utility's captive customers. Accordingly, Southern alleges Order No. 697 is without a rational basis in this regard and unsupported by substantial evidence.[320]

237. Southern believes that the two-way restriction would actually harm captive customers by impairing the pooling arrangement, thereby denying them the traditional benefits of integration and coordinated operations and by triggering costs and inefficiencies that far outweigh any conceivable benefit. Accordingly, Southern requests that the Commission reconsider the two-way information sharing restriction.

238. Moreover, according to Southern, the Commission failed to recognize the implementation burden that will be imposed by the two-way restriction. Southern submits that the Commission has grossly underestimated the expense and effort that will be required for utilities to implement the two-way restriction.[321] Based on its actual experience, Southern believes that compliance with the two-way restriction will be very costly to utilities and require a substantial amount of time to complete, potentially in excess of six months (a much longer period than is allowed by an effective date of 60 days after the Final Rule's publication in the **Federal Register**).[322] While some utilities may be able to complete their implementation of the two-way restriction within this period, Southern argues it is more likely that most utilities will need more time to ensure compliance. Thus, to the extent the Commission maintains the two-way restriction, Southern requests that the Commission allow utilities and their market-regulated power sales affiliates sufficient time to implement the two-way restriction.[323]

239. To the extent the Commission maintains the restriction, in any form, Southern requests that the Commission clarify the scope of § 35.39(d) and limit the types of information that are

[315] FP&L Rehearing Request at 11.

[316] *Id.* at 10, 12.

[317] *Id.* at 12.

[318] Order No. 697 at P 549. To the extent that the Commission did not impose a code of conduct requirement on a seller as a condition of market-based rate authority because the seller had demonstrated that it did not have captive customers, that waiver remains in effect provided that the seller still does not have captive customers.

[319] *Id.* P 583.

[320] Southern Rehearing Request at 6 (citing *Motor Vehicles Mfrs. Ass'n.*, 463 U.S. at 43 (1983) (stating that the agency must articulate a ''rational connection between the facts found and the choice made''); *Burlington Truck Lines* v. *U.S.*, 371 U.S. 156, 168 (1962); *Western Union* v *FCC*, 856 F.2d 315, 318 (D.C. Cir. 1988) (stating that an agency must demonstrate a ''rational connection between the facts found and the choice made'')).

[321] *Id.* at 37.

[322] Order No. 697 at P 1133.

[323] Southern Rehearing Request at 36, 39.

restricted to be consistent with the above-described example set forth in Order No. 697.[324] Southern states that, at a minimum, the Commission should provide an exception for information provided to franchised public utilities by their market-regulated affiliate pursuant to participation in Commission-approved pooling arrangements. Finally, and to the extent the Commission retains any two-way restrictions, it should allow franchised public utilities and their market-regulated power sales affiliates sufficient time to assess their organizations and technology infrastructures and implement the measures necessary to ensure compliance.[325]

Commission Determination

240. After consideration of Southern's arguments, we will grant Southern's request for rehearing on this issue.

241. As previously explained, the purpose of the affiliate restrictions is to ensure that captive customers of a franchised public utility are adequately protected from any harm that may arise from affiliate dealings. In an attempt to provide regulatory certainty, and upon further review, we find that the one-way information sharing restriction, which prohibits a franchised public utility with captive customers from sharing market information with a market-regulated power sales affiliate, adequately protects captive customers. We have not been presented with any specific examples of how captive customers have been harmed by a market-regulated power sales affiliate sharing market information with its franchised public utility with captive customers. We also note that adopting a one-way information sharing restriction is consistent with the Commission's approach in the Standards of Conduct.

242. While we are granting Southern's request for rehearing on this issue, we remind sellers that the information sharing provision, like all affiliate restrictions, is subject to the no-conduit rule. The no-conduit rule allows permissibly-shared employees to receive market information so long as they are not conduits for sharing that information with employees that are not permissibly shared. Additionally, we remind all market-based rate sellers that the FPA prohibits any seller from providing an undue preference to an affiliate or any other seller.[326]

b. Affiliate Restrictions' Precedence Over Pre-Existing Codes of Conduct

Final Rule

243. As stated above, the Commission expressly stated in Order No. 697 that the regulations at 18 CFR part 35, Subpart H, including the affiliate restrictions, will become effective 60 days after publication of Order No. 697 in the **Federal Register**.[327] Order No. 697 became effective on September 18, 2007.

Requests for Rehearing

244. Ameren asserts that a reasonable interpretation of Order No. 697 is that sellers with market-based rate authority are to follow the affiliate restrictions in § 35.39 upon the effective date of the regulation, but states nothing is said regarding the potential for conflicts between the new regulations and existing affiliate restrictions/codes of conduct and how such conflicts will be resolved. Ameren states that the Commission apparently intended the new regulations to supersede the existing affiliate restrictions/codes of conduct, but asserts that clarification is needed. Thus, in order to avoid uncertainty and increase transparency, Ameren asks the Commission to clarify whether the new regulations take precedence over the affiliate restrictions/codes of conduct currently on file upon the effective date of the new regulations.[328]

Commission Determination

245. The Commission clarifies that the new affiliate restriction regulations promulgated in Order No. 697 and codified in § 35.39 supersede the codes of conduct approved by the Commission prior to Order No. 697's effective date.[329] The affiliate restrictions in § 35.39 now govern the relationship between a franchised public utility with captive customers and its market-regulated power sales affiliates. In the event of a conflict between a seller's previously approved code of conduct and the new affiliate restriction regulations, the regulations supersede a previously approved code of conduct. For example, if a seller's previous code of conduct prohibited information sharing of any market information, public or non-public, because the definition of market information in the regulations does not prohibit the disclosure of publicly available information, a seller may share public market information under the new affiliate restrictions.[330]

246. Nevertheless, where the Commission had imposed in a Commission order in a particular case specific limitations that are more restrictive than those codified in § 35.39, such limitations would continue to be in effect. We also clarify that, while all sellers with market-based rate authority must abide by the affiliate restrictions as set forth in § 35.39 of the Commission's regulations, if a seller wishes to impose a more restrictive limitation than currently exists in the affiliate restrictions, such seller may propose additional tariff provisions for the Commission to review in a filing under FPA section 205.

c. Treatment of ''Field & Maintenance'' Employees and Shared Operation and Maintenance Staff in Affiliate Restrictions

Final Rule

247. In the Final Rule, the Commission codified in its regulations the requirement that, to the maximum extent practical, the employees of a market-regulated power sales affiliate must operate separately from the employees of any affiliated franchised public utility with captive customers (independent functioning requirement). The Commission adopted an exception to the independent functioning requirement that permits a franchised public utility with captive customers and its market-regulated power sales affiliates to share senior officers and members of the board of directors, support employees, and field and maintenance employees that perform purely manual, technical, or mechanical duties and do not have planning or direct operational responsibilities.[331]

Requests for Rehearing

248. FP&L states that certain of these changes and refinements to the affiliate restrictions (formerly code of conduct) appear subject to interpretation, and certain interpretations may be more restrictive than intended.[332] Specifically, FP&L states the Commission should clarify that ''field and maintenance employees'' include technical and engineering personnel engaged in generation-related activities, provided that such employees do not themselves: (1) Buy or sell energy; (2) make economic dispatch decisions; (3) determine (as opposed to implement) outage schedules; or (4) engage in power

[324] *Id.* at 39.

[325] *Id.* at 40–41.

[326] *See* 16 U.S.C. 824d (2001).

[327] *Id.* at P 924.

[328] Ameren Rehearing Request at 7.

[329] Clarification Order, 121 FERC ¶ 61,260 at P 5.

[330] *See id.* P 592.

[331] *Id.* P 561–63, 565; 18 CFR 35.39(c)(2)(ii).

[332] FP&L Rehearing Request at 2, 4.

marketing activities.[333] FP&L states that sharing such employees does not diminish or jeopardize the requirement of separation of functions ''to the maximum extent practical,'' and is ''unlikely to harm captive customers.'' [334]

249. Additionally, FP&L urges that the Commission clarify that ''field and maintenance employees'' include non-commercial technical and engineering personnel involved in nuclear plant operations.[335] FP&L notes that, in the context of nuclear plant operations, adherence to Nuclear Regulatory Commission (NRC) requirements and safe operations in general often are facilitated by the creation of a broad knowledge pool using all of a company's personnel with expertise in nuclear operations.[336]

250. EEI notes that Order No. 697 allows franchised public utilities with captive customers and their market-regulated power sales affiliates to share field and maintenance employees and their supervisors, but that it conditions this allowance on the employees and supervisors not exercising ''control'' over generation facilities.[337] If interpreted broadly, EEI argues this condition could eliminate the ability to share such staff that work on generation facilities, because operation and maintenance of generation facilities necessarily involve the ability to curtail or stop operation of the facilities. EEI requests that the Commission clarify that companies may share such employees and supervisors even if the employees and supervisors have the authority to curtail or stop the operation of generation facilities as part of their operation and maintenance functions, so long as the employees are not involved in decisions regarding the marketing or sale of electricity from the facilities.[338]

Commission Determination

251. We grant FP&L's request for clarification that ''field and maintenance employees'' includes technical and engineering personnel engaged in generation-related activities, provided that such employees do not themselves: (1) Buy or sell energy; (2) make economic dispatch decisions; (3) determine (as opposed to implement) outage schedules; or (4) engage in power marketing activities.

252. We have no evidence that such field and maintenance employees have engaged in behavior that would adversely affect captive customers. Additionally, we note that such field and maintenance employees are still subject to the no-conduit rule. Based on the evidence before us, the existing regulations and the overarching purpose of the affiliate restrictions, we find that excepting field and maintenance employees from the independent functioning requirement, provided such employees do not engage in prohibited actions as outlined above, is consistent with the affiliate restrictions. This clarification also is applicable to FP&L's request regarding shared employees involved in nuclear plant operations.[339]

253. In response to EEI's request for clarification, although Order No. 697 states that operational employees may not be shared, the Commission clarifies that companies may share employees and supervisors who have the authority to curtail or stop the operation of generation facilities solely for operational reasons. However, shared employees may not be involved in decisions regarding the marketing or sale of electricity from the facilities, may not make economic dispatch decisions, and may not determine the timing of scheduled outages for facilities. The Commission did not create the exception for permissibly-shared field and maintenance employees to enable those employees to confer a benefit on a franchised power utility's market regulated power sales affiliate to the detriment of captive customers. Thus, to ensure that captive customers are not harmed, shared field and maintenance employees may not make economic dispatch decisions or determine when scheduled maintenance outages (as opposed to emergency forced outages) will occur.

d. Risk Management Employees Under the No-Conduit Rule

Final Rule

254. With regard to the independent functioning requirement in the affiliate restrictions, the Commission adopted a ''no-conduit rule'' that prohibits a franchised public utility with captive customers and a market-regulated power sales affiliate from using anyone, including asset managers, as a conduit to circumvent the affiliate restrictions.[340] Otherwise, Order No. 697 did not specifically address the sharing of risk management employees.

Requests for Rehearing

255. FP&L requests that the Commission clarify that, subject to the no-conduit rule, risk management employees may permissibly be shared under the affiliate restrictions.[341] FP&L states that, while it does not believe Order No. 697 establishes a prohibition against shared risk management employees, in the absence of an explicit reference to risk management in § 35.39(c)(2)(ii), Order No. 697 has created confusion.[342]

Commission Determination

256. We find that risk management personnel do not fall within the scope of the independent functioning rule, so long as they are acting in their roles as risk management personnel rather than as marketing function employees, as defined in the standards of conduct. Of course, such risk management employees remain subject to the no-conduit rule and may not pass market information to marketing function employees.[343]

e. Definition of ''Market Information''

Final Rule

257. In Order No. 697, the Commission adopted a definition of market information: ''non-public information related to the electric energy and power business including, but not limited to, information regarding sales, cost of production, generator outages, generator heat rates, unconsummated transactions, or historical generator volumes.'' [344] The Commission explained that market information includes information that, if shared between a franchised public utility and a market-regulated affiliate, could result in a detriment to the franchised public utility's captive customers.[345]

Requests for Rehearing

258. Ameren argues that, in introducing its new definition of ''market information,'' for purposes of the restrictions on affiliates sharing

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[333] *Id.* at 3, 6–7.

[334] *Id.* at 6.

[335] *Id.* at 7.

[336] *Id.*

[337] EEI Rehearing Request at 5 (citing Order No. 697 at P 565).

[338] EEI Rehearing Request at 3–4 and 5–6.

[339] Order No. 697 permits the sharing of information to enable nuclear power plants to comply with the requirements of the NRC as described in the NRC's February 1, 2006 Generic Letter 2006–002, Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power. Order No. 697 at P 581.

[340] Order No. 697 (to be codified at 18 CFR 35.39(g)).

[341] FP&L Rehearing Request at 8.

[342] *Id.* at 10.

[343] *See Standards of Conduct for Transmission Providers*, Notice of Proposed Rulemaking, 73 FR 16,228 (March 27, 2008), FERC Stats. & Regs. ¶ 32,630 (March 21, 2008) (Standards of Conduct NOPR).

[344] Order No. 697 at P 591 (to be codified at 18 CFR 35.36(a)(8)).

[345] *Id.* P 593.

information, the Commission incorrectly quotes from its 1996 order in *UtiliCorp United, Inc.*[346] Specifically, Ameren alleges that the Commission recited the list of types of data from *UtiliCorp*, but added ''past'' to the litany. According to Ameren, this ''misquote'' sets the stage for the new definition to include past information, such as ''historical generator volumes'' and ''past sales and purchase activities.'' Ameren requests rehearing of this expansion of the definition of the term ''market information'' to include past information. In addition, Ameren states that the Commission does not explain how past information, such as historical generator volumes, could be used to the detriment of the franchised public utility's captive customers.[347]

Commission Determination

259. The Commission denies Ameren's request for rehearing. The Commission is intentionally including past market information in the information disclosure prohibitions because there are instances in which the sharing of historical (or past) market information between a franchised public utility with captive customers and a market-regulated power sales affiliate can potentially harm captive customers. For example, if a market-regulated power sales utility had knowledge of its affiliated franchised public utility's prior costs of purchasing power, it could use this information to outbid a competitor in a request for proposals to supply power to the franchised public utility. We note, however, that the restriction on sharing market information, whether past, present, or future, does not apply to information that is publicly available.[348]

D. Mitigation

1. Cost-Based Rate Methodology

a. Selecting the Particular Units that Form the Basis of the ''Up To'' Rate

Final Rule

260. Where a seller adopts the default cost-based mid-term rate or otherwise proposes a cost-based rate designed on the unit or units expected to run, the Final Rule continues to allow the seller flexibility in proposing the particular units that form the basis of the ''up to'' rate. The Commission determines whether such proposals are just and reasonable on a case-by-case basis. The Final Rule also reiterated that any seller proposing an alternative mitigation methodology carries the burden of justifying its proposal.[349]

Requests for Rehearing

261. TDU Systems and NRECA suggest that allowing sellers to choose the unit or units expected to run can affect the ''up to'' default rate for mid-term sales, and also skew the default incremental cost rate for short-term sales.[350] TDU Systems[351] and NRECA[352] claim that the Final Rule failed to adopt measures to ensure that the mitigated rates of large public utilities reflect their actual cost of service. TDU Systems and NRECA submit that the Commission should adopt more stringent controls over sellers' discretion in establishing cost-based rates for mid-term sales in markets where a seller has been found, or is presumed, to have market power.[353] NRECA reiterates a proposal made in its comments to the NOPR that, for mid-term sales, the Commission should enforce a matching or consistency principle: The same generating units should be used as the basis for the fixed and variable costs in determining the default embedded-cost rate.[354] NRECA asserts that a matching or consistency principle would help to ensure that a mitigated seller cannot mix high-fixed-cost units with high-variable-cost units to artificially inflate the embedded-cost rate. At the same time, NRECA adds that if a seller can show that a portfolio of generating units is likely to be used to provide service, then the seller might be permitted to use a weighted average of the fixed and variable costs of the portfolio.

262. NRECA also proposes that the Commission require public utilities, in addition to justifying their mitigated rates prior to the rate becoming effective, to also file *ex post* quarterly reports of the actual sales and the actual incremental or embedded costs incurred in making sales for terms of one year or less. Such mitigated cost-based rate sales, NRECA reasons, would be subject to a cost-based formula rate, and thus subject to refund. In NRECA's view, providing for a case-by-case review of proposed cost-based rates prior to implementation of the rates does not address concerns that arise after the mitigated cost-based rates become effective.[355]

263. NRECA contends that it is inconsistent with the FPA[356] to place the burden on customers to file a complaint pursuant to section 206[357] in order to ensure that the mitigated rates are just and reasonable in the first instance. Moreover, NRECA claims that because any rate relief would be prospective from the date of the complaint,[358] this would allow unjust and unreasonable rates to be charged until a complaint is filed.[359]

Commission Determination

264. On the issue of selecting the particular units that form the basis of the ''up to'' rate for mitigated mid-term sales, we will continue to apply our current methodology. TDU Systems and NRECA are concerned that the Final Rule failed to adopt measures to ensure that proposed mitigated rates for sales of less than one year reflect the mitigated sellers' actual cost of service. These entities assert that imposing a matching or consistency principle on mitigated sellers' proposed cost-based rate methodologies would help to prevent mitigated sellers from mixing high fixed-cost units with high variable-cost units that could artificially inflate the mitigated seller's embedded cost rate. We find that the Commission's current methodology allows mitigated sellers reasonable discretion to propose units to use in determining a cost-based rate while at the same time requiring any such proposal to be cost-justified and approved by the Commission. This balancing of a seller's right under the FPA to propose rates with the obligation to cost-justify such rates to the Commission provides the Commission adequate oversight to ensure that rates remain just and reasonable, and to prevent the mitigated seller from artificially inflating its cost-based rates. Once a seller files proposed rates, they are noticed for comment, and interested parties may file requests to intervene and comments. If there are issues of material fact as to the proposed rates, such issues may be set for hearing. The Commission reviews the mitigated seller's proposed rates, including a

[346] 75 FERC ¶ 61,168 (1996) (*UtiliCorp*).

[347] Ameren Rehearing Request at 8.

[348] Order No. 697 at P 592. To use an example cited by Ameren, once past sales information is filed with the Commission in an EQR, such information would not be covered by the information disclosure prohibition.

[349] *Id.* P 649.

[350] NRECA Rehearing Request at 25; TDU Systems Rehearing Request at 9.

[351] TDU Systems Rehearing Request at 4 (citing *K N Energy, Inc.* v. *FERC*, 968 F.2d 1295, 1303 (D.C. Cir. 1991)).

[352] NRECA Rehearing Request at 3 (citing *N. States Power Co.* v. *FERC*, 30 F.3d 177, 181–82 (D.C. Cir. 1994); 5 U.S.C. 706(2)(A), (C)).

[353] TDU Systems Rehearing Request at 4 (citing *American Mining Congress* v. *EPA*, 907 F.2d 1179, 1187 (D.C. Cir. 1990)).

[354] *Id.* at 27 (citing *N. States Power Co.* v. *FERC*, 30 F.3d 177, 181–82 (D.C. Cir. 1994)); *see also* TDU Systems Rehearing Request at 26–27.

[355] *Id.* at 25–26.

[356] *Id.* at 26 (citing *Mun. Light Bds.* v. *FPC*, 450 F.2d 1341, 1348 (D.C. Cir. 1971)).

[357] *Id.* (citing 16 U.S.C. 824e).

[358] *Id.*(citing 16 U.S.C. 824e(b)).

[359] *Id.* at 27 (citing *Arkla* v. *Hall*, 453 U.S. 571, 582 (1981)).

stacking analysis to determine the seller's generation unit(s) likely to provide the service.[360] In addition, the Commission analyzes the cost-justifications for the proposed rates to determine if the proposed rates meet the just and reasonable standard. As such, while a mitigated seller has the discretion to propose its choice of units, the Commission's process of reviewing the rate resulting from a seller's proposal ensures that such sellers do not have ''excessive leeway'' in proposing a cost-based rate, despite NRECA's claim to the contrary.

265. NRECA argues that placing the burden on customers to file a section 206 complaint to ensure mitigated rates are just and reasonable in the first instance is inconsistent with the FPA. Rather than placing a burden on customers to ensure just and reasonable rates, the Commission first requires the mitigated seller to cost-justify any proposed cost-based rates. To wit, the mitigated seller may propose cost-based rates for Commission review; however, the seller does not have authorization to charge such rates until the Commission acts on the seller's proposal. Thus, the Commission's process does ensure that a mitigated seller's rates are just and reasonable in the first instance. To the extent that a mitigated seller's cost of providing the service decreases, the Commission's long-standing practice is to consider claims of over-recovery in complaint proceedings.[361] Moreover, beyond proposing its matching principle, NRECA has failed to explain how adding this requirement would improve our current mitigation methodology. NRECA also provides no justification for treating mitigated sellers using a cost-based rate differently than any other cost-based rate sellers.

266. NRECA also complains that without a reporting procedure for mid-term sales requiring ex-post filings of quarterly reports of actual sales and costs incurred, the Commission cannot ensure that the default cost-based rates for mitigated mid-term sales reflect the actual cost of service and are just and reasonable.[362] However, as the Commission determined in Order No. 697, when a mitigated seller proposes cost-based mitigation, such an entity is obligated to comply with the Commission's accounting and reporting regulations, found in Parts 41, 101 and 141 [363] of the Commission's regulations.[364] As the Commission explained, these requirements are imposed in order to maintain adequate financial information with regard to mitigated sellers so that the Commission can exercise its duties and responsibilities under the FPA to ensure that rates remain just and reasonable and not unduly discriminatory or preferential.[365] The Commission and customers and competitors can rely on these financial forms to evaluate the adequacy of existing cost-based rates.[366] The Commission expects that customers' access to this data will allow them to demonstrate if rates have become unjust and unreasonable.[367]

b. Sales of One Year or Greater

Final Rule

267. The Final Rule retained the existing default mitigation policy for sales of one year or more (long-term). Specifically, the Commission determined that it will continue to require mitigated sellers to price long-term sales on an embedded cost of service basis and to file each such contract with the Commission for review and approval prior to the commencement of service.[368] We note that our mitigation in this regard is prospective and does not impact any existing long-term contracts.

268. Furthermore, the Final Rule retained the existing generation market power analyses (renamed to be a horizontal market power analysis) with minor changes and dismissed the request that the Commission consider different product analyses for short- and long-term products.[369] Instead, the Final Rule retained the existing mitigation where a failure to rebut the presumption of short-term market power results in the mitigation of both a seller's short-term and long-term sales.

Requests for Rehearing

269. Long-Term Sellers (LT Sellers),[370] Ameren, Southern, EEI, and OG&E take positions, in whole or in part, that the Commission erred in the Final Rule by adopting a policy that (1) generically mitigates long-term transactions based on a finding of market power under the Commission's horizontal market power analyses which focuses on short-term markets; (2) fails to recognize that absent entry barriers, long-term capacity markets are inherently competitive; and (3) does not account for previously recognized distinctions between short-term and long-term transactions.[371] Some assert that mitigation of long-term transactions is inconsistent with the Commission's finding in Order No. 697 that long-term markets are presumptively competitive, could reduce competition and raise prices in long-term markets, and have the effect of discouraging long-term transactions and investment, which the Commission has encouraged.[372] They seek clarification and/or rehearing of this policy.

270. They put forth the following arguments and rationale in support of

[360] A stacking analysis is performed in order to determine the fixed costs associated with the generating units likely to participate in off-system sales, where the related energy is priced based on incremental costs. The first portion of the analysis is the stacking of the generating units where data is recorded from each unit in the order of increasing Fuel O&M cost per kWh (lowest to highest). Power for off-system sales will only be provided after the utility has met its firm native load. The analysis assumes that the native load approximates the company's annual peak (in other words, any unit needed to serve the utility's minimum annual peak will not be available for off-system sales). The next part of the analysis is to determine which units will participate in the off-system sale. This part of the analysis can be a judgmental process. First, one eliminates those units that are uneconomical to make the sale. Next, one selects those units that are (1) usually stacked just above the peak and (2) have fuel costs that are economical to make the off-system sale.

[361] *Allegheny Power System Operating Cos.*, 111 FERC ¶ 61,308, at P 46 (2005) (''if a concern arises regarding over-recovery of transmission costs, such parties are free to seek relief by filing a complaint * * * pursuant to section 206 of the FPA.''); *Michigan Wolverine Power Supply Coop., Inc.*, 99 FERC ¶ 61,326 (2002).

[362] We note that while public utilities are required to file electric quarterly reports detailing transaction information, including price, for all market-based and cost-based power sales, such reports do not contain ex-post details of individual cost components.

[363] Part 41 pertains to adjustments of accounts and reports; Part 101 contains the Uniform System of Accounts for public utilities and licensees; Part 141 describes required forms and reports. Section 301(a) of the FPA authorizes the Commission to prescribe rules and regulations concerning accounts, records and memoranda as necessary or appropriate for the purposes of administering the FPA.

[364] Order No. 697 at P 986, 992.

[365] *Id.* P 993.

[366] *See*, e.g., *Quarterly Financial Reporting and Revisions to the Annual Reports*, Order No. 646, FERC Stats. & Regs. ¶ 31,158, at P 16–17, *order on reh'g*, Order No. 646–A, FERC Stats. & Regs. ¶ 31,163 (2004).

[367] *See Houlton Water Company*, 55 FERC ¶ 61,037 (1991) (dismissing complaint where customers failed to present prima facie case of excessive rates and noting that they had access to utility's Form No. 1 data, among other data, and could prepare cost study on that basis).

[368] *Id.* P 659 (citing April 14 Order, 107 FERC ¶ 61,018 at P 151, 155).

[369] *Id.* P 122.

[370] LT Sellers include Public Service Company of New Mexico, Duke Energy Corporation, E.ON U.S., Progress Energy, Inc. (filing on behalf of its subsidiaries), Oklahoma Gas and Electric Company, PacifiCorp, Tucson Electric Power Company, Arizona Public Service Company, and Pinnacle West Marketing & Trading Co., LLC.

[371] Southern Rehearing Request at 26 (citing *Wholesale Competition in Regions with Organized Electric Markets*, Advance Notice of Proposed Rulemaking, FERC Stats. & Regs. ¶ 32,617, at P 85 (2007), and Energy Policy Act of 2005, Pub. L. No. 109–58, 119 Stat. 594 (2005), sec. 1253).

[372] Ameren Rehearing Request at 9; LT Sellers Rehearing Request at 3, 10. *See also* EEI Rehearing Request at 11; OG&E Rehearing Request at 11.

their requests, and offer specific options for the Commission to consider in terms of relief. Southern states that, according to the Final Rule, the indicative screens are only ''snapshots in time,'' utilize only short-term data inputs focusing only on existing capacity holdings and consider only historical energy markets; thus, they cannot provide any reasonable information regarding supply and demand conditions in future markets. Southern and OG&E argue that the Commission should abandon the indicative screens and the DPT as bases for mitigation measures in long-term markets and that a more appropriate analysis for determining whether market power exists in long-term markets is whether potential suppliers are barred from entering the market.[373] LT Sellers, Southern, and EEI argue that the analysis of long-run market power should consider vertical market power.[374] EEI offers that, absent barriers to entry and vertical market power, buyers in long-term markets have competitive alternatives, including the option to build new generation or to enter long-term transactions for third parties to do so, that will preclude sellers from exercising market power. EEI requests that the Commission clarify that it will consider the ability of a seller to exercise vertical market power or to erect other barriers to entry, rather than horizontal market power, in determining whether sellers may enter long-term transactions at market-based rates.[375]

271. In terms of specific ways the Commission may address the issue of long-run market power, LT Sellers asked the Commission to find that the Final Rule allows sellers who fail one or both indicative screens to file a separate tariff for long-term capacity and energy sales at market-based rates, and that such a tariff would be accepted if that seller satisfies the Commission's vertical market power analysis, which addresses the relevant issues regarding long-term sales: Transmission market power and barriers to entry.[376] According to LT Sellers, such tariffs could be limited by their terms to contracts of sufficient duration and that begin sufficiently far into the future to ensure that self-building or new construction by others is a viable option and, thus, that the threat of new entry disciplines the prices under the contracts subject to the tariff.[377]

272. LT Sellers recognizes that there will be circumstances in which a tariff for long-term sales at market-based rates may not be appropriate for a particular seller. Therefore, LT Sellers contends that the Commission should establish several safe harbors for factual circumstances in which the Commission can take comfort in the lack of long-term market power such that a seller can file stand-alone long-term contracts with the Commission under a rebuttable presumption that the contract rate is just and reasonable.[378] For example, LT Sellers suggests that a safe harbor would be appropriate where a seller demonstrates that its buyer conducted an *Allegheny*-type request for proposals, or where it conducted an informal procurement and provides sufficient evidence that the contract was not the result of any market power.

273. Southern, Ameren, OG&E, and EEI similarly request that the Commission clarify that even if a seller's blanket market-based rate authority is revoked, the seller may still seek Commission approval of long term market-based rate contracts on an individual basis.[379] Southern argues that this clarification is necessary and appropriate because the absence of blanket authorization to make market-based rate sales should not preclude a seller from entering into long-term market-based rate transactions with individual buyers over whom the seller does not have market power. Southern also requests that the Commission clarify the standards that it would utilize in determining whether to approve individual long-term market-based rate contracts on a case-by-case basis. In this regard, Southern submits that for each such long-term transaction filed with the Commission for approval, there would be no presumption that the seller has market power over the applicable buyer. Instead, there would be a separate evaluation process that would consider the specific circumstances applicable to each particular transaction and buyer.[380] According to Southern, the Commission should consider establishing other exceptions to allow sellers without blanket market-based rate authority to transact on a long-term basis, and the Commission should undertake to identify the types of circumstances where market power concerns generally are not present, irrespective of whether a seller ultimately passes the Final Rule's criteria for blanket authority.[381]

274. Several petitioners take a contrary view. APPA/TAPS and Montana Counsel, in whole or in part, are concerned that the Commission's statement about the inherent competitiveness of long-term markets may invite public utilities to seek to avoid any examination of market power in long-term markets, even on a case-specific basis.[382]

275. While Montana Counsel agrees that ''[t]he markets for short-term energy purchases and long-term firm capacity supplies are undeniably distinct,'' it states that the Commission should not assume that there can be no market power for long-term firm capacity supplies; instead, it should require market-based rate applicants to demonstrate that they do not possess market power in the long-term market.[383] In particular, Montana Counsel argues that the Commission seems to assume that barriers to entry are the exception rather than the rule, and that generation will usually be built to counteract long-term market power. Montana Counsel argues that the Commission's reliance on an academic hypothesis for its statement that ''[a]s the Commission has stated in the past, absent entry barriers, long-term capacity markets are inherently competitive because new market entrants can build alternative generating supply'' in support of a major policy is unsupported, arbitrary, and capricious. Montana Counsel offers that at least one recent analysis of barriers to entry in generation markets weighs against the Commission's assumption.[384]

276. Montana Counsel states that the presence in a market of a seller with market power can itself be a barrier to entry, especially if the market is isolated by transmission constraints; for example, any new entrant would face the risk of predatory pricing by the incumbent seller, and transmission constraints would prevent the newly-built generation from being ''moved'' to a more hospitable market. Montana Counsel states that if the Commission grants market-based rate authority to a seller based on a presumption that new generation can enter the market and that

[373] Southern Rehearing Request at 27–28; OG&E Rehearing Request at 10.

[374] LT Sellers Rehearing Request at 10; Southern Rehearing Request at 28; and EEI Rehearing Request at 5, 10–11.

[375] EEI Rehearing Request at 10–11. *See also* Ameren Rehearing Request at 10.

[376] *Id.* at 21.

[377] *Id.* at 10–11.

[378] LT Sellers Rehearing Request at 11, 24–27.

[379] Southern Rehearing Request at 29–30; Ameren Rehearing Request at 10; OG&E Rehearing Request at 11.

[380] Southern Rehearing Request at 29.

[381] *Id.* at 30.

[382] APPA/TAPS Rehearing Request at 12–13.

[383] *Id.* at 7.

[384] Montana Counsel Rehearing Request at 4–5 (citing John M. Kelly, *Power Plants Don't Fly—and Other Non-Artificial Barriers to Competition in Wholesale Power Markets*, 26th USAEE/IAEE North American Conference Plenary Session, (Sept. 25, 2006)).

seller in fact has market power, it will be allowing unjust and unreasonable rates.[385]

277. APPA/TAPS also challenge the Commission's statement regarding the competitiveness of long-term markets, arguing that an examination of the evidence shows a lack of factual support for this conclusion.[386] In addition, they assert that the scope of RTO/ISO mitigation is much narrower than the default, cost-based mitigation the Commission prescribes; they note that the Commission has stated that RTO/ISO mitigation and the market-based rate analysis are different and that "'pieces of one should not automatically be used as precedent for the other.'"[387] APPA/TAPS state that RTO/ISO mitigation measures apply only to spot markets and day-ahead and/or real-time, but do not apply to weekly, monthly or long-term transactions, including those negotiated on a bilateral basis, and that RTO/ISO mitigation is often far less protective than the Commission's default cost-based rates.

278. Montana Counsel states that the Commission should consider evidence on the subject of barriers to entry in generation markets in this rulemaking, and in individual proceedings it should require sellers seeking market-based rate authority to present data on current generation markets from which the Commission can develop a factual record on which it can base a reasoned decision.[388] Montana Counsel argues that the burden of demonstrating the existence of barriers to entry should not be on intervenors; rather the burden should be on the seller seeking the privilege of market-based rate authority to demonstrate the absence of barriers to entry, *i.e.*, the existence of a competitive market for long-term power supply.

Commission Determination

279. As discussed below, we will grant rehearing in part and modify our policy regarding the mitigation of long-term sales. The Commission has long held that long-term markets may be presumed to be competitive, absent barriers to entry, and has taken actions within its authority to eliminate barriers to entry.[389] Even if a seller is found to have market power in the short-term, that market power can be mitigated or eliminated by the meaningful opportunity for other sellers to enter the market in order to compete with the seller and drive down prices.[390] Given adequate time, notice, and the absence of entry barriers, proposals for new infrastructure will emerge in response to price signals. Sellers and buyers will have an opportunity to plan and respond, as their needs dictate. Whether there is a meaningful opportunity for entry and when that opportunity is expected to occur may vary depending on such factors as the type or size of resource needed (e.g., system, peaking), whether multiple resources are needed (e.g., transmission and generation), and siting and permitting considerations.

280. In this regard, we agree with some of the concerns raised by petitioners and will allow sellers to demonstrate on a case-by-case basis that they do not have market power with respect to long-term contracts. We have considered the arguments raised by LT Sellers, Ameren, Southern, EEI and OG&E that the Commission erred in the Final Rule by adopting a policy that in all circumstances mitigates long-term sales based on a finding of market power under the Commission's horizontal market power analyses. We agree that the indicative screens and the DPT only examine the presence of market power in the short-term; the Final Rule did not alter the indicative screens or the DPT to allow different product analyses for short-term or long-term power. In response to Southern's assertion that the short-term analyses cannot provide any reasonable information regarding supply and demand conditions in future markets, we find that historical data, while perhaps an imperfect fit with regard to analyzing market power in forward markets and not to be relied on solely, does provide some indication as to the seller's ability to exercise market power. This notwithstanding, we believe that there is merit to petitioners' claims regarding the differences between long- and short-term markets, and the potential impact of the Final Rule on long-term contracting. As such, we grant clarifications and rehearing as discussed herein. Our decision to do so ensures just and reasonable rates while not impeding long-term contracting. To this end, and as discussed below, we are not, as Montana Counsel argues, simply relying on an unsupported hypothesis that entry will occur and discipline these markets to ensure just and reasonable rates. Rather, we will assess the facts and record presented with each individual section 205 application.

281. Accordingly, we grant rehearing in part and provide that any seller who fails the Commission's market-based rate test or surrenders market-based rate authority (referred to herein as "mitigated sellers") may file with the Commission under FPA section 205, on a case-by-case basis, a request for contract-specific market-based rates based on a demonstration that the seller does not have market power with respect to the specific long-term contract being filed. The Commission will not in this rulemaking promulgate tariffs of general applicability or provide generic safe harbors for long-term sales. As petitioners note, the market-based rate program focuses on short-term markets. The record before us is not sufficient to justify a generic market-based rate tariff for long-term sales or to create a "safe harbor" for such transactions.

282. Therefore, on a case-by-case basis, the mitigated seller must show that a buyer under a long-term contract has viable alternatives including the

[385] Montana Counsel Rehearing Request at 5 (citing FPA sections 205–206; *Gulf States Utils. Co.* v. *FPC*, 411 U.S. 747 (1973)).

[386] APPA/TAPS Rehearing Request at 6 (citing *AEP Power Marketing, Inc.*, 107 FERC ¶ 61,018 at P 155 (2004) (April 14 Order). APPA/TAPS also cites a study that concluded that investment was not occurring in high-priced LMP areas, which in theory should attract new entry. The study concluded "that the LMP price signals are overwhelmed by other factors in these areas, such as *structural barriers to entry*, competing economic incentives, and the lack of a clear mechanism for assuring return on investment in certain types of projects." Synapse Energy Economics, Inc., *LMP Electricity Markets: Market Operations, Market Power, and Value for Consumers*, Executive Summary (Feb. 5, 2007) available at *http://www.appanet.org/files/PDFs/SynapseLMPElectricityMarketExecSumm013107.pdf* (emphasis added by APPA/TAPS).

[387] APPA/TAPS Rehearing Request at 24 (citing *Midwest Independent Transmission System Operator, Inc.*, 109 FERC ¶ 61,157, at P 242 (2004), *order on reh'g*, 111 FERC ¶ 61,043 (2005).

[388] *Id.* at 5 (citing 5 U.S.C. 706(2); *Motor Vehicle Mfrs. Ass'n* v. *State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29 (1983)).

[389] *See Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036, *order on reh'g*, Order No. 888–A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888–B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888–C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group* v. *FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York* v. *FERC*, 535 U.S. 1 (2002); *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003) *order on reh'g*, Order No. 2003–A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003–B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003–C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs* v. *FERC*, 475 F.3d 1277 (D.C. Cir. 2007); *Regulation of Natural Gas Pipelines after Partial Wellhead Decontrol*, Order No. 436, FERC Stats. & Regs. ¶ 30,665 (1985); *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 FR 12,266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890–A, 73 FR 2984 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261 (2007).

[390] *See, e.g.*, W. Kip Viscusi, *et al.*, *Economics of Regulation and Antitrust* 153–55, (MIT Press 2000) (1992).

entry of an appropriate amount of third-party newly-constructed resources during the relevant future period as an alternative to purchasing under the contract at issue. In order to make the relevant showing, the seller would have to show that its proposed contract is of a sufficiently long duration and provides for service to commence sufficiently far into the future, such that other sellers had a reasonable opportunity to enter the market; and that a buyer had other viable, comparable alternatives, which could include self-build options and third-party new construction. This builds upon the LT Sellers' proposal (albeit in the context of a tariff) that such contracts ''could be limited by their terms to contracts of sufficient duration and that begin sufficiently far into the future to ensure that self-building or new construction by others is a viable option and, thus, that the threat of new entry disciplines the prices under the contracts subject to the tariff.'' [391] At this time we are not imposing any specific requirements on the evidence that the mitigated sellers must submit with their application. Nevertheless, we observe that mitigated sellers who identify a specific buyer for a proposed contract will be better able to provide the Commission with an understanding of the viable and comparable alternatives that the particular buyer may have.

283. The fact that the Commission will review all of these contracts under section 205 of the FPA and provide notice and opportunity for comment addresses Montana Counsel's concern that the Commission would rely on an academic hypothesis of entry without regard to the justness and reasonableness of rates. Sellers bear the burden in an FPA section 205 proceeding to demonstrate that rates are just and reasonable.[392] We have also addressed Montana Counsel's concern that we have placed the burden of proving barriers to entry on the intervenor. As stated above, the seller has the burden to show that its rates are just and reasonable and is required to make the requisite showing. The Commission will carefully examine the evidence that will be presented, and we will deny authority to charge a market-based rate for a long-term contract when the mitigated seller cannot meet its evidentiary burden. Intervenors are therefore in the position of rebutting this evidence; they do not carry the initial (or ultimate) burden of proof. Moreover, in any application for market-based rate authority, the seller has the burden to make the requisite disclosures regarding inputs to electric power production, describing its ownership of, control over, or affiliation with entities that own or control such facilities, as well as make an affirmative statement regarding whether it has erected barriers to entry in the relevant market and committing not to erect such barriers in the future. As noted in the Final Rule, ''we are not preventing intervenors from raising other barriers to entry concerns for consideration on a case-by-case basis.'' [393]

284. We do not share the concern espoused in Montana Counsel's example of predatory pricing by the incumbent seller. Predatory pricing occurs when a firm sets prices below the competitive level in order to drive competitors out of business, then, once competitors exit the market, uses its market power to drive the price above the competitive level. The economic theory of predatory pricing requires *both* the ability and incentive to do so. In Montana Counsel's example, if the mitigated firm did sell below the competitive price and drive out the competitors, it could not use its market power to raise the price at that time because it would be mitigated by the Commission to a cost-justified rate. In other words, such a strategy would be self-defeating because once competitors exit a particular market the remaining firm would no longer pass the indicative market power screens, and this would lead to its transactions being mitigated. Therefore, while a mitigated firm could, in theory, set prices below the competitive level to minimize or eliminate competitors, the Commission's mitigation policy creates an economic disincentive to do so, which erodes Montana Counsel's theory of economic harm.

285. With regard to APPA/TAPS' suggestion that the scope of RTO/ISO mitigation is much narrower than the Commission's default cost-based mitigation, we do not believe that such a distinction should require that cost-based mitigation be imposed on long-term contracts entered into by sellers with market power in RTO/ISO markets. In RTO/ISOs, buyers have access to centralized, bid-based short-term markets which will discipline a seller's attempt to exercise market power in long-term contracts because the would-be buyer can always purchase from the short-term market if a seller tries to charge an excessive price. The RTO/ISOs have Commission-approved market mitigation rules that govern behavior and pricing in those short-term markets. Further, the RTO/ISOs have Commission-approved market monitoring, where there is continual oversight to identify market manipulation.

c. Alternative Methods of Mitigation

Final Rule

286. The Commission determined that it will address on a case-by-case basis whether the use of an agreement that is not tied to the cost of any particular seller but rather to a group of sellers is an appropriate mitigation measure.[394]

287. Specifically, the Final Rule concluded that use of the Western Systems Power Pool Agreement (WSPP Agreement) as a mitigation measure may be unjust, unreasonable or unduly discriminatory or preferential for certain sellers. The Commission instituted in Docket No. EL07–69–000 a proceeding under section 206 of the FPA to investigate whether the WSPP Agreement ceiling rate is just and reasonable for a public utility seller in a market in which such seller has been found to have market power or is presumed to have market power.[395]

288. The Final Rule noted that the Commission had previously accepted the use of the WSPP Agreement ceiling rate as mitigation by a number of sellers. The Final Rule allowed the sellers to continue to use the WSPP Agreement ceiling rate as mitigation, subject to refund (as of the refund effective date established in Docket No. EL07–69–000) and subject to the outcome of the section 206 proceeding.[396]

289. The Commission issued an order in the section 206 proceeding on February 21, 2008, determining that the WSPP Agreement's demand charge ceiling rate is no longer just and reasonable for use by public utility sellers in the market in which the sellers do not have market-based rate authority, unless such sellers can cost-justify the rate.[397] The Commission found that in markets in which a seller has or is presumed to have market power it is unjust and unreasonable to allow such a seller to continue to use the WSPP-wide ''up-to'' demand charge as a ceiling rate unless the seller can justify the costs of that charge based on its own costs.

290. The Final Rule continued to permit alternative methods of mitigation to be cost-based. However, while the Commission did not allow the use of

[391] LT Sellers Rehearing Request at 11.

[392] 18 CFR 35.3(a).

[393] Order No. 697 at P 449.

[394] *Id.* P 667.

[395] *Id.*

[396] *Id.* P 673–74.

[397] *Western Systems Power Pool,* 122 FERC ¶ 61,139 (2008).

alternative ''market-based'' mitigation on a generic basis, the Commission held that it will permit sellers to submit alternative non-cost-based mitigation proposals for Commission consideration on a case-by-case basis.[398]

Requests for Rehearing

291. No entities sought rehearing regarding use of the WSPP Agreement to mitigate market power. APPA/TAPS request clarification that the Commission will entertain proposals for structural mitigation as a condition of the privilege of market-based rate authority in specific, future cases.[399] APPA/TAPS argue that the Commission, on the one hand, approves structural measures to mitigate horizontal market power, such as the transfer of existing generation to third parties but, on the other hand, declares that structural conditions, such as joint planning and construction of new generation, are too burdensome.[400] Where the Commission can impose conditions on an applicant's market-based rate authority, APPA/TAPS support structural mitigation as a potential condition, and urge the Commission to identify, in specific cases, structural conditions that would allow applicants to obtain market-based rate authority rather than be limited to cost-based mitigation.[401]

Commission Determination

292. As the April 14 Order and Final Rule both explained, ''[p]roposals for alternative mitigation * * * could include cost-based rates or other mitigation that the Commission may deem appropriate.'' [402] While APPA/TAPS complain that the Final Rule suggested some structural measures are too burdensome, in fact the Commission only determined that entities advocating structural mitigation as a condition on market-based rate authorization had not justified imposing such a burden on a generic basis. Rather than foreclosing the possibility of structural measures, the Commission will continue to permit sellers to submit non-cost-based mitigation proposals, including those involving structural measures, for Commission consideration on a case-by-case basis based on their particular circumstances.

293. APPA/TAPS also request that the Commission identify in specific cases structural conditions that will enable applicants to obtain market-based rate authority, as an alternative to ordering cost-based mitigation. The Commission believes that, because mitigation proposals are evaluated upon the particular facts and circumstances of individual proceedings, it would be premature to identify or list specific structural measures on a generic basis. Further, it has been the Commission's practice to allow sellers to propose mitigation to address market power concerns rather than the Commission imposing specific mitigation on mitigated sellers.

2. Protecting Markets With Mitigated Sellers

a. Must Offer

Final Rule

294. In the Final Rule, the Commission determined not to impose an across-the-board ''must offer'' requirement for mitigated sellers, explaining that there was insufficient record evidence to support instituting a generic ''must offer'' requirement, as had been proposed by several commenters. While commenters proposed several methods for implementing a must offer requirement,[403] the intent of these proposals was to preclude the mitigated seller from selling its available capacity in markets where it retains market-based rate authority without first requiring the mitigated seller to offer available capacity in the balancing authority area in which it is mitigated. The Commission found that although wholesale customer commenters raised theoretical concerns that they would be unable to access power absent a ''must offer'' requirement, they did not provide any concrete examples of harm nor did they explain how the potential harm justified the generic remedy they sought.[404] The Commission also found that there are potential remedies available on a case-by-case basis to a wholesale customer alleging undue discrimination or other unlawful behavior on the part of a mitigated seller.[405]

295. While the Commission did not impose a generic ''must offer'' requirement in the Final Rule, the Commission did not rule out the possibility of finding that the imposition of a ''must offer'' requirement, or some other condition on the seller's market-based rate authority, would be an appropriate remedy in a particular case, depending on the facts and circumstances, as the Commission has done in the past.[406]

296. For many of the same reasons that the Commission declined to impose a generic ''must offer'' requirement, the Commission also declined to adopt a ''right of first refusal'' as proposed by NRECA, whereby captive customers would have the right of first refusal to purchase at a market price energy or capacity that the mitigated seller proposes to sell outside of the balancing authority area in which it is mitigated. The Commission determined that there was insufficient record evidence to support imposition of such an across-the-board requirement.[407]

Requests for Rehearing

297. APPA/TAPS and NRECA request that the Commission clarify that the Final Rule does not pre-judge the circumstances in which a must offer condition may be necessary and appropriate to remedy undue discrimination or ensure that rates are just and reasonable.[408] APPA/TAPS state that the Commission appropriately ties a must offer condition to the need for a remedy to ensure that wholesale rates are just, reasonable and not unduly discriminatory, but objects that the Commission seems to be limiting any must offer condition or similar remedy only to cases involving OATT violations.[409]

298. NRECA states that one member of the Commission expressed uncertainty about whether a ''must offer'' requirement would be appropriate absent a showing that ''the mitigated seller is the only entity physically able to meet all of the buyer's needs.'' [410] NRECA requests that the Commission clarify that it has not pre-determined that it will set the bar for a must offer requirement to the standard of total monopoly because it is

[398] Order No. 697 at P 693.

[399] APPA/TAPS Rehearing Request at 22 (citing *California Indep. Sys. Operator Corp.* v. *FERC,* 372 F.3d 395 (D.C. Cir. 2004)).

[400] *Id.*

[401] APPA/TAPS Rehearing Request at 22–23 (citing *California Indep. Sys. Operator Corp.* v. *FERC,* 372 F.3d 395 (D.C. Cir. 2004)).

[402] April 14 Order, 107 FERC ¶ 61,018 at n.142; *see also,* Order No. 697 at n.46 and P 698.

[403] *See,* e.g., *id.* P 732.

[404] *Id.* P 759–60.

[405] *Id.* P 763.

[406] *Id.* P 764.

[407] *Id.* P 771.

[408] APPA/TAPS Rehearing Request at 4, 19 (citing *Transmission Access Policy Study Group* v. *FERC,* 225 F.3d 667 (D.C. Cir. 2000)); NRECA Rehearing Request at 29.

[409] APPA/TAPS Rehearing Request at 4. Additionally, APPA/TAPS disagrees with the characterization of its position as urging a ''generic remedy'' in the Final Rule. APPA/TAPS argues that it was careful to specify that the market power concerns posed by the particular market-based rate applicant would determine when a must offer condition would be appropriate. APPA/TAPS therefore states that it does not view the Final Rule as a rejection of its position. *Id.* at 18.

[410] NRECA Rehearing Request at 30 (citing Open Meeting Tr. at 61 (June 21, 2007)).

inconsistent with the standards adopted in the Final Rule.

299. NRECA argues that if a public utility seller is subject to mitigation in its home balancing authority area, the seller either has a dominant market share, its generation is critical for meeting peak-period demand, or both. In such cases, NRECA contends that the withholding of the seller's generation in its home balancing authority area could have a profound effect on the ability of a captive wholesale customer to provide electricity at a reasonable price.[411] NRECA further argues that if a total-monopoly standard were applied, a customer would not be entitled to relief so long as it could find another entity able to sell power to it. But, if that single alternative supplier had market power in the absence of competition from the ''mitigated'' seller, then the customer would be forced to buy that alternative supplier's power at monopoly prices, and the supposedly ''mitigated'' seller would be let off the hook. If that single alternative supplier were also subject to mitigation, then it too might choose to sell all of its power outside the balancing authority area, leaving the customer with no power at any price, contrary to FPA obligations.[412]

300. NRECA further argues that there is no clear guidance on who would have the burden of proof either to demonstrate that a must offer requirement or some alternative remedy is necessary or unnecessary, but that the Final Rule suggests that the customer would have the burden to prove such a remedy is necessary.[413] NRECA argues that the seller should bear the burden of proof in a particular case to demonstrate that this requirement or an alternative remedy is unnecessary.[414]

301. TDU Systems also argue that the Final Rule's determination not to impose an across-the-board ''must offer'' requirement for mitigated sellers leaves the Commission without any effective measures to assure that the granting of market-based rate authority in competitive markets will not make things worse in adjacent uncompetitive markets[415] and asserts that the Commission should reconsider the narrow range of mitigation measures it will employ in the first instance and include must offer conditions, annual open seasons, and rights of first refusal.[416] TDU Systems argue that the Commission's vague statement that it could consider such remedies in particular cases is not sufficient.[417] TDU Systems argue that if the Commission does not embrace a ''must offer'' requirement, regulations should list it as an option[418] because *National Fuel*[419] does not hold that the Commission must always determine that existing remedies and procedures are inadequate before it adopts any new regulation.[420]

302. Additionally, TDU Systems argue that if the Commission declines to impose a ''must offer'' requirement, it should, upon a finding of market power in a seller's home balancing authority area, deny market-based rate authorization in first-tier markets.[421] The immediate concern is the effects upon the public utility's continuing obligations to provide service at conventionally regulated rates in markets where it has market power.[422]

303. TDU Systems argue that it may be appropriate to impose upon sellers the initial burden of coming forward with the proposed remedy.[423] TDU Systems argue that the regulations should state that the Commission will look favorably upon a public utility's proposal to mitigate market power by entering into an enforceable commitment to provide additional transmission capacity.[424]

304. Finally, TDU Systems argue that the Commission has been aware that relying upon the rights of individual customers to file complaints after the fact is often not enough to assure overall achievement of FPA mandates.[425]

Commission Determination

305. In response to issues raised by APPA/TAPS and NRECA, we clarify that we have not pre-judged the types of specific situations in which we might impose a ''must offer'' requirement on a particular seller.

306. With respect to which party bears the burden of proof regarding a ''must offer'' requirement, we cannot make that determination in the abstract. The public utility seller has the burden under section 205 to demonstrate that its mitigation proposal is just, reasonable and not unduly discriminatory. Circumstances in which a must-offer requirement warrants consideration cannot be determined in advance, as we made clear in the Final Rule. If the public utility seller can meet its burden of showing that its mitigation proposal is just and reasonable without a must-offer requirement, however, then the burden would be on the challenging party to show that more is required.

307. TDU Systems continue to advocate the need for the Commission to impose an across-the-board ''must offer'' requirement on mitigated sellers; however, they do not provide evidence supporting such a requirement. For example, they have not provided evidence of a widespread and pervasive situation where customers were unable to access power due to a mitigated seller's business decision to sell its power outside of the balancing authority area in which the seller has been found, or presumed, to have market power. Absent such compelling evidence, we will not impose an across-the-board ''must offer'' requirement. As discussed in the following section, we also reject TDU Systems' request that the Commission, upon a finding of market power in a seller's balancing authority area, deny market-based rate authorization in first-tier markets.

308. We also reject TDU Systems' argument that the Commission list ''must offer'' in its regulations as a mitigation option. Section 35.38 of the Commission's regulations provides that a mitigated seller ''may adopt the default mitigation * * * or may propose mitigation tailored to its own particular circumstances to eliminate its ability to exercise market power.''[426] We find that defining in the regulations the mitigation options that are available to all sellers provides sufficient regulatory certainty and we decline to provide a list of possible remedies that may not be

[411] *Id.* at 31. NRECA also states that ''[t]he Commission allows wholesale contracts executed or filed after July 9, 1996, to terminate by their own terms without prior notice to and approval by the Commission. Thus, a captive wholesale customer with a 'new' long-term contract may have no regulatory assurance of continued service even in a control area where the seller has generation market power.'' NRECA at n.94 (citing 18 CFR 35.15(b)).

[412] *Id.* at 31 (citing 16 U.S.C. 824a(a) (authorizing Commission actions for 'assuring an abundant supply of electric energy throughout the United States with the greatest possibly economy'); 16 U.S.C. 824d(a) (requiring all rates to be just and reasonable); Energy Policy Act of 2005, section 1233, 119 Stat. 594, 957 (2005) (adding section 217 to FPA, to be codified at 16 U.S.C. 824q, to ensure long-term transmission rights to load-serving entities); *Am. Gas Ass'n* v. *FERC,* 912 F.2d 1496, 1516–18 (D.C. Cir. 1990) (remanding FERC's pre-granted abandonment rule for failing to address the ''protection of customers from pipeline exercise of monopoly power through refusal of service at the end of a contract period'')).

[413] *Id.* at 30.

[414] *Id.* at 4 (citing *Farmers Union Cent. Exch.* v. *FERC,* 734 F.2d at 1510; *NAACP* v. *FPC,* 520 F.2d 432, 438 (D.C. Cir. 1975); 5 U.S.C. 556(d); 5 U.S.C. 706(2)(A), (C); 16 U.S.C. 824d(e)); NRECA Rehearing Request at 30 (citing 5 U.S.C. 556(d); 16 U.S.C. 824d(e)).

[415] *Id.* at 4 (citing *Farmers Union Cent. Exch., Inc.* v. *FERC,* 734 F.2d 1486, 1510 (D.C. Cir. 1984)).

[416] *Id.* at 8–9.

[417] *Id.* at 9, 22.

[418] *Id.* at 25.

[419] *Id.* at 23 (citing *National Fuel Gas Supply Corp.* v. *FERC,* 468 F.3d 831 (D.C. Cir. 2006)).

[420] *Id.* at 23–24.

[421] *Id.* at 9, 26.

[422] *Id.* at 24.

[423] *Id.* at 25.

[424] *Id.* at 26.

[425] *Id.* at 25.

[426] 18 CFR 35.38(a).

applicable to all sellers. To do otherwise would introduce needless regulatory uncertainty.

309. TDU Systems argue that it may not be sufficient to rely on a customer's right to file a complaint. However, customers are not limited to filing a complaint. At the time that a seller proposes mitigation, a customer has the opportunity to make its case regarding concerns it may have with respect to its ability to access power if the seller is mitigated in the balancing authority area. The Commission fully considers comments made by intervenors and, on a case-specific basis, if the facts and circumstances demonstrate a ''must offer'' provision is needed to mitigate market power, the Commission may impose such a remedy.

b. First-Tier Markets

Final Rule

310. In the Final Rule, the Commission retained its policy to limit mitigation to the balancing authority area in which a seller is found, or presumed, to have market power. The Commission did not place limitations on a mitigated seller's ability to sell at market-based rates in balancing authority areas in which the seller has not been found to have market power.[427]

Requests for Rehearing

311. APPA/TAPS request the Commission to clarify that, while it sees no basis as part of the current proceeding to revoke an applicant's market-based rate authority beyond the balancing authority areas in which the applicant has been found to have (or has accepted the presumption of) market power, it is not ruling out broader remedies where required to mitigate the applicant's market power in a specific case.[428]

312. APPA/TAPS assert that they did not urge that widespread revocation of market-based rate authority beyond the home balancing authority area occur on a generic basis, but rather, that the Commission not narrowly circumscribe its own remedial authority in a specific case where mitigation of a particular seller's market power may require revocation of its market-based rate authority beyond its home balancing authority area.[429] APPA/TAPS argue that the Commission's statement that comments ''favoring revocation of a mitigated seller's market-based rate authority in markets where there has been no finding of market power, as well as those supporting broadening mitigation to first-tier markets, have not provided a sufficient legal basis for such a policy,'' [430] could be used against the Commission when it seeks to broaden the scope of mitigation in that future case where a more expansive remedy is factually and legally justified.[431]

Commission Determination

313. The Commission allows market-based rate sales of energy and capacity in all balancing authority areas where the seller has been granted market-based rate authority. As the Commission explained in the Final Rule, ''[w]e generally agree that it is desirable to allow market-based rate sales into markets where the seller has not been found to have market power.'' [432]

314. With regard to APPA/TAPS' concern that the Commission should not narrowly circumscribe its own remedial authority in a specific case where mitigation of a particular seller's market power may require revocation of its market-based rate authority beyond its home balancing authority area, we clarify that the Commission neither has nor will foreclose its authority to remedy market power.

c. Sales That Sink in Markets Without Mitigated Sellers

Final Rule

315. In the Final Rule, the Commission continued to apply mitigation to all sales in the balancing authority area in which a seller is found, or presumed, to have market power.[433] However, the Commission allowed mitigated sellers to make market-based rate sales at the metered boundary between a balancing authority area in which a seller is found, or presumed, to have market power and a balancing authority area in which the seller has market-based rate authority, under certain circumstances.[434]

316. The Final Rule determined that allowing market-based rate sales by a seller that has been found to have market power, or has so conceded, in the very balancing authority area in which market power is a concern, is inconsistent with the Commission's responsibility under the FPA to ensure that rates are just and reasonable and not unduly discriminatory.[435]

Requests for Rehearing

317. OG&E complains that the Commission erred by barring utilities from selling power within a balancing authority area in which a seller is found, or presumed, to have market power where the buyer's load sinks in a non-mitigated balancing authority area.[436] OG&E claims that the Final Rule mistakenly assumes that the point of sale is relevant to the market power analysis rather than the location of the load.[437] OG&E states that the Final Rule acknowledges that buyers taking title to power ''at a metered boundary for delivery to serve load in a balancing authority where the seller has market-based rate authority have competitive choices and therefore are not required to transact with the seller found to have market power within the mitigated balancing authority area(s).'' [438] OG&E suggests that this reasoning applies with equal force to a transaction where the buyer chooses to buy power at the seller's generator bus for load that is located in a balancing authority area where the seller has market-based rate authority because such a buyer also has competitive choices. OG&E argues that these choices are not reduced by the location at which title to the energy is transferred.[439]

318. OG&E also claims that the Commission's mitigation policy harms competition and consumers by undermining the ability of a mitigated company to compete in other markets within an RTO where that seller does not have market power.[440] OG&E asserts that if a power purchaser located in a non-mitigated market within an RTO already takes network transmission service under an OATT and that purchaser solicits power supply bids based on the premise that the purchaser will arrange and pay for any necessary transmission service, then potential suppliers not subject to mitigation will bid on a ''power only'' basis. In contrast, a mitigated supplier's bid would include the cost of transmission service to take the power to the metered boundary of the control area where the

[427] Order No. 697 at P 790.

[428] APPA/TAPS Rehearing Request at 4 (citing *Niagara Mohawk Power Corp.* v. *FPC,* 379 F.2d 153 (D.C. Cir. 1967)).

[429] *Id.* at 20.

[430] Order No. 697 at P 791.

[431] *Id.* at 4, 20–21.

[432] *Id.* P 819.

[433] Although the Commission used the term ''mitigated market'' in Order No. 697, the Commission later determined that ''balancing authority area in which a seller is found, or presumed, to have market power'' is a more accurate way to describe the area in which a seller is mitigated. *Clarification Order,* 121 FERC ¶ 61,260, at P 7 & n.10.

[434] Order No. 697 at P 817 (citing North American Electric Reliability Corporation. *Glossary of Terms Used in Reliability Standards* at 2 (2007), available at *ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May07.pdf*).

[435] Order No. 697 at P 819.

[436] OG&E Rehearing Request at 3.

[437] *Id.* at 4–5.

[438] Order No. 697 at P 820.

[439] OG&E Rehearing Request at 5.

[440] *Id.*

seller is mitigated. OG&E complains that in such an instance, the transmission service is not needed because the purchaser would prefer to use its existing network service—priced on the basis of load—to arrange for transmission. OG&E contends that the added transmission costs imposed on a mitigated supplier in such a scenario would undermine the competitiveness of a mitigated supplier's bid, thereby reducing the competitive options available to the purchaser. OG&E contends that the Commission's policy, because it can result in additional transmission costs for a mitigated supplier as described above, imposes a pancaked rate structure on mitigated suppliers, which undermines an essential benefit associated with RTO participation. This, OG&E complains, is inconsistent with the Commission's goal of eliminating pancaked rates by establishing RTOs, and will interfere with the development and efficiency of competitive wholesale markets.[441] OG&E adds that the Final Rule provides no justification for a policy under which a mitigated supplier may incur the cost of transmission service to take the power to the metered boundary of the control area when it seeks to sell power to a potential customer located in another non-mitigated balancing authority area within an RTO. These effects are even greater, OG&E asserts, because the Commission has approved other utilities' mitigation proposals that allow them to sell power at their generator bus so long as that power sinks in another balancing authority area. OG&E argues that those tariffs remain in full force and effect after Order No. 697. Like these sellers, OG&E should be permitted to compete on an equal basis to serve customers whose loads sink outside OG&E's mitigated balancing authority area.[442]

319. OG&E argues that the Final Rule fails to acknowledge that the Commission's new mitigation policy departs from prior policy.[443] OG&E asserts that in several recent cases where sellers failed the market share screens in their balancing authority area, the Commission imposed mitigation prohibiting the seller from making sales to "loads that sink" in that balancing authority area.[444] While the Commission later rejected this language, OG&E contends that it never has explained this change in position.[445] When the Commission departs from established policy without explanation, as OG&E claims it did here, it acts arbitrarily and fails to engage in the reasoned decision making required by the law.[446]

Commission Determination

320. OG&E complains that the Commission erred by barring utilities from selling power within a balancing authority area in which a seller is found, or presumed, to have market power when the buyer's load sinks in a non-mitigated balancing authority area. As noted in the Final Rule, another commenter similarly asserted that any buyer purchasing power at a generator bus or elsewhere in a balancing authority area in which a seller is found, or presumed, to have market power for purposes of moving that power beyond that mitigated balancing authority area should be treated no differently than a buyer who takes delivery of purchased power outside of that balancing authority area. OG&E, like earlier commenters advocating this approach, has failed to adequately address how the Commission could effectively monitor such sales to ensure that improper sales are not being made in the balancing authority area in which a seller is found, or presumed, to have market power. As the Commission stated in the Final Rule, several commenters noted the complex administrative problems that would be associated with trying to monitor compliance with such a policy.[447]

321. Moreover, as the Commission explained in the Final Rule, allowing market-based rate sales by a seller found to have market power, or has so conceded, in the very balancing authority area in which market power is a concern is inconsistent with the Commission's responsibility under the FPA to ensure that rates are just and reasonable and not unduly discriminatory. While we generally agree that it is desirable to allow market-based rate sales into balancing authority areas where the seller has not been found to have market power, a mitigated seller cannot make market-based rate sales anywhere within a balancing authority area in which a seller is found, or presumed, to have market power. It is unrealistic to believe that sales made anywhere in a balancing authority area can be traced to ensure that no improper sales are taking place. In contrast, sales made at the metered boundary for export do more readily lend themselves to being monitored for compliance, and the nature of these types of sales do not unduly disadvantage customers or competitors. Prohibiting market-based rate sales at the metered boundaries of a balancing authority area in which a seller is found, or presumed, to have market power could prevent or adversely impact cross border sales at these unique locations and reduce market liquidity unnecessarily in markets where the seller does not possess market power.

322. OG&E also claims that not allowing sales at the generator bus undermines the ability of a mitigated company to compete in other markets within an RTO where that seller does not have market power. For example, if a mitigated seller attempts to transact with a purchaser willing to use the purchaser's existing network transmission service, OG&E asserts that a mitigated seller's ability to compete is undermined. OG&E claims that because a mitigated seller must incur transmission costs to deliver the power in the above scenario to the metered boundary rather than simply to a generator bus in the balancing authority area in which a seller is found, or presumed, to have market power, the mitigated seller would be unable to bid on a "power only" basis and would be forced to pay an additional transmission cost that is redundant due to the purchaser's ability to use its network service if the mitigated seller could sell at the generator bus. This, OG&E suggests, not only undermines that mitigated seller's ability to compete beyond the mitigated balancing authority area, but also would reduce the competitive options available to the buyer.

323. OG&E's concern regarding mitigation undermining a seller's ability to compete fails to appreciate that mitigated sellers are prohibited from making sales at a generator bus in that particular balancing authority area because they have been shown to have, or conceded, market power in that market area. Mitigated sellers lose the privilege of market-based rate sales at generator bus locations within a balancing authority area in which a seller is found, or presumed, to have market power. Unlike sales at the generator bus bar, sales made at the metered boundary for export do lend themselves to being monitored for compliance, and these sales do not

[441] *Id.* at 6.

[442] *Id.* at 6–7.

[443] *Id.* at 7.

[444] *Id.* at 2 (citing *Duke Power,* 113 FERC ¶ 61,192 (2005); *AEP Power Marketing, Inc.,* 114 FERC ¶ 61,025 (2006); *LG&E Energy Marketing Inc.,* 113 FERC ¶ 61,229 (2005); *South Carolina Electric and Gas Co.,* 114 FERC ¶ 61,143 (2006); *Florida Power Corp.,* 113 FERC ¶ 61,131 (2005)).

[445] *Id.* (citing Order No. 697 at P 794; *MidAmerican Energy Co.,* 114 FERC ¶ 61,280 (2006); *Carolina Power & Light Co.,* 114 FERC ¶ 61,294 (2006); *Aquila, Inc.,* 114 FERC ¶ 61,281 (2006)).

[446] *Id.* at 8.

[447] Order No. 697 at P 818.

unduly disadvantage customers or competitors.

324. OG&E also claims that its ability to compete is undermined because the Commission approved several tariffs that permit a mitigated entity to sell power at their generator bus so long as that power sinks beyond the balancing authority area in which a seller is found, or presumed, to have market power. However, a recent Commission order explained that such tariffs are inconsistent with the Commission's policy as set forth in Order No. 697, as of the effective date of Order No. 697 (September 18, 2007).[448] In that order, the Commission explained that its acceptance of a mitigation proposal and tariff provisions that focused on sales that did not sink within the balancing authority area in which the seller was found, or presumed, to have market power was inconsistent with the April 14 and July 8 Orders and, therefore, in error.[449] Moreover, the Commission's recent order clarifying the Final Rule explained that sales made after September 18, 2007 must be in compliance with the requirements of Order No. 697.[450] Because a mitigated entity is precluded from limiting its mitigation to sales that sink in the balancing authority area in which it is found, or presumed to have, market power, all mitigated sellers are now on the same footing with regard to their ability to serve customers whose loads sink outside mitigated balancing authority areas.

d. Tariff Language

Final Rule

325. In the Final Rule, the Commission adopted a requirement that mitigated sellers wishing to make market-based rate sales at the metered boundary between a balancing authority area in which the seller was found, or presumed, to have market power and a balancing authority area in which the seller has market-based rate authority maintain sufficient documentation and use a specific tariff provision for such sales.[451] In particular, the Final Rule requires that mitigated sellers that want to make market-based rate sales at the metered boundary adopt the following tariff provision:

Sales of energy and capacity are permissible under this tariff in all balancing authority areas where the Seller has been granted market-based rate authority. Sales of energy and capacity under this tariff are also permissible at the metered boundary between the Seller's mitigated balancing authority area and a balancing authority area where the Seller has been granted market-based rate authority provided: (i) legal title of the power sold transfers at the metered boundary of the balancing authority area where the seller has market-based rate authority; (ii) any power sold hereunder is not intended to serve load in the seller's mitigated market; and (iii) no affiliate of the mitigated seller will sell the same power back into the mitigated seller's mitigated market. Seller must retain, for a period of five years from the date of the sale, all data and information related to the sale that demonstrates compliance with items (i), (ii), and (iii) above.

Requests for Rehearing

326. Pinnacle requests clarification of the provision's requirement that ''any power sold is not intended to serve load in the seller's mitigated market.'' As written, Pinnacle argues that this requirement could limit liquidity, particularly for term sales transactions, in the market trading hubs.[452] For example, Pinnacle states that it transacts at several liquid points in the Western markets such as Four Corners, which is at the border of the APS balancing authority area. Pinnacle explains that although it can assess its intent for the destination of power purchased at the border point, it does not have control over the intent of third parties purchasing the power. Further, Pinnacle asserts that it is unlikely that counterparties at liquid market hubs would agree to contractual limitations on where power can sink for term transactions.[453] Pinnacle adds that the Commission has not placed any limits on the time at which intent is determined. For example, if a buyer intends to sink the power outside of the market in which the seller has or is presumed to have market power at the time of purchase, but at the time of delivery determines that it must liquidate its positions and sell power back into that market, the Final Rule is unclear whether the mitigated seller may be liable for this sale into the market in which it has market power. Pinnacle argues that without the clarification on intent, mitigated sellers may be limited to cost-based sales at the border. Pinnacle requests the Commission clarify that intent is only directed at the determination of the mitigated seller.

327. If the Commission does not so clarify, Pinnacle requests on rehearing that the Commission revise the second requirement in the tariff provision to state: ''(ii) the seller does not intend for any power sold to serve load in the seller's mitigated market.'' Pinnacle claims that this revision will provide greater regulatory certainty.

328. Morgan Stanley similarly is unclear on how the Commission will ensure that a mitigated seller knows what an unaffiliated buyer intends to do with power. It adds that a restriction forbidding unaffiliated buyers from purchasing power at the metered boundary from a mitigated seller and then selling the same power back into a balancing authority area in which the seller was found, or presumed, to have market power would be burdensome because every sale would have to be tracked.[454] Morgan Stanley therefore requests the Commission to clarify that buyers unaffiliated with a mitigated seller may purchase power at the metered boundary to sell to customers that serve load in the mitigated seller's balancing authority area. It argues that if restrictions are imposed on unaffiliated buyers' purchases at the metered boundary, the Commission should explain or, in the alternative, grant rehearing.[455]

329. Pinnacle is further concerned about the metered boundary tariff provision's requirement that mitigated sellers commit to and demonstrate that ''no affiliate of the mitigated seller will sell the same power back into the mitigated seller's mitigated market.'' Pinnacle submits that it might generally have immediate documentation to meet the above requirement for real-time transactions because the NERC tag (that notes the sink point for the power) will be made upon the execution of a real-time transaction. However, in the context of a term sale, Pinnacle explains that NERC tags are generally created not at the time of the transaction, but rather the last scheduling day prior to the start of the sale. The result, Pinnacle submits, is that no immediate documentation is created to show that the mitigated seller intended to sink the sale outside of the mitigated market where a term sale followed by a ''coincidental sale''[456] that results in power returning to the

[448] *See South Carolina Electric and Gas Company,* 121 FERC ¶ 61,263 at P 12 (2007).

[449] *Id.*

[450] Clarification Order, 121 FERC ¶ 61,260 at P 4–8.

[451] Order No. 697 at P 830.

[452] Pinnacle Rehearing Request at 4. Although Pinnacle does not provide a definition for ''term sale,'' we understand their use of that phrase to refer to a sale that is neither executed nor tagged immediately, and whose sink location is unknown at the time of the sale.

[453] *Id.* at 5.

[454] Morgan Stanley Rehearing Request at 3.

[455] *Id.* at 2–3.

[456] Pinnacle describes a ''coincidental sale'' as the situation where, after a mitigated seller makes a term sale to an unaffiliated counter-party at the metered boundary, an affiliate of the mitigated seller enters into an unrelated transaction to buy that same power from the unaffiliated counterparty.

balancing authority area in which the seller has been found, or presumed, to have market power. Pinnacle therefore seeks clarification, or in the alternative rehearing, on whether the requirement that a mitigated seller commit to and demonstrate that ''no affiliate of the mitigated seller will sell the same power back into the mitigated seller's mitigated market'' applies in the following scenario: A mitigated seller sells a term product to an unaffiliated counterparty at the metered boundary for delivery sometime in the future. Thereafter, an affiliated seller purchases the power in a coincidental sale and, despite any lack of arrangement, the affiliate of the mitigated seller then re-sells that power to the balancing authority area in which the mitigated seller has been found, or presumed, to have market power.[457] If the unaffiliated counterparty does not advise the affiliate of the mitigated seller that the unaffiliated counterparty is selling to the affiliate of the mitigated seller the same power that the unaffiliated counterparty originally purchased from the mitigated seller, Pinnacle claims that it will only become apparent that the mitigated seller is sourcing the transaction between the unaffiliated counterparty and the affiliate of the mitigated seller when the NERC tags are prepared.[458]

330. Pinnacle also seeks clarification, or in the alternative rehearing, as to the types of documentation that the Commission requires to show the intent of the seller, and particularly whether the Commission would consider audio tapes of transactions to be sufficient. Pinnacle states that, generally, representative documentation for real-time trading is created. For a term sale, however, a representative tag is not created at the time of the transaction but rather around the last scheduling prior to the start of the sale. Therefore, when a term sale is involved, no immediate tag at the time of contracting is created that can be evidenced as intent to sink the sale outside of the market in which the seller has market power.

331. Pinnacle also requests clarification that the physical point of the metered boundary is the mitigated seller's side of the electrical boundary, and does not include points at the border that are in an adjacent balancing authority area.[459] If the Commission does not provide the requested clarification, Pinnacle requests rehearing of this requirement. Pinnacle argues that, as currently written, the tariff language on metered boundaries does not provide the regulatory certainty necessary to accurately implement the requirements.[460]

332. OG&E complains that the Final Rule's new mitigation policy is improperly based on the assumption that utilities will violate their tariffs despite the fact that such a purposeful circumvention of a company's mitigation tariff would subject the violator to the risk of substantial civil penalties. Moreover, OG&E adds that such conduct also could violate the Commission's Market Manipulation Rule.[461] OG&E points out that, in the Final Rule, the Commission rejected fears of gaming because such conduct would violate its existing rules.[462] OG&E asserts that the same logic applies to the Commission's concerns that a seller might violate its market-based rate tariff to purposefully make sales to a customer whose load sinks in the balancing authority area in which that seller was found, or presumed, to have market power. OG&E argues that, where a particular set of actions already are prohibited by the Commission's rules, the Commission cannot impose new requirements unless it first finds that the existing rules are ineffective.[463]

Commission Determination

333. As an initial matter, we will revise the tariff language governing market-based sales at the metered boundary to conform with the discussion in the Clarification Order regarding use of the term ''mitigated market.'' As we explained in the Clarification Order, we believe that ''balancing authority area in which a seller is found, or presumed, to have market power'' is a more accurate way to describe the area in which a seller is mitigated.

334. After considering comments raised regarding the difficulty of determining and documenting intent, we have decided to eliminate the intent element of the tariff provision, which states that ''any power sold hereunder is not intended to serve load in the seller's mitigated market.'' As we are eliminating the seller's intent requirement, we will modify the other tariff provision to require that ''the mitigated seller and its affiliates do not sell the same power back into the balancing authority area where the seller is mitigated.'' [464] Because we are eliminating the intent requirement, we need not address issues raised regarding documentation necessary to demonstrate the mitigated seller's intent.

335. Pinnacle also asks whether a mitigated seller would be liable if an affiliate purchases power from an unaffiliated intermediate party, then arranges to re-sell that power back into the mitigated seller's balancing authority area, and it is subsequently discovered, when the NERC tags are prepared, that the mitigated seller was the initial source of that power via a term sale with the unaffiliated intermediate party. Under these circumstances, the mitigated seller would have violated its market-based rate tariff. Whether or not prearranged by affiliates, a series of transactions involving what Pinnacle describes as a ''coincidental sale'' that may result in an affiliate re-selling power back into the balancing authority area in which the seller has been found, or presumed, to have market power are prohibited by Order No. 697. This is because mitigated sellers and their affiliates are prohibited from selling power at market-based rates in the balancing authority area in which a seller is found, or presumed, to have market power. Accordingly, an affiliate of a mitigated seller is prohibited from selling power that was purchased at a market-based rate at the metered boundary back into the balancing authority area in which the seller has been found, or presumed, to have market power.

336. To the extent that the mitigated seller or its affiliates believe that it is not practical to track such power, they can either choose to make no market-based rate sales at the metered boundary or limit such sales to sales to end users of the power, thereby eliminating the danger that they will violate their tariff by re-selling the power back into a balancing authority in which they are mitigated.

337. We also clarify that when using the term ''metered boundary,'' the Commission intends that applicable mitigation applies to sales made at the metered boundary regardless of at which ''side'' of the border the sale takes place. We adopt this approach as a concession to mitigated sellers that wish to make sales that may technically take place in a balancing authority area where they do not have market-based rate authority. However, in adopting this approach we do not intend to do so with such precision that we are drawn

[457] Pinnacle Rehearing Request at 7–8.

[458] *Id.*

[459] Pinnacle Rehearing Request at 8.

[460] *Id.* at 8–9.

[461] OG&E Rehearing Request at 9.

[462] *Id.* at 10.

[463] *Id.*

[464] To provide additional regulatory certainty for mitigated sellers, we clarify that once the power has been sold at the metered boundary at market-based rates, the mitigated seller and its affiliates may not sell that same power back into the mitigated balancing authority area, whether at cost-based or market-based rates.

into evidentiary hearings on this matter, which could result in long drawn out contractual disputes to determine the precise spot at which the sale took place. We further deny Pinnacle's request for rehearing to seek a precise definition of ''metered boundary'' because we believe, with the clarification provided herein, the existing tariff language on metered boundaries does provide the regulatory certainty necessary to accurately implement Order No. 697's requirements.

338. We disagree with OG&E's contention that our policy is based on the assumption that utilities will purposely violate their tariffs. We make no such assumption; however, it would not be sensible for us to establish conditions that we are unable to monitor for compliance. Sales at the metered boundary are unique physical locations that lie on the borders of balancing authority areas, and we believe that we can monitor compliance for sales at the metered boundary more effectively than sales made anywhere within the balancing authority area. As explained above, such limitation is justified by the Commission's need to monitor compliance with its conditions on sales within the balancing authority area in which the seller is mitigated.

339. Consistent with the preceding discussion, we will revise the tariff provision for market-based rate sales at the metered boundary as follows (bold font indicates new text):

Sales of energy and capacity are permissible under this tariff in all balancing authority areas where the Seller has been granted market-based rate authority. Sales of energy and capacity under this tariff are also permissible at the metered boundary between the Seller's mitigated balancing authority area and a balancing authority area where the Seller has been granted market-based rate authority provided: (i) legal title of the power sold transfers at the metered boundary of the balancing authority area where the seller has market-based rate authority; **and** (ii) **the Seller and its affiliates do not sell the same power back into the balancing authority area where the seller is mitigated.** Seller must retain, for a period of five years from the date of the sale, all data and information related to the sale that demonstrates compliance with items (i) **and** (ii) above.

340. Any sellers that have already adopted the tariff language prescribed in Order No. 697 are directed to revise the provision in accordance with this discussion on the next occasion when they otherwise would be required to file revised tariff sheets with the Commission, a change in status filing, or triennial review.

E. Implementation Process

Final Rule

341. In Order No. 697, the Commission created a category of market-based rate sellers (Category 1 sellers) that are exempt from the requirement to automatically submit updated market power analyses. These Category 1 sellers include ''wholesale power marketers and wholesale power producers that own or control 500 MW or less of generation in aggregate per region; that do not own, operate or control transmission facilities other than limited equipment necessary to connect individual generating facilities to the transmission grid (or have been granted waiver of the requirements of Order No. 888); that are not affiliated with anyone that owns, operates or controls transmission facilities in the same region as the seller's generation assets; that are not affiliated with a franchised public utility in the same region as the seller's generation assets; that are not affiliated with a franchised public utility in the same region as the seller's generation assets; and that do not raise other vertical market power issues.'' [465] Market power concerns for Category 1 sellers will be monitored through the change in status reporting requirement [466] and through ongoing monitoring by the Commission's Office of Enforcement. Category 2 sellers (all sellers that do not qualify for Category 1) will be required to file regularly scheduled updated market power analyses in addition to change in status reports.

342. In addition, to ensure greater consistency in the data used to evaluate Category 2 sellers, the Commission modified the timing for the submission of updated market power analyses.[467] Order No. 697 requires analyses to be filed for each seller's region on a pre-determined schedule, rotating by geographic region where two regions are reviewed each year, with the cycle repeating every three years.[468] This process allows evaluation of each individual seller's market power at the same time that other sellers in the same region are examined. For corporate families that own or control generation in multiple regions, the corporate family will be required to file an update for each region in which members of the corporate family sell power during the time period specified for that region.

1. Category 1 and 2 Sellers

a. Establishment of Category 1 and 2 Sellers

Requests for Rehearing

343. On rehearing, NASUCA argues that the exemption from market power review for Category 1 sellers lacks factual and legal justification. NASUCA contends that this exemption is inconsistent with the justifications the Commission has previously given to the courts. In particular, NASUCA argues that it is inconsistent with the Commission's arguments before the court that it carefully assesses the market power of any entity allowed to sell at market-based rates.[469]

344. NASUCA contends that in *Lockyer* v. *FERC,* 383 F.3d 1006 (9th Cir. 2004) (*Lockyer*), the Ninth Circuit mistakenly believed that the market power assessment under current Commission orders is made triannually (*i.e.*, once every four months) when it is only required triennially (once every three years).[470] NASUCA believes that, because the Final Rule would completely eliminate the triennial review for many sellers in Category 1, the basis for the decision in *Lockyer,* to the extent it is based on the Court's belief that the Commission reviews the market power of all sellers four times a year, is undermined. NASUCA concludes that the blanket exemption from market power review of all sellers owning or controlling less than 500 MW capacity is inconsistent with the Commission's stated rationale for allowing a market-based rate system.

345. NASUCA also argues that the Commission has reversed the burden previously placed on applicants for the ''privilege'' of having market-based rates.[471] NASUCA notes that the Final Rule states, '' '[w]hile it is true that a portion of these sellers will continue to sell at market-based rates for a time until their updated market power analyses (in the case of Category 2 sellers) or their filings addressing qualification as Category 1 sellers are due, *no commenter has submitted compelling evidence that Category 1 sellers have unmitigated market power.*' '' [472] NASUCA contends that Order No. 697 essentially granted all

[465] 18 CFR 35.36(a)(2) (citations omitted).

[466] *See* 18 CFR 35.42.

[467] Previously, updated market power analyses were submitted within three years of any order granting a seller market-based rate authority, and every three years thereafter.

[468] *See* Order No. 697 at Appendix D. The regions include the Northeast, Southeast, Central, Southwest Power Pool, Southwest, and Northwest.

[469] NASUCA Rehearing Request at 12–13.

[470] *Id.* at 13.

[471] *Id.* at 13–14 (citing *Schaffer* v. *Weast,* 546 U.S. 49 (2005); *Lavine* v. *Milne,* 424 U.S. 577, 585 (1976)).

[472] *Id.* (quoting Order No. 697 at P 334) (emphasis added by NASUCA).

Category 1 sellers market-based rates without their submitting an application demonstrating a lack of market power, and required objectors to submit ''compelling evidence'' in a non-evidentiary proceeding.

346. NASUCA argues that the Commission cannot presume that the market price demanded by all Category 1 sellers will be a ''competitive'' price or a just and reasonable rate.[473] NASUCA states that the Supreme Court ''rejected any conflation of 'competitive' market price with the 'just and reasonable' rate required by statute.'' [474] NASUCA contends that for Category 1 sellers, which it asserts are now exempt from any market power test, ''the 'prevailing price in the marketplace' is indeed the 'final' measure of the rates being demanded, changed and charged,'' a result contrary to the intent of Congress.[475]

347. NASUCA also argues that there is no basis in the record of this proceeding to assume that power marketers or producers who own or control less than 500 MW of generation lack market power at all times.[476] NASUCA notes that in load pockets or other transmission-constrained areas, sellers with less than 500 MW of capacity could exercise market power, either alone or acting strategically without overt collusion to inflate rates when supply margins are tight. NASUCA states that changing circumstances also may affect the opportunity of seemingly small sellers to exercise market power.

348. Additionally, NASUCA argues that, because the definition of seller includes not only owners of generating plants but also power marketers, this loophole might encourage power marketers to control segments of power plants up to 499.9 MW and through strategic bidding and other methods exercise subtle market power in certain locations at certain times.[477] NASUCA states that, as a result of this exemption, sales from these facilities will be at prices solely determined by market forces, in contravention of *FPC* v. *Texaco*. NASUCA therefore concludes that if the Commission desires to identify a threshold below which a seller cannot exercise market power, it should commence a new proceeding, conduct technical workshops, gather evidence from the public and from RTO market monitors, and receive comments before adopting an evidence-based standard.

[473] *Id.* at 14.

[474] *Id.* (citing *FPC* v. *Texaco,* 417 U.S. at 397).

[475] *Id.* at 15 (quoting *FPC* v. *Texaco,* 417 U.S. at 397).

[476] *Id.*

[477] *Id.* at 16.

Commission Determination

349. NASUCA's argument on rehearing that the Commission did not adequately justify its decision to exempt Category 1 sellers from filing regularly scheduled updated market power analyses is misplaced. As we reiterate below, we thoroughly discussed the basis of our decision in Order No. 697, including that exempting Category 1 sellers is fully consistent with our statutory mandate to ensure just and reasonable rates and with the court decisions that have construed that obligation.[478] Moreover, as discussed below, in a number of instances NASUCA does not accurately describe the exemption or our justification for it.

350. With regard to NASUCA's argument that exempting sellers from market power reviews undermines the court's decision in *Lockyer,* we note that the Commission addressed this concern in Order No. 697. Specifically, the Commission stated that ''the reporting requirement relied upon by the court in *Lockyer* is the transaction-specific data found in EQRs, which we continue to require of all sellers, and not the updated market power analyses. Thus, exempting Category 1 sellers from routinely filing updated market power analyses does not run counter to *Lockyer.*'' [479] The court in *Lockyer* emphasized that the Commission ''has broad discretion to establish effective reporting requirements'' for administering tariffs, and that the FPA ''explicitly leaves the timing and form'' of rate filings to the Commission's discretion.[480]

351. In any case, NASUCA fails to recognize that the Commission has not exempted Category 1 sellers from initial market power reviews. In addition, the Commission left in place the change in status reporting requirements that allow the Commission to review market power of sellers on an ongoing basis. Thus, we reject NASUCA's contention that this exemption is inconsistent with the justifications the Commission has previously given to the courts.

352. We also reject NASUCA's contention that the Commission has reversed the burden previously placed on applicants for the ''privilege'' of having market-based rates by not requiring Category 1 sellers to file regularly scheduled updated market power analyses. As an initial matter, NASUCA argues incorrectly that Order No. 697 ''essentially granted all Category 1 sellers market[-based] rates without their applying and demonstrating a lack of market power, and required objectors to submit 'compelling evidence' in a non-evidentiary proceeding.'' [481] Order No. 697 did not grant Category 1 sellers market-based rate authority without requiring the submission of an application demonstrating a lack of market power. To the contrary, all sellers seeking market-based rate authorization (including sellers that qualify as Category 1 sellers) must initially demonstrate either a lack of market power or that any market power is adequately mitigated in order to obtain Commission market-based rate authorization.[482] All such proceedings are noticed and allow for public comment. Any party to the proceeding has an opportunity during these proceedings to argue that a seller has market power.[483] Although Category 1 sellers are not required to file regularly scheduled updated market power analyses, they retain the initial burden of proof to demonstrate that they do not have or have adequately mitigated market power in the first instance. In addition, Category 1 sellers continue to have the burden of informing the Commission of any change in the circumstances that the Commission relied on in granting them market-based rate authority.

353. Further, NASUCA takes the Commission's statement regarding the submission of compelling evidence out of context. The passage that NASUCA quotes from the Final Rule (Order No. 697 at P 334) discusses the elimination of the exemption for new generation (formerly § 35.27(a) of the Commission's regulations), and the lack of compelling evidence that the Commission referenced there related to commenters' unpersuasive reasons for retaining the § 35.27(a) exemption.[484] The

[478] Order No. 697 at P 848.

[479] *Id.* P 854.

[480] *Lockyer,* 383 F.3d 1006, 1013.

[481] NASUCA Rehearing Request at 14.

[482] A seller who previously was not required to demonstrate a lack of horizontal market power based on the exemption contained in 18 CFR 35.27(a) and that believes it qualifies as a Category 1 seller, will be required to provide support for its claim to Category 1 status. This filing will give the Commission and interested parties an opportunity to review and, if appropriate, challenge a seller's claim that it qualifies as a Category 1 seller. To the extent that an intervenor has concerns about a seller's potential to exercise market power, the Commission will entertain them at that time. Order No. 697 at P 333.

[483] Additionally, if a seller's circumstances change from those which the Commission reviewed and made a determination upon, it is required to inform the Commission in a change in status filing.

[484] The Commission was responding to NASUCA's concern that sellers that initially

Continued

Commission discussed the establishment of Category 1 and 2 sellers in a separate part of the Final Rule (Order No. 697 at P 848–62); the Commission nowhere intimated that Category 1 sellers need not demonstrate that they lack market power. Accordingly, NASUCA's contention is rejected in this regard.

354. With respect to NASUCA's assertion that there is no basis in the record to assume that power marketers or producers who own or control less than 500 MW of generation lack market power at all times, in Order No. 697 the Commission fully explained the rationale underlying the adoption of Category 1, as well as the rationale for adopting 500 MW or less of generating capacity per region as the cutoff. The Commission explained that Category 1 sellers have been carefully defined to have attributes that are not likely to present market power concerns: Ownership or control of relatively small amounts of generation capacity; no affiliation with an entity with a franchised service territory in the same region as the seller's generation facility; little or no ownership or control of transmission facilities and no affiliation with an entity that owns or controls transmission in the same region as the seller's generation facility; and no indication of an ability to exercise vertical market power. The Commission further explained that, based on a review of past Commission orders, it is aware of no entity that would have qualified as a Category 1 seller but would nevertheless have failed the indicative screens, necessitating a more thorough analysis.[485] Furthermore, we believe that we have maintained an ample degree of monitoring and oversight to detect sellers that are not required to file regularly scheduled market power updates but nevertheless obtain enough additional generation as to raise market power concerns. This is so because we require all sellers seeking market-based rate authority to conduct a market power analysis and, once market-based rate authority is obtained, to submit change in status filings when the circumstances on which the Commission has granted market-based rate authority have changed. In these filings, such sellers must report on what effect, if any, the additional generation has on their market power. In addition, the Commission reserves the right to require an updated market power analysis from any market-based rate seller at any time.[486] Finally, all sellers with market-based rates, whether Category 1 or Category 2 sellers, must file electronically with the Commission an EQR of transactions no later than 30 days after the end of each reporting quarter.

355. Nevertheless, in light of concerns raised regarding the potential for Category 1 sellers to exercise market power in load pockets or other transmission-constrained areas, we will modify our approach when analyzing the indicative screens (e.g., as a result of regularly scheduled updated market power analyses). Specifically, to the extent that a Commission-identified submarket is under analysis, we will consider whether there is an indication that any sellers in that submarket, including Category 1 sellers, have market power. While we will not routinely require Category 1 sellers with generation assets in a submarket to submit a regularly scheduled updated market power analysis, when evaluating the market power analyses of Category 2 sellers, we will conduct our own analysis, based on publicly available information, of whether there are any market power concerns related to any Category 1 seller in a submarket. If, based on our analysis, we determine that there may be potential market power concerns with respect to any Category 1 sellers in a submarket, we will, if appropriate, require an updated market power analysis to be filed by such sellers. We will also notice such filings for public comment, thus allowing parties to raise concerns regarding market power for Commission consideration.

356. Regarding concerns about the specific threshold chosen, when the Commission proposed in the NOPR the establishment of Category 1 and Category 2 sellers, the Commission proposed to define Category 1 sellers as power marketers and power producers that own or control 500 MW or less of generation capacity in aggregate, among other requirements. The Commission received a variety of comments concerning the proposed threshold. After careful review of these comments, the Commission concluded that 500 MW or less of generation capacity per region is an appropriate threshold. The Commission explained in Order No. 697 that the 500 MW threshold would be used as a cutoff because, during the Commission's 15 years of experience administering the market-based rate program, there had only rarely been allegations that sellers with capacity of 500 MW or less (in any geographic region) had market power. The Commission noted that when those claims have been raised, the Commission's review either found no evidence of market power or found that the market power identified was adequately mitigated by Commission-enforced market power mitigation. The Commission explained that, while some commenters urged it to adopt either a higher or lower threshold, the Commission believes that a 500 MW threshold is both a reasonable balance as well as conservative enough to ensure that those unlikely to possess market power will be granted market-based rate authority. Moreover, 500 MW is a clear, bright line that will be easy to administer. On this basis, we reject NASUCA's suggestion that the Commission should commence a new proceeding, conduct technical workshops, gather evidence from the public and from RTO market monitors, and receive comments to further address the appropriate threshold.

b. Threshold for Category 1 Sellers

Requests for Rehearing

357. On rehearing, PPM contends that Order No. 697 does not provide any explanation as to why Category 1 membership is based on the ownership or control of generation in a ''region,'' as opposed to in the geographic area used to measure market power.[487] PPM submits that the appropriate geographic area for measuring ownership or control of electric generation for purposes of identifying Category 1 sellers is the same area used to assess market power: The balancing authority area or, for RTOs and ISOs, the relevant RTO/ISO market or submarket. PPM submits that the use of regions for determining Category 1 membership would result in a seller owning or controlling 500 MW of generating capacity located entirely in one balancing authority area being considered to have less chance of possessing market power than a seller owning or controlling 300 MW of generating capacity each in two separate balancing authority areas separated by hundreds of miles but located in the same region pursuant to the map provided in Appendix D to the Final Rule. PPM contends that there is neither evidence nor a rational basis for concluding that the seller in the second

received market-based rate authority without any generation market power assessment pursuant to 18 CFR 35.27(a) would, as Category 1 sellers, be exempted from filing update market power analyses. The Commission explained that it would rely on additional procedures, namely the change in status filing requirements (triggered by the acquisition of additional generation), EQR transaction filings, and the Commission's ability to require an updated market power analysis from any seller at any time, to address NASUCA's concern.

[485] *See* Order No. 697 at P 864.

[486] *Id.* P 853.

[487] PPM Rehearing Request at 2–3.

example should be included in Category 2 and the seller in the first example should be included in Category 1. Thus, PPM concludes that the Commission's basis for distinguishing between Category 1 and Category 2 sellers is arbitrary and capricious.

358. PPM also asserts that the Commission should treat ownership or control of intermittent generating capacity differently from thermal generating capacity for the purposes of establishing whether a seller falls within Category 1 or Category 2. PPM claims that it is extremely unlikely that any public utility will attain market power as a result of its ownership or control of wind generation capacity due to the intermittent nature of such capacity.[488] Thus, it argues that the Commission should adopt a less stringent limitation for purposes of establishing Category 1 status for sellers of power from intermittent generating capacity. PPM notes that the Commission rejected this suggestion from commenters, stating ''[w]e believe that many sellers with wind and other non-thermal capacity will fall below the 500 MW threshold; those that do not may take advantage of simplifying assumptions and other means to minimize the burden of filing an updated market power analysis.''[489] However, PPM asserts that, other than gas, wind power is the fastest growing source of electric generating capacity.[490] According to PPM, several wind power developers already own or control more than 500 MW of intermittent generation capacity in a region, as designated by Appendix D, and several more are likely to attain this status before long. PPM contends that, as the United States seeks to promote investment in electric generation technologies that enhance national energy security and do not emit greenhouse gases, it would be unwise to impose a burden on wind power generators that will not enhance the competitiveness of wholesale electric markets.

Commission Determination

359. With regard to PPM's argument that the use of regions for determining Category 1 membership would result in a seller owning or controlling 500 MW of generating capacity located entirely in one balancing authority area being considered to have less chance of possessing market power than a seller owning or controlling 300 MW of generating capacity each in two separate balancing authority areas separated by hundreds of miles but located in the same region pursuant to the map provided in Appendix D to the Final Rule, we find that PPM misses the point. The Commission's creation of a category of sellers (Category 1 sellers) that are not required to submit regularly scheduled updated market power analyses is based in part on recognizing the administrative burden imposed on smaller sellers that are unlikely to possess market power. In doing so, the Commission intends to remain conservative in its approach to identifying such sellers. While PPM's argument may make sense from a strictly analytical viewpoint, it also greatly increases the universe of sellers that would not be required to submit regularly scheduled updated market power analyses. We are not willing to do so.

360. The Commission explained in Order No. 697 that, ''[i]n keeping with our conservative approach with regard to which entities qualify for Category 1, we find that aggregate capacity in a given region best meets our goal of ensuring that we do not create regulatory barriers to small sellers seeking to compete in the market while maintaining an ample degree of monitoring and oversight that such sellers do not obtain market power.''[491] The Commission considered other formulations for a threshold, but it concluded that the other ''methodologies are inconsistent with a straightforward, conservative means of screening sellers * * *.''[492] Thus, we deny PPM's request to define Category 1 sellers based on their ownership or control of generation capacity located in a balancing authority area or an RTO/ISO market rather than based on ownership in a region.

361. With regard to PPM's request that the Commission adopt a less stringent limitation for purposes of establishing Category 1 status for sellers of power from intermittent generating capacity, as PPM acknowledges, the Commission considered and rejected this suggestion in the Final Rule. The Commission stated that it believed ''that many sellers with wind and other non-thermal capacity will fall below that 500 MW threshold''[493] and reiterated that those sellers that exceed it may take advantage of simplifying assumptions to minimize the burden of filing an updated market power analysis. While there may theoretically be some merit to PPM's assertion that it is unlikely that any public utility will attain market power as a result of its ownership or control of wind generation capacity due to the intermittent nature of such capacity, nevertheless, PPM's remark that wind power is the fastest growing source of generating capacity (other than gas) is further reason that intermittent capacity should not be treated differently from thermal generating capacity for purposes of establishing Category 1 status. There may be a time when a very large wind power facility could possibly have market power and will warrant Commission scrutiny. We note that PPM argues that the Commission should adopt a less stringent limitation for purposes of establishing Category 1 status for sellers of power from intermittent generating capacity because, in its view, it would be unwise to impose a burden on wind power generators that will not enhance the competitiveness of wholesale electric markets. However, PPM does not claim such a burden would be unduly burdensome. Nor should it. Our approach is balanced, reasonable, and consistent with our approach to examining market power of sellers seeking to obtain or retain market-based rate authority. On this basis, we believe it is appropriate that wind generators be subject to the same 500 MW threshold for Category 1 status as other sellers. At the same time, we note that we already afford intermittent generation more flexibility in conducting market power analyses than, for example, thermal generating capacity. In particular, we allow energy-limited resources to provide a market power analysis based on historical capacity factors to more accurately capture hydroelectric or wind availability, in lieu of using nameplate or seasonal capacity.[494] This is an option not available to thermal generating units. In addition, as we stated in the Final Rule, such sellers can take advantage of simplifying assumptions (such as performing the indicative screens assuming no import capacity or treating the host balancing authority area utility as the only other competitor). As a result, to the extent that a wind power generator exceeds the 500 MW threshold and therefore is considered a Category 2 seller, we believe that any burden imposed on that

[488] *Id.* at 4.

[489] *Id.* (citing Order No. 697 at P 867).

[490] *Id.* (citing Florence, Joseph, Global Wind Power Expands in 2006, ''Wind is the world's fastest-growing energy source with an average annual growth rate of 29 percent over the last ten years. In contrast, over the same time period, coal use has grown by 2.5 percent per year, nuclear power by 1.8 percent, natural gas by 2.5 percent, and oil by 1.7 percent.'' June 28, 2006 *http://www.earth-policy.org/Indicators/Wind/2006.htm*).

[491] Order No. 697 at P 865.

[492] *Id.* P 868.

[493] *Id.* P 867.

[494] *Id.* P 344. We also remind sellers that they may seek exemption from Category 2 status on a case-by-case basis. *See id.* P 868.

seller to file an updated market power analysis would be minimal.

2. Regional Review and Schedule

Requests for Rehearing

362. On rehearing, FirstEnergy and MidAmerican object to the regional filing approach adopted in the Final Rule.

363. FirstEnergy argues that the Commission erroneously and unreasonably ruled that for corporate families that own or control generation in different regions, the corporate family would be required to file an update for each region in which members of the corporate family sell power during the time period specified for that region.[495] FirstEnergy contends that a corporate family with generation assets in adjacent geographic markets finds it far more efficient to prepare and submit a single, all-encompassing, updated market power analysis every three years than to prepare separate analyses for each region.[496] It claims that adoption of a single filing date for all entities within a corporate family that have market-based rates will permit all necessary tariff revisions to be filed at the same time, and will thereby reduce the possibility for discrepancies among tariffs within the same corporate family.

364. FirstEnergy reasons that it is unlikely that there are a significant number of corporate families that have affiliated generation suppliers operating in adjacent geographic markets. For that reason, FirstEnergy states that there is no reason to believe that authorizing affected sellers to make a single, all-encompassing, triennial market power update filing every three years will significantly undermine the Commission's ability to obtain a complete view of market forces in each region in order to ensure that seller's rates remain just and reasonable.[497] In the event that the Commission permits all companies within a corporate family that operate in adjacent geographic markets to file a single market power updated analysis during a three-year filing cycle, FirstEnergy requests that the filing companies be given the option of selecting the region with which they will participate.[498]

365. MidAmerican seeks a filing schedule that permits it to submit a single market power analysis reflecting the generating facilities within its own balancing authority area (part of the Central region) as well as its Quad Cities Station (QCS), which is located on the border of that balancing authority area (part of the Northeast region). MidAmerican seeks to align the filing schedules to lessen the burden on the Commission in evaluating MidAmerican's market power, and the burden on MidAmerican in preparing multiple filings.[499] Its affiliate Cordova operates a generating facility also electrically located within the Northeast region, and MidAmerican states that Order No. 697 could be construed to require Cordova to file with the Northeast region.

366. MidAmerican states that, as affiliates, it and Cordova historically have prepared market power analyses that have evaluated the competitive effects of the aggregate generation owned and controlled by both. For that reason, Cordova is seeking to file on the same schedule as MidAmerican. QCS and Cordova's facility electrically are located immediately adjacent to MidAmerican's balancing authority area, and the metering points within the respective substations form part of the border between the Northeast and Central regions; each facility is geographically within the MidAmerican service territory and directly interconnected with the MidAmerican transmission system through facilities owned by MidAmerican.[500]

367. MidAmerican seeks clarification that its undivided ownership interest in QCS will not cause it to be deemed a seller that ''operates'' in the Northeast region subject to that region's filing schedule.[501] If the Commission is not willing to construe Order No. 697 in this manner, then, for the same reasons, MidAmerican seeks waiver of the filing schedule to permit QCS to be treated as part of MidAmerican's on-system generating resources; *i.e.*, as if QCS were within the Central region along with the other MidAmerican generating resources.[502] Cordova also seeks a similar clarification or waiver of Order No. 697 to permit its updated market power analysis to be made pursuant to the Central region schedule applicable to MidAmerican. MidAmerican states that its request is narrowly tailored to the circumstances applicable to itself and Cordova, whose relevant generation is located electrically either within or at the border of MidAmerican's balancing authority area in the Central region. By way of distinction, MidAmerican *is not* requesting permission to make a single filing for its entire corporate family.[503]

Commission Determination

368. The Commission specifically addressed FirstEnergy's argument in Order No. 697. The Commission stated that its decision to adopt a regional review properly and fairly balances the need to effectively monitor and mitigate market power in the wholesale markets with the desire to minimize any administrative burden associated with the filings and review of updated market power analyses. The Commission recognized that some sellers may have to file updated market power analyses more frequently than they would have had to before Order No. 697, but the Final Rule carefully balanced the interests of all involved. The Commission explained that the regional approach will enhance the Commission's ability to continue to ensure that sellers either lack market power or have adequately mitigated such market power.[504] We recognize FirstEnergy's contention that it is more efficient to prepare and submit a single, all-encompassing, updated market power analysis every three years than to prepare separate analyses for each region. However, such an approach does not satisfy our desire to ensure greater consistency in the data used to evaluate sellers' market power. If corporate families are allowed to combine all of their facilities nationwide into a single updated market power analysis, the study year and associated data may not be consistent with that required for the corresponding region, and thus the Commission's ability to ensure greater consistency in the data used to evaluate sellers' market power and to reconcile conflicting submissions would be undermined. Thus, we deny FirstEnergy's request for rehearing in this regard.

369. With regard to FirstEnergy's claim that adoption of a single filing date for all entities within a corporate family that have market-based rates will permit all necessary tariff revisions to be filed at the same time, and will thereby reduce the possibility for discrepancies among tariffs within the same corporate family, from an administrative perspective, we agree and note that nothing in Order No. 697 prohibits FirstEnergy or any other seller from making such a filing revising all of its market-based rate tariffs at the same time. Our concern addressed above pertaining to data consistency is not present with regard to making a

[495] FirstEnergy Rehearing Request at 3.

[496] *Id.* at 5.

[497] *Id.* at 6–7.

[498] *Id.* at 7. Alternatively, FirstEnergy suggests that the Commission should establish a process by which it would determine which cycle should be followed.

[499] MidAmerican Rehearing Request at 2.

[500] *Id.* at 4.

[501] *Id.* at 10.

[502] *Id.* at 10–11.

[503] *Id.* at 3–4.

[504] Order No. 697 at P 883.

corporation's market-based rate tariffs Order No. 697 compliant. Our analysis of market-based rate tariffs' compliance with Order No. 697 is not dependent on analyzing data but rather analyzing whether the tariffs meet the standards set forth in Order No. 697. Unlike analysis of data that can vary depending on the source of the data and the underlying assumptions, Order No. 697 set forth the standard by which the market-based rate tariff will be judged and those standards do not vary nor are they subject to assumptions.

370. We will deny MidAmerican's request for clarification. To the extent that a seller's generation facilities are electrically located in different regions, the intent of the regional review approach is for those facilities to be studied with their separate regions. We note that, prior to the adoption of the Final Rule, sellers were required to prepare a market power analysis for all of their generation assets nationwide. Some sellers with assets in multiple regions chose to submit their individual updated market power analyses when each was due rather than combining them into a single updated market power analysis. Others filed one updated market power analysis for the entire corporate family, with individual analyses of the different markets in which their assets are located. Either way, the same analyses were required to be filed before and after the Final Rule. Although the timing of the filings may differ post-Final Rule, the increased burden, if any, of filing pursuant to the regional approach is minimal.

371. With respect to MidAmerican's company-specific request for waiver from the requirements of Order No. 697, we will decline to act in the context of this generic rulemaking proceeding. We do not believe that this rehearing order is the proper vehicle to consider a waiver request which, as MidAmerican describes it, is narrowly tailored to itself and Cordova. MidAmerican's request for waiver may be submitted in another individual proceeding, and the Commission will consider the merits of its request at that time.

3. Clarifications on Implementation Process

372. During the period since Order No. 697 became effective, a number of implementation questions have come to the Commission's attention, either as a result of questions received from sellers or as raised in various filings. As we describe above, several of these issues were addressed in the Clarification Order issued on December 14, 2007. We will use this opportunity to provide additional guidance.

373. In the Clarification Order, among other things, the Commission explained that there may have been confusion concerning which data and market share calculations must be submitted as part of sellers' updated horizontal market power analyses.[505] The Commission clarified that market shares calculated for the wholesale market share screen and the DPT analysis should be based on the four seasons, as defined in the April 14 Order,[506] rather than the four quarters of the calendar year. The Clarification Order revised Appendix D to Order No. 697 to incorporate this clarification and explained that the study period runs from December of one year through November of the following year.

374. In the Clarification Order, the Commission also clarified which entities are required to file their updated market power analyses first. In Order No. 697, the Commission discussed the need for entities that have the information necessary to perform simultaneous transmission import limit studies to file in advance of those who will rely on that information.[507] In Appendix D of Order No. 697, the Commission identified those required to file first as ''Transmission Operators.'' However, the Commission explained in the Clarification Order, consistent with the discussion in paragraph 889 of Order No. 697, that *transmission-owning* utilities with market-based rate authority and their affiliates with market-based rate authority are the entities required to file their updated market power analyses first in each region.[508] Accordingly, revised Appendix D makes clear that transmission owners and their affiliates have earlier filing periods than other entities required to file in each region.

375. In the Final Rule, the Commission stated that it will entertain individual requests for exemption from Category 2, and that such requests must be filed no later than 120 days before a seller's next updated market power analysis is due. However, the period for filing updated market power analyses is not a specific date, but a month-long period (either December or June of each year). In response to questions regarding how to calculate 120 days prior to the filing period, we clarify that a seller must make a filing requesting an exemption from Category 2 no later than 120 days prior to the *first day* of the month in which its next updated market power analysis is due.[509]

376. In Order No. 697, the Commission explained that a power marketer that does not own or control generation assets in any region must submit a filing explaining why it meets the criteria for Category 1 and directed that such filings be submitted with the first scheduled geographic region in which the power marketer makes any sales.[510] Because the Commission has received several inquiries regarding this directive, we will provide further clarification here. If an unaffiliated power marketer has made no sales at any point in time since it obtained its market-based rate authority, it should make this submission during the next filing period, *i.e.*, June 1–30, 2008. We also clarify that, once a seller is determined to be in Category 1, it is not required to file updated market power analyses, or evidence of Category 1 status, for the other regions in which it makes sales so long as it continues to meet the criteria for a Category 1 seller.[511]

377. Additionally, in response to inquiries from certain sellers in the Central region, we will clarify the geographic area included in that region. Specifically, the Central region will now be defined to include portions of NERC Region RFC as follows: Central (Midwest ISO, NERC Regions MRO and RFC (not including PJM)).[512] Appendix D has been revised to reflect this description of the Central region.

378. Additionally, in Order No. 697 the Commission adopted a requirement that all sellers include an appendix listing generation assets as well as electric transmission and natural gas intrastate pipelines and/or gas storage facilities with certain filings, consistent with the example in Appendix B of Order No. 697.[513] We clarify that the transmission facilities that we require to be included in that asset appendix are limited to those the ownership or control of which would require an entity to have an OATT on file with the Commission (even if the Commission has waived the OATT requirement for a particular seller).

[505] We note that, in an effort to continue to improve upon the accuracy and consistency of data used within a region and to provide the Commission and the public with a more complete picture of the market, the Commission will allow RTO/ISOs to conduct market power studies that the RTO/ISO members can rely on in their market power filings.

[506] April 14 Order, 107 FERC ¶ 61,018 at n.85.

[507] Order No. 697 at P 889.

[508] Clarification Order, 121 FERC ¶ 61,260 at P 9.

[509] *See id.* P 868.

[510] *Id.* at n.1027.

[511] *See id.* P 849 (stating that subsequent to being found to be in Category 1, ''all Category 1 sellers will not be required to file regularly scheduled updated market power analyses.'')

[512] *Id.* at Appendix D.

[513] Order No. 697 at P 895.

379. Further, we clarify the manner in which transmission assets should be identified and described in the asset appendix. In order to lessen the reporting burden for sellers with large numbers of transmission facilities, we will allow a company to combine lines of a common size into one ''line item'' for purposes of the appendix; *i.e.*, 12 individual 500 kV lines could be identified as one line item in the appendix. For companies using this approach, rather than listing each line separately, the appendix must be filled out in a slightly different manner. Specifically, under the Asset Name and Use section of the appendix, rather than using the actual line name, a seller would insert an appropriate asset identifier. For example, if combining all 500 kV lines together the asset identifier would be ''Combined 500kV Lines.'' As a result, the Size section of the appendix would also change. Rather than identifying the actual size of each line, the seller would include the transmission asset size, described as the total combined length of all the lines of that size. Because the combined lines could run through several balancing authority areas and regions, the seller should split up its combined assets into separate balancing authority areas. Accordingly, the transmission asset aspect of the appendix would be filled out similar to the following:

Filing entity and its energy affiliates	Asset name and use	Owned by	Controlled by	Date control transferred	Location		Size
					Balancing authority area	Geographic region (per Appendix D)	
ABC Corp	Combined 500kV Lines.	ABC Corp	ABC Corp	NA	New York ISO and Tucson BA.	Northeast and Southwest.	Approx. 305 combined miles.
ABC Corp	Combined 500kV Lines.	ABC Corp	XYZ Inc	Jan. 1, 2000	Tucson BA	Southwest	185 combined miles.

380. However, we note that this combined approach can only be used if lines of the same size are controlled by the same entity. If there are lines of the same size controlled by different entities, they must be identified in different line items; *i.e.*, each combined set of lines can only be identified as controlled by one entity. Thus, if the 500 kV lines are owned or controlled by two different entities, there would have to be two line items for 500 kV lines listed in the appendix. We believe this approach will allow the Commission to continue to obtain the information it seeks regarding a seller's affiliated transmission assets while allowing those entities with a great number of assets to simplify their appendices.

381. Lastly, with regard to the asset appendix, we wish to make clear that sellers must submit both tables in their entirety. Even if a seller has no assets to list in a specific section, both the Market-Based Rate Authority and Generation Assets table, as well as the Electric Transmission Assets and/or Natural Gas Interstate Pipelines and/or Gas Storage Facilities table must be submitted. As stated in Appendix B to Order No. 697, a seller should indicate the fact that it has no assets or that a field is not applicable by inputting N/A.

4. Market-Based Rate Tariff Clarifications

382. In Order No. 697 the Commission adopted a requirement that all sellers include a provision in their market-based rate tariffs identifying all limitations on their market based rate authority (including markets where the seller does not have market-based rate authority) and any exemptions from, waivers of, or blanket authorizations under the Commission's regulations that the seller has been granted (such as exemption from the affiliate sales restrictions; waiver of the accounting regulations; blanket authority under part 34 for the issuances of securities and assumptions of liabilities). The Commission stated that this provision must include cites to the Commission orders approving each limitation, exemption, waiver or blanket authorization.[514] On further review, the Commission will take this opportunity to clarify several aspects of this requirement.

383. First, we clarify that if a seller's market-based rate authority is not subject to any limitations (for example, the seller's market-based rate authority is not limited to certain markets) or if the seller has not been granted any exemptions, waivers, or blanket authorizations under the Commission's regulations, then the seller should so state in the required ''Limitations and Exemptions'' provision in its market-based rate tariff, *i.e.*, including ''not applicable,'' or ''N/A.''[515]

384. Second, we provide additional guidance on the format for citations to pertinent Commission orders or proceedings in which the Commission imposed limitations on the seller's market-based rate authority or granted the seller's requested exemptions, waivers, or blanket authorizations. In particular, sellers which already have been granted market-based rate authorization and which have previously been placed under any limitation or granted any exemption, waiver or blanket authorization should include the cite to the relevant orders in one of the following two citation forms:

Cal. Contract Power, 99 FERC ¶ 61,xxx, at P xx (2002).

WWW Corp., Docket No. ER03–xxxx–000, at 2 (Apr. 12, 2003) (unpublished letter order).

385. When a seller files an application for market-based rate authority seeking certain exemptions, waivers or blanket authorizations, the seller should include in its proposed tariff sheets the docket number associated with the filing. Under current Commission procedure, a docket number is not assigned until after an application has been filed. However, to enable an applicant to identify and include the docket number of its filing in its proposed tariff sheets, the Commission is establishing a new process for sellers to obtain a docket number for their submission before filling. The Commission is creating a location on its Web site where a new applicant for market-based rate authorization will e-mail[516] the Commission and retrieve a docket number under which its filing can be made and which will be a substitute for the required citation in the ''Limitations and Exemptions'' provision of its tariff.[517] The point of this process is to

[514] Order No. 697 at P 916.

[515] *See Niagara Mohawk Power Corp.*, 121 FERC ¶ 61,275 at P11 (2007) (*Niagara Mohawk*).

[516] Any sellers unable to obtain this docket number via the internet or e-mail will be directed to include the pertinent information in their tariff sheets in a compliance filing.

[517] We note that while this approach will allow most new applicants to comply with the Commission's citing requirement in the ''Limitations and Exemptions'' provision of the

alleviate the need for compliance filings just to add a docket number or citation once the Commission issues an order on the request. Any modifications to the information submitted with the application would be directed to be made in a compliance filing. Once the docket number is obtained, the filing must be submitted to the Commission within 72 hours or the docket number will expire and the applicant must request a new one. This reserved docket number should be included in the tariff and the transmittal sheet, and a copy of the Commission's response assigning this docket number should be attached as the first page of the filing. Accordingly, the process for a seller newly filing for market-based rate authorization will now require reserving a docket number before submitting the filing.

386. In Appendix C of Order No. 697, the Commission provided certain applicable tariff provisions that sellers must include in their market-based rate tariffs to the extent they are applicable based on the services provided by the seller. One of these is to be used if a seller makes sales of ancillary services as a third-party provider.[518] We are revising this applicable provision so that it is consistent with the other ancillary service provisions by inserting the phrase ''Seller offers.'' Thus, the ''Third Party Provider'' provision that should be included in all applicable market-based rate tariffs is as follows:

Third-party ancillary services: Seller offers [include all of the following that the seller is offering: Regulation Service, Energy Imbalance Service, Spinning Reserves, and Supplemental Reserves]. Sales will not include the following: (1) Sales to an RTO or an ISO, *i.e.*, where that entity has no ability to self-supply ancillary services but instead depends on third parties; (2) sales to a traditional, franchised public utility affiliated with the third-party supplier, or sales where the underlying transmission service is on the system of the public utility affiliated with the third-party supplier; and (3) sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers.

387. Additionally, regarding other applicable tariff provisions, which include those needed if a seller makes sales of ancillary services in certain RTO/ISOs, the seller must include the standard ancillary services provision(s) in its tariff, as applicable, without variation.[519] To the extent that a seller with market-based rate authority does not already have authority to make sales of ancillary services at market-based rates in one or more of the RTO/ISOs included in Appendix C, but wishes to do so, it may file revised tariff sheets including the standard applicable ancillary service tariff provision(s) without seeking separate authorization from the Commission under FPA section 205. Separate authorization for specific sellers is not needed given that Order No. 697 implicitly granted authorization for ancillary services sales by sellers with market-based rate authority by providing standard tariff provisions for ancillary services sales.[520]

388. The Commission also stated in Order No. 697 that it would permit sellers to list in their market-based rate tariffs additional seller-specific terms and conditions that go beyond the standard provisions set forth in Appendix C.[521] In the Clarification Order, we clarified that these seller-specific terms and conditions do not include those provisions that the Commission has codified in 18 CFR Part 35, Subpart H. Specifically, we stated that '' 'seller-specific terms and conditions' are those provisions that are commonly found in power sales agreements, such as creditworthiness, force majeure, dispute resolution, billing, and payment provisions.'' [522] In addition, we clarify here that we expect that all provisions that were contained in a seller's market-based rate tariff but that are now codified in the Commission's regulations are to be removed from each seller's market-based rate tariff at the time the seller modifies its existing tariff to include the required provisions and any applicable provisions set forth in Appendix C of Order No. 697. For example, sellers should remove from their tariffs codes of conduct (which have been replaced by the affiliate restrictions in § 35.39), any language prohibiting affiliate sales without first receiving Commission authorization (which is codified in § 35.39(b)), market behavior rules (which are codified in § 35.41), and the change in status reporting requirement (which is codified in § 35.42).

389. We remind sellers that, consistent with § 35.9(b)(4), all tariff sheets must include a proposed effective date. The regulation requires that the seller must place the specific effective date proposed by the company on the tariff sheets. To alleviate any confusion, we stated in the Clarification Order that, notwithstanding the fact that Order No. 697 did not require market-based rate sellers to make immediate compliance filings amending their market-based rate tariffs, the Commission intended that all requirements and limitations applicable to market-based rate sellers set forth in the Final Rule should become effective on September 18, 2007. The Clarification Order explained that, effective September 18, 2007, provisions in market-based rate tariffs that are inconsistent with the requirements of Order No. 697 are no longer in effect.[523] Accordingly, sellers filing revised tariff sheets solely to comply with Order No. 697 should use September 18, 2007 as the effective date of the tariff sheets. However, if there are any additional revisions other than those required by the Final Rule, whether it be a name change or the addition or modification of any provision for any other reason, sellers should propose the date on which they wish the tariff sheets to become effective. We note that, while the sheets will be made effective on the date that the seller proposes, the provisions relating to and required by Order No. 697 are still effective as of the effective date of Order No. 697.[524]

390. Additionally, the Commission provides clarification regarding requests for waiver of affiliate restrictions (including the affiliate sales restriction and what was formerly the codes of conduct). If a seller was granted waiver of a restriction by the Commission prior to the effective date of Order No. 697, and the seller still qualifies for that waiver, the waiver remains effective and no further action is needed.[525] However, if a seller has not previously been granted waiver of the affiliate restrictions and seeks a finding that the affiliate restrictions do not apply to it, a seller must file a request with the

market-based rate tariff, there may be some instances in which the Commission will require a seller to make a subsequent filing to include a full citation to the Commission order approving a limitation, exemption, waiver or blanket authorization. An example of when the Commission may require such a compliance filing is when the Commission exempts a seller from affiliate restrictions which have been codified in 18 CFR 35.39 or when approving mitigation measures. However, unless an applicant is informed by order to revise its tariff to include a citation, the docket number used in the tariff in the initial submission will suffice.

[518] *See* Order No. 697 at P 917–18.

[519] *Id.* P 916–917; *see* Appendix C for a listing of the standard ancillary services provisions. *See also Niagara Mohawk Power Corp.*, 121 FERC ¶ 61,275, at P 14 & n.22 (2007) (directing seller to conform with Appendix C).

[520] *See Niagara Mohawk Power Corp.*, 121 FERC ¶ 61,275, at P 18 (2007) (accepting tariff provisions that were new for National Grid that comported with ancillary services previously approved by the Commission for sale at market-based rates and were listed in Appendix C of Order No. 697).

[521] Order No. 697 at P 919–22.

[522] Clarification Order, 121 FERC ¶ 61,260 at P15.

[523] *Id.* at P 5.

[524] *See* Clarification Order, 121 FERC ¶ 61,260 at P 5.

[525] Pursuant to Order No. 697, however, such a waiver must be identified in a seller's tariff. *See* Order No. 697 at P 916 and Appendix C.

Commission pursuant to FPA section 205.

391. Lastly, in order to identify which sellers must file updated market power analyses, we will now require each seller to specify in its market-based rate tariff whether it is a Category 1 or Category 2 seller. In a separate provision of the market-based rate tariff entitled Seller Category, each seller should state whether it believes it is in Category 1 or Category 2.[526] Specifically, the following provision should be included in each market-based rate tariff:

Seller Category: Seller is a [insert Category 1 or Category 2] seller, as defined in 18 CFR 35.36(a).

392. The Commission will make a finding on the category of each seller. To the extent that the Commission finds that a seller is in the other category, the Commission will order the appropriate tariff revisions.

393. Any seller whose category has been determined in a Commission proceeding between the effective date of Order No. 697 and the issuance of this order and which has not included a Seller Category provision in its tariff should update its tariff with such a provision the next time that it files revised tariff sheets, a triennial review, or a change in status report.

F. Legal Authority

1. Whether Market-Based Rates Can Satisfy the Just and Reasonable Standard Under the FPA

Final Rule

394. In the Final Rule, the Commission rejected arguments that it has no authority to adopt market-based rates or that the market-based rate program adopted in the Final Rule does not comply with the FPA. The Commission explained that it is settled law that market-based rates can satisfy the just and reasonable standard of the FPA, as most recently affirmed by the Ninth Circuit in *Lockyer* and *Snohomish*.[527] The Commission explained that in *Lockyer,* the Ninth Circuit cited with approval the Commission's dual requirement of an *ex ante* finding of the absence of market power and sufficient post-approval reporting requirements, finding that the Commission did not rely on market forces alone in approving market-based rate tariffs.[528] The Final Rule also rejected arguments that the proposed rule impermissibly relied solely on the market to determine just and reasonable rates, explaining that in the market-based rate program adopted in the Final Rule and through other Commission actions, the Commission is not relying solely on the market, without adequate regulatory oversight, to set rates.[529] Rather, it has adopted filing requirements, new market manipulation rules, and a significantly enhanced market oversight and enforcement division to help oversee potential increases in market power and potential market manipulation.[530]

395. The Commission retained its policy of granting market-based rate authority to sellers without market power under the terms and conditions set forth in the Final Rule.[531] The Final Rule explained that the Commission has a long-established approach when a seller applies for market-based rate authority of focusing on whether the seller lacks market power. The Commission explained that this approach, combined with the Commission's filing requirements (EQRs, change in status filings, and regularly scheduled updated market power analyses for Category 2 sellers) and ongoing monitoring through the Commission's Office of Enforcement and complaints filed pursuant to FPA section 206, allows the Commission to ensure that market-based rates remain just and reasonable. Moreover, for sellers in RTO/ISO organized markets, the Commission has in place market rules to help mitigate the exercise of market power, price caps where appropriate, and RTO/ISO market monitors to help oversee market behavior and conditions.[532]

396. The Final Rule rejected arguments that the market-based rate program does not comply with the FPA, stating that ''[t]he Supreme Court has held that '[f]ar from binding the Commission, the FPA's just and reasonable requirement accords it broad ratemaking authority * * *. The Court has repeatedly held that the just and reasonable standard does not compel the Commission to use any single pricing formula in general * * *.' ''[533] The Commission also pointed out that in the *Lockyer* court's analysis of the Commission's market-based rate authority, the Ninth Circuit cited the Supreme Court's determination in *Mobil Oil Exploration* and also noted that the use of market-based rate tariffs was first approved by the courts as to sellers of natural gas in *Elizabethtown Gas,* then as to wholesale sellers of electricity in *Louisiana Energy and Power Authority* v. *FERC*.[534]

397. The Commission rejected arguments that the Final Rule impermissibly relies solely on the market to determine just and reasonable rates.[535] The Final Rule explained that in *Texaco,*[536] the Supreme Court noted that it had sustained rate regulation based on setting area rates that were based on composite cost considerations, citing its decision in *FPC* v. *Hope Natural Gas Co.,*[537] and added that ratemaking agencies are not bound to the service of any single regulatory formula.[538] The Final Rule further explained that in *Texaco,* the Supreme Court found that the NGA permits the indirect regulation of small-producer rates, and noted that cases under the NGA and the FPA are typically read *in pari materia.*[539] The Commission stated that in the market-based rate program adopted in the Final Rule and through other Commission actions, unlike the situation in *Texaco,* the Commission is not relying solely on the market without adequate regulatory oversight to set rates.

398. The Final Rule also explained that in *Elizabethtown Gas,* a decision relying on *Texaco,* the D.C. Circuit addressed a Commission order approving a restructuring settlement under which Transcontinental Gas Pipeline Corporation (Transco) would no longer sell gas bundled with transportation, but would sell gas at the wellhead or pipeline receipt point, to be transported as the buyer sees fit, and the sales would be market-based while the rates for transportation on Transco's system would be cost-of-service

[526] Sellers that have received an exemption from Category 2, as described in Order No. 697 at P 868, should identify themselves as Category 1 sellers.

[527] Order No. 697 at P 943 (citing *State of California, ex rel. Bill Lockyer* v. *FERC*), 383 F.3d 1006 (9th Cir. 2004), *cert. denied* (S. Ct. Nos. 06–888 and 06–1100 (June 18, 2007) (*Lockyer*); *Public Utility District No. 1 of Snohomish County, Washington* v. *FERC,* 471 F.3d 1053 (9th Cir. 2006), cert. granted, 128 S. Ct. 31 (Sept. 25, 2007) (Nos. 06–1457, 06–1462) (*Snohomish*)).

[528] *Id.* P 953–954.

[529] *Id.* P 952.

[530] *Id.*

[531] *Id.* P 954–955.

[532] *Id.* P 955.

[533] *Id.* P 943 (quoting *Mobil Oil Exploration* v. *United Distribution Co.,* 498 U.S. 211, 224 (1991) (*Mobil Oil Exploration*), citing *FPC* v. *Hope Natural Gas Co.,* 320 U.S. 591, 602 (1944); *FPC* v. *Natural Gas Pipeline Co.,* 315 U.S. 575, 586 (1942); *Permian Basin Area Rate Cases,* 390 U.S. 747, 776–77 (1968) (*Permian*); *FPC* v. *Texaco,* 417 U.S. 380 (1974) (*Texaco*)).

[534] *Elizabethtown Gas Co.* v. *FERC,* 10 F.3d 866 (D.C. Cir. 1993) (*Elizabethtown Gas*); *Louisiana Energy and Power Authority* v. *FERC,* 141 F.3d 364 (D.C. Cir. 1998) (*LEPA*). *See also* Order No. 697 at P 944.

[535] Order No. 697 at P 945–947.

[536] *Id.* P 946 (citing *FPC* v. *Texaco, Inc.,* 417 U.S. 380 (1974) (*Texaco*)).

[537] *Id.* (citing 320 U.S. 602).

[538] *Id.* (quoting *Permian,* 390 U.S. at 776–77).

[539] *Id.* P 946 n.1070 (citing *FPC* v. *Sierra Pacific Power Co.,* 350 U.S. 348, 353 (1956) (*Sierra*); *Arkansas-Louisiana Gas Company* v. *Hall,* 453 U.S. 571 n.7 (1981)).

based.[540] In rejecting arguments that the proposed rule impermissibly relied solely on the market to determine just and reasonable rates, the Final Rule explained that in *Elizabethtown Gas* the D.C. Circuit upheld the Commission's approval of market-based pricing.[541] The Final Rule explained that the D.C. Circuit had also affirmed the Commission's approval of an application by Central Louisiana Electric Company (CLECO) to sell electric energy at market-based rates.[542]

Requests for Rehearing

399. Consumer Advocates argue that the Final Rule erred in claiming that the Commission can legally rely on the market (*viz.* wholesale buyers/re-sellers) to determine lawful rates. They contend that the Final Rule errs in relying on wholesale buyers/re-sellers to determine lawful rates by ''negotiation,'' particularly where the buyers generally bear no risk of loss in passing along such prices.[543] They argue that such reliance constitutes an unlawful delegation of the Commission's statutory obligations to wholesale buyers insofar as (1) the Commission overlooked the economic fact that such wholesale buyers/re-sellers generally bear no risk of loss because their negotiated prices must be passed through to retail ratepayers; [544] and (2) the Final Rule may not rely on the markets to determine rates because the Commission may not delegate to others its FPA responsibilities to ensure that rates are lawful.[545]

400. Consumer Advocates contend that the Final Rule failed to provide a standard whereby the Commission can determine whether actual market rate increases fall within a ''zone of reasonableness'' not just in theory, but ''in fact.'' According to Consumer Advocates, the Final Rule only addressed whether the ''market'' is competitive [546] and sellers are manipulative, not whether wholesale rates are not excessive, as the FPA requires.[547] Consumer Advocates argue that the Final Rule attempted to distinguish Supreme Court and other judicial precedent that requires the Commission to determine whether ''market'' rates in fact fall within a ''zone of reasonableness,'' but fails to do so.[548] They also contend that the Final Rule failed to explain how the Commission, which is not an antitrust agency, acting under the FPA, which is not an antitrust statute but a rate filing regulatory statute, can rely entirely on its oft-changing antitrust analyses regarding market power to determine whether market-based rates are within a zone of reasonableness.[549] NASUCA also asserts that the Final Rule failed to identify an objective standard by which to ascertain, after rates have been changed, charged and eventually reported, whether a market rate is or is not in the zone of reasonableness.[550]

401. Consumer Advocates contend that the Final Rule erred in relying heavily on Natural Gas Act (NGA) cases and Interstate Commerce Act oil pipeline cases as judicial support for the Commission's authority to allow market-based rates.[551] Consumer Advocates assert that there are substantive differences among electricity and natural gas statutes, the physical operations of the industries, and the costs of providing service.[552] They argue that in addition to the fact that Congress has deregulated most natural gas wellhead sales, but has never deregulated wholesale electric sales, the FPA and NGA have always differed in certain respects, namely that NGA section 7 confers authority on the Commission to certify and condition natural gas service, whereas no such authority is given to the Commission under the FPA.[553] Consumer Advocates argue that the regulation of generation and distribution was specifically reserved to the states [554] and contend that the costs of production of natural gas and electricity differ markedly.[555] They state that highly depreciated power plants have very different costs from new ones, and they note that in the Connecticut complaint against ISO New England, the complaint showed that excessive rates of return were being made, but the Commission found this '' 'not relevant.' '' [556]

402. Consumer Advocates conclude that these differences result in very different bidding strategies by market participants, yet the Final Rule relied primarily on natural gas and oil cases in defense of the Commission's market-based rate regime.[557] In particular, they contend that the claim in the Final Rule that ''costs of all natural gas companies need not be ascertained separately,'' incorrectly cites to the fact that the courts treat virtually identically parts of the statute '' '*in pari materia.*' '' [558] They argue that because this language refers to the filing and rate review provisions of the two statutes, it does not contend that the cost elements or physical operations of these two distinct industries are the same.[559]

403. Consumer Advocates argue that the incentive provided by the market-based rate regime is for plant owners to keep power supplies tight, thus raising their profits from remaining power plants or contracts.[560] They state that because wholesale sellers have no obligation to serve, the Commission's market-based rate regime requires the Commission to give incentives, like locational pricing, to essentially '' 'bribe' '' suppliers to build power plants.[561] Consumer Advocates contend that the Final Rule failed to explain why this '' 'perverse incentive' '' is in either the public or the national interest. They also note that the court in *Elizabethtown Gas* did not address these ''perverse economic incentives.'' [562]

404. Industrial Customers argue that a finding that competitive markets exist is a prerequisite to relying upon market-

[540] *Id.* P 948.

[541] *Id.* P 949–950.

[542] *Id.* P 951 (citing *LEPA,* 141 F.3d at 365).

[543] Consumer Advocates Rehearing Request at 10. Richard Blumenthal, Attorney General for the State of Connecticut and the People of the State of Illinois, by and through the Illinois Attorney General, Lisa Madigan (Attorneys General of Connecticut and Illinois) submitted a request for rehearing on July 19, 2007 that adopts and incorporates by reference all of the arguments presented by the Consumer Advocates in their request for rehearing filed in this proceeding.

[544] *Id.* at 10 (citing *Tejas Power Corp* v. *FERC,* 908 F.2d 998 (D.C. Cir. 1990); *Nantahala Power & Light Co.* v. *Thornburg,* 476 U.S. 953, 970 (1986); *Elizabethtown Gas*).

[545] *Id.* at 10, 12. Consumer Advocates note that in a recent order the Commission correctly held that it could not delegate to state commissions its ''ratemaking obligations under the FPA.'' *Id.* at 12 (citing *Entergy Services, Inc.,* 120 FERC ¶ 61,020 (2007), citing *Louisiana, Inc.* v. *Louisiana Public Service Comm.,* 539 U.S. 39, 43 n.1; *City of New Orleans* v. *Entergy Corp.,* 55 FERC ¶ 61,211, at 61,729 (1991)).

[546] As discussed at P 409 below, the Industrial Customers argue that the Final Rule erred insofar as it failed to make the finding that a competitive market exists. *See* Industrial Customers Rehearing Request at 6–7.

[547] Consumer Advocates Rehearing Request at 12–13.

[548] *Id.* (citing *Farmers Union Cent. Exch.* v. *FERC,* 734 F.2d 1486 (D.C. Cir. 1984) (*Farmers Union*)).

[549] *Id.* at 13–14 (citing *MCI Telecommunications Corp.* v. *AT&T Co.,* 512 U.S. 218 (1994) (*MCI*); *Southwestern Bell Corp.* v. *FCC,* 43 F.3d 1515 (D.C. Cir. 1995) (*Southwestern Bell*)).

[550] NASUCA Rehearing Request at 18.

[551] Consumer Advocates Rehearing Request at 19 (citing Order No. 697 at P 943, n. 1068 (citing *Mobil Oil Exploration,* 498 U.S. at 224, citing *FPC* v. *Hope Natural Gas Co.,* 320 U.S. 591, 602 (1944); *FPC* v. *Natural Gas Pipeline Co.,* 315 U.S. 575, 586 (1942); *Permian,* 390 U.S. at 776–77; *Texaco,* 417 U.S. at 308)).

[552] *Id.* at 17–18.

[553] *Id.* at 18.

[554] *Id.* (citing FPA section 201(e)).

[555] *Id.*

[556] *Id.* at 19 (citing *Richard Blumenthal* v. *ISO New England, Inc.,* 117 FERC ¶ 61,038 (2006), *reh'g denied,* 118 FERC ¶ 61,205 (2007) (*Blumenthal*)).

[557] *Id.* (citing Order No. 697 at P 943, n. 1068).

[558] *Id.* (citing Order No. 697 at P 946, n. 1070).

[559] *Id.*

[560] *Id.* at 20.

[561] *Id.*

[562] *Id.* at 21.

based rate authority to satisfy the mandates of the FPA. In particular, Industrial Customers contend that the Final Rule does not reflect reasoned decisionmaking because it fails to address their argument stating that the Commission must find the existence of a competitive market before it can rely on market-based rate authority.[563] Additionally, Industrial Customers contend that the Final Rule is arbitrary, capricious and insufficiently supported in presuming that existing price setting mechanisms are competitive markets that will enable the use of market-based rate authority to ensure just and reasonable rates.[564] Industrial Customers argue that their NOPR comments relied on significant precedent for their argument that the Commission must point to ''empirical proof'' that competitive markets exist.[565] Industrial Customers state that although the Commission provides settled law supporting its conclusion that market-based rates can satisfy the just and reasonable standard of the FPA,[566] the issue posed by Industrial Customers was whether the Commission has made the necessary findings that a competitive market exists—and it has not.[567] Industrial Customers therefore assert that the Commission failed its responsibility to respond to their arguments,[568] and must either (1) explain why the case law underlying market-based rate authority no longer requires the prerequisite showing of competitive markets based on empirical proof, or (2) undertake the task of analyzing whether current wholesale electricity pricing mechanisms amount to a competitive market.[569] Industrial Customers argue that the key question the Commission failed to answer in the Final Rule is what constitutes a truly competitive market and whether there are any in the country sufficient to enable use of market-based rate authority.

405. Industrial Customers argue that as the Commission acknowledged in its approval of the Southwest Power Pool's Energy Imbalance Service Market, the process for assessing market-based rate authority is a two-part analysis: (1) Determining whether a competitive market exists and (2) ensuring that the seller-applicant cannot exercise market power, based either on a finding that no market power exists or based on a finding that mitigation is sufficient to protect against market power.[570] Industrial Customers contend that if this two-part analysis is not undertaken, the Commission cannot demonstrate that reliance on market-based rate authority is just and reasonable.[571]

406. Industrial Customers state that there are definite criteria such as barriers to entry or exit, demand elasticity, ease of product deliverability, transparent market information, unconcentrated generation asset ownership, correct market design, and absence of market power that would help determine whether a competitive market exists.[572] They present information about existing markets that they allege calls into question whether the Commission is capable of finding the presence of dynamically competitive markets. Industrial Customers argue that the widespread lack of demand elasticity and the equally pervasive presence of generation ownership concentration and high market shares within submarkets are the types of issues that the Final Rule erroneously overlooked by presuming the existence of competitive markets.[573] Industrial Customers contend that market power issues are prevalent in PJM,[574] Midwest ISO,[575] Southwest Power Pool,[576] and ISO New England.[577]

Commission Determination

407. In the Final Rule, the Commission fully addressed the arguments raised by commenters challenging the Commission's market-based rate program. Consumer Advocates and Industrial Customers repeat on rehearing many of the arguments that they raised in their comments. While these entities re-state their arguments in a variety of ways, their arguments basically fall into two categories: (1) That the Commission has no authority at all under the FPA to rely on the market to ensure just and reasonable rates, in lieu of cost-based ratemaking; and (2) that the standard adopted by the Commission in this rule for allowing market-based rates—a demonstration by the individual seller that it lacks or has mitigated both horizontal and vertical market power—does not comply with the FPA requirement that rates be just, reasonable, and not unduly discriminatory or preferential. As we set forth below, we find all the iterations of these basic arguments to be without merit because court precedent for the past 60 years validates the Commission's discretion not to be bound to any particular ratemaking method and indeed in more recent years has sanctioned market-based rates under both the NGA and the FPA, and because the market-based rate analysis in this rule will result in rates that fall within a zone of reasonableness. Section 205 of the FPA requires that ''[a]ll rates and charges made * * * shall be just and reasonable.'' [578] The FPA does not prescribe any particular ratemaking methodology to be followed in setting rates so long as rates fall within a zone of reasonableness,[579] i.e., the rates are neither less than compensatory to the seller nor excessive to the consumer.[580]

[563] Industrial Customers Rehearing Request at 6 (citing *Electricity Consumers Res. Council* v. *FERC,* 747 F.2d 1511, 1513; *Burlington Truck Lines* v. *United States,* 371 U.S. 156, 168 (1962); *W. Mass Elec. Co.* v. *FERC,* 165 F.3d 922, 927 (D.C. Cir. 1997); *Victor Broad, Inc.* v. *FCC,* 722 F.2d 756, 760 (D.C. Cir. 1983); *Transcontinental Gas Pipe Line Corp.* v. *FERC,* 922 F.2d 865, 869 (D.C. Cir. 1991); *KN Energy, Inc.* v. *FERC,* 968 F.2d 1295, 1303 (D.C. Cir. 1992); *PPL Wallingford,* 419 F.3d at 1198; *Canadian Petroleum Producers,* 254 F.3d at 299; *Tesoro Alaska Petroleum Co.* v. *FERC,* 234 F.3d 1286, 1294 (D.C. Cir. 2000)). Montana Counsel similarly argues that the Commission erred in assuming that long-term markets are inherently competitive. Montana Counsel Rehearing Request at 4–6.

[564] *Id.* at 8 (citing *LEPA,* 141 F.3d at 365; *Elizabethtown Gas,* 10 F.3d at 870).

[565] *Id.* at 7 (citing Industrial Customers' August 7 Comments at 6–7; *Farmers Union,* 734 F.2d at 1510).

[566] *Id.* (citing Order No. 697 at P 943–955).

[567] *Id.*

[568] *Id.* (citing *NorAm Gas,* 148 F.3d at 1165; *Brusco Tug & Barge Co.* v. *NLRB,* 247 F.3d 273, 278 (D.C. Cir. 2001); *Missouri PSC* v. *FERC,* 234 F.3d 36, 41 (D.C. Cir. 2001)).

[569] *Id.* at 7–8 (citing *Tripoli Rocketry* v. *Bureau of Alcohol, Tobacco,* 437 F.3d 75, 81 (D.C. Cir. 2006)).

[570] *Id.* at 9 (citing *Southwest Power Pool, Inc.,* 116 FERC ¶ 61,289, at P 30 (2006)).

[571] *Id.*

[572] *Id.*

[573] *Id.* at 10.

[574] *Id.* at 10–13 (citing PJM 2006 State of the Market Report at 89, 210 (Mar. 8, 2007), *http://www.pjm.org*; PJM Preliminary Market Structure Screen for 2007–2008; PJM Preliminary Market Structure Screen for 2008–2009; PJM Preliminary Market Structure Screen for 2000–2010; Letter from PJM to Maryland Public Service Commission, dated June 8, 2007 at 8, Maryland PSC Administrative Docket No. PC 8; PJM 2008/2009 RPM Base Residual Auction Results at 1, (July 13, 2007); Statement of Joseph E. Bowring In Response to the Federal Energy Regulatory Commission's Order of May 18, 2007 at 3, (filed June 12, 2007)).

[575] *Id.* at 14 (citing 2006 Midwest ISO State of Market Report).

[576] *Id.* at 15 (citing Monthly Metrics Report for SPP Energy Imbalance Services Market at 3, prepared by the SPP Market Monitoring Unit (Apr. 2007)).

[577] *Id.* (citing ISO New England Report).

[578] 16 U.S.C. 824d(a).

[579] *FPC* v. *Hope Natural Gas Co.*, 320 U.S. at 602 (''[u]nder the statutory standard of 'just and reasonable' it is the result reached not the method employed which is controlling''); *Permian*, 390 U.S. at 776–77 (''rate-making agencies are not bound to the service of any single regulatory formula; they are permitted, unless their statutory authority otherwise plainly indicates, 'to make the pragmatic adjustments which may be called for by particular circumstances,' '' citing *FPC* v. *Natural Gas Pipeline Co.*, 315 U.S. at 586).

[580] *Bluefield Water Works and Improvement Co.* v. *Public Service Commission*, 262 U.S. 679, 692–

Further, the fixing of ''just and reasonable'' rates involves a balancing of investor and consumer interests[581] and the ''zone of reasonableness'' may take into account all relevant public interests, both existing and foreseeable.[582] These public interests may appropriately include non-cost factors, such as the need to stimulate additional investment.[583] As we explained in the Final Rule and reiterate here, the Supreme Court has held that ''[f]ar from binding the Commission, the 'just and reasonable' requirement accords it broad ratemaking authority * * *. The Court has repeatedly held that the just and reasonable standard does not compel the Commission to use any single pricing formula in general * * *.''[584] Accordingly, the FPA grants the Commission broad discretion as to how the statute's ratemaking mandate will be satisfied.[585] The market-based rate program represents a reasonable exercise of that discretion.[586]

408. It is settled law that market-based rates can satisfy the just and reasonable standard of the FPA and cognate statutes. For example, as the D.C. Circuit has held, ''when there is a competitive market the FERC may rely upon market-based prices in lieu of cost-of-service regulation to assure a 'just and reasonable' result.''[587] Thus, the Commission may rely on markets for a just and reasonable rate provided that it has made the appropriate findings regarding whether sellers lack market power.

409. The Commission exercises its statutory responsibility under the FPA to ensure that market-based rates are just and reasonable through the dual requirement of an *ex ante* finding that the seller lacks or has mitigated both horizontal and vertical market power and post-approval oversight through reporting requirements and ongoing monitoring.[588] In granting market-based rate authorization, the Commission thoroughly examines an applicant's market power in the relevant geographic markets. An examination of both horizontal (generation market share) and vertical (transmission and other barriers to entry) market power in the relevant markets gives the Commission assurance that the seller cannot increase price by restricting supply or denying customers access to alternative suppliers. When the Commission determines that a seller lacks or has mitigated market power, it is making a determination that the resulting rates will be established through competitive forces, not the exercise of market power, and thus will fall within a zone of reasonableness which protects customers against excessive rates, on the one hand, but allows the seller the opportunity to recover costs and earn a reasonable rate of return, on the other hand. This is fully consistent with the fundamental rate principles set forth in *Hope* and *Bluefield*, supra, and their progeny. In addition, in developing its market-based rate regime, the Commission has taken into account non-cost factors, recognized as appropriate by the courts, associated with greater reliance on competition; specifically, where sellers do not have market power, the Commission believes it can encourage greater market entry, greater efficiency and greater innovation in meeting the nation's power needs through allowing such sellers a competitively set rate.

410. Further, the Commission has in place multiple layers of protection for customers to ensure that market-based rates are just and reasonable and that they remain so. For public utilities selling in real-time and/or day-ahead markets administered by Commission-approved ISOs and RTOs (which cover five regions of the country), in addition to the market power analysis individual sellers must satisfy under this rule, sellers must comply with market rules contained in RTO/ISO tariffs approved by the Commission. These single price auction markets set clearing prices based on economic dispatch principles to which various safeguards have been added, as appropriate, including rules against improper bidding and, in some cases, bid price caps including conduct and impact tests. In addition, to ensure that market-based rates, once granted, remain just and reasonable and not unduly discriminatory or preferential, the Commission has incorporated filing and reporting requirements into the market-based rate program (EQRs, change in status filings, regularly-scheduled updated market power analyses). These filing requirements help the Commission to monitor potential gains in market power and to take remedial steps as appropriate, including revocation of market-based rate authority and civil penalties. The Commission has also required each of the RTO/ISOs to have market monitors to help oversee their wholesale markets and report to the Commission any concerns that market rules have been violated or concerns regarding seller behavior. This provides an added level of monitoring against the potential exercise of market power in the regional markets administered by the jurisdictional RTO/ISOs.

411. That market-based rates are permissible under FPA was recently affirmed by the Ninth Circuit in *Lockyer* and *Snohomish*. In *Lockyer*, the Ninth Circuit cited with approval the Commission's dual requirement of an *ex ante* finding of the absence of market power and sufficient post-approval reporting requirements and found that the Commission did not rely on market forces alone in approving market-based rate tariffs. The Ninth Circuit held that this dual requirement was ''the crucial difference'' between the Commission's regulatory scheme and the FCC's regulatory scheme, remanded in *MCI*, which had relied on market forces alone in approving market-based rate tariffs.[589] The Ninth Circuit thus held that ''California's facial challenge to market-based tariffs fails'' and ''agree[d] with FERC that both the Congressionally enacted statutory scheme, and the pertinent case law, indicate that market-based tariffs do not per se violate the FPA.''[590] The Ninth Circuit determined that initial grant of market-based rate authority, together with ongoing oversight and timely reconsideration of market-based rate authorization under

93 (1923) (Bluefield) (''[a] public utility is entitled to such rates as will permit it to earn a return * * * equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties'').

[581] *FPC* v. *Hope Natural Gas Co., 320 U.S. at 603.*

[582] *See Farmers Union*, 734 F.2d at 1501.

[583] *See id.* at 1502.

[584] *Id.* P 943 (quoting *Mobil Oil Exploration* v. *United Distribution Co.*, 498 U.S. 211, 224 (1991) (*Mobil Oil Exploration*), citing *FPC* v. *Hope Natural Gas Co.*, 320 U.S. 591, 602 (1944); *FPC* v. *Natural Gas Pipeline Co.*, 315 U.S. 575, 586 (1942); *Permian Basin Area Rate Cases*, 390 U.S. 747, 776–77 (1968) (*Permian*); *FPC* v. *Texaco*, 417 U.S. 380 (1974) (*Texaco*)).

[585] *Mobil Oil Exploration*, 498 U.S. at 224, citing *FPC* v. *Hope Natural Gas Co.*, 320 U.S. at 602; *FPC* v. *Natural Gas Pipeline Co.*, 315 U.S. at 586; *Permian*, 390 U.S. at 776–77; *Texaco*, 417 U.S. at 386–89; *Mobil Oil Corp.* v. *FPC*, 417 U.S. 283, 308 (1974).

[586] *Lockyer*, 383 F.3d at 1013; *Snohomish*, 471 F.3d at 1080.

[587] *Elizabethtown Gas*, 10 F.3d at 870. *See also Tejas Power*, 908 F.2d at 1004; *LEPA*, 141 F.3d at 365.

[588] *Lockyer*, 383 F.3d at 1013; *Snohomish*, 471 F.3d at 1080; *see also LEPA*, 141 F.3d at 370.

[589] *Lockyer*, 383 F.3d at 1013.

[590] *Id.* at 1013 & n.5; *id.* at 1014 (''The structure of the tariff complied with the FPA, so long as it was coupled with enforceable post-approval reporting that would enable FERC to determine whether the rates were 'just and reasonable' and whether market forces were truly determining the price.'').

section 206 of the FPA, enables the Commission to meet its statutory duty to ensure that all rates are just and reasonable.[591] While the court in *Lockyer* found that the Commission's market-based rate reporting requirements were not followed in that particular case, it did not find those reporting requirements invalid and, in fact, upheld the Commission's market program as complying with the FPA. The market-based rate requirements and oversight adopted in this rule are more rigorous than those reviewed by the *Lockyer* court.

412. Accordingly, we find to be without merit the arguments raised on rehearing that the Commission lacks authority to continue to permit market-based rates for wholesale sales of electric energy. The courts have sustained the Commission's finding that market-based rates are one method of setting just and reasonable rates under the FPA. As supplemented by the Final Rule, the Commission finds that the market-based rate program complies with the statutory and judicial standards for acceptable market-based rates. We address below the specific arguments raised on rehearing.

413. We reject Consumer Advocates' argument that the Commission's market-based rate program delegates to others the determination of lawful rates because it allows buyers and sellers to negotiate rates. The Commission, and no one else, undertakes the up-front analysis described above that a seller lacks or has mitigated market power and thus pre-determines that future rates charged by the seller will be just and reasonable. It is the Commission, not buyers and sellers, that makes the determination of whether and when negotiated rates will be lawful. It is also the Commission, not others, that makes a final determination with respect to any market rules or restrictions that must be put in place with respect to market-based rate sellers in RTO/ISO markets.

414. Thus, contrary to Consumer Advocates' claim, the Commission has not ''delegat[ed] to wholesale buyers'' its ratemaking obligations under the FPA.[592] Consumer Advocates contend that the Commission held that it could not delegate to state commissions its ''ratemaking obligations under the FPA,'' and that it could not delegate such rate determinations to ''jurisdictional utilities.'' [593] However, the case relied on by Consumer Advocates is distinguishable from the issue here. In *Entergy*, the Commission denied Entergy's petition for a declaratory order requesting that the Commission find that, where a resource to be acquired or constructed by one or more of the Entergy Operating Companies has met certain approval requirements, including a public interest finding by such retail regulators as may have jurisdiction, the resource shall be a system resource and all costs of such facility may be reflected in the applicable formula rates. The Commission concluded that there was no local interest comparable to that present in the cases relied on by Entergy, and therefore denied Entergy's request to delegate to state commissions, and to Entergy itself, the determination of the reasonableness of Entergy's Commission jurisdictional rates.[594] By contrast, in the instant rulemaking proceeding, the Commission is not delegating to a state commission or to a utility the determination of the reasonableness of Commission jurisdictional rates. Rather, as explained above, in granting market-based rate authority, the Commission exercises its statutory responsibility under the FPA to ensure that market-based rates are just and reasonable through the dual requirement of an *ex ante* finding of the absence of market power and post-approval oversight through reporting requirements and ongoing monitoring.

415. Additionally, with respect to Consumer Advocates' argument that the Commission has overlooked the economic fact that wholesale buyers/re-sellers do not bear the risk of loss because the prices paid by wholesale buyers/re-sellers ''must be passed through to retail ratepayers,'' not only is this argument irrelevant to whether the Commission has legal authority to permit market-based rates as just and reasonable under the FPA, the argument also is not accurate.[595] It is true that only the Commission has the authority to determine the justness and reasonableness of a public utility's wholesale rates and that a state cannot disallow pass-through in retail rates on the basis that it disagrees with the Commission's just and reasonable determination. However, the Commission has consistently recognized that wholesale ratemaking does not, as a general matter, determine whether a purchaser has prudently chosen among available supply options.[596]

416. In most circumstances ''a state commission may legitimately inquire into whether the retailer prudently chose to pay the FERC-approved wholesale rate of one source, as opposed to the lower rate of another source.'' [597] It is in the narrow situation where the Commission, in setting a wholesale rate, leaves the purchaser no legal choice but to purchase a specified amount of power that such determinations would be precluded.[598] Thus, we reject Consumer Advocates' arguments that these cases are relevant to the issue at hand.

417. We also reject Consumer Advocates' and NASUCA's arguments that the Final Rule failed to provide an objective standard under which the Commission can determine whether rate increases fall within a ''zone of reasonableness.'' [599] As part of their argument on rehearing, they again contend that markets alone cannot be relied on to set just and reasonable rates. As we explained in the Final Rule and reiterated above, the courts have sustained the Commission's finding that

[591] *See Snohomish*, 471 F.3d at 1080 (in which the Ninth Circuit discusses its decision in *Lockyer*). In *Snohomish*, the Ninth Circuit explained, ''As in *Lockyer*, we do not dispute that FERC may adopt a regulatory regime that differs from the historical cost-based regime of the energy market, or that market-based rate authorization may be a tenable choice if sufficient safeguards are taken to provide for sufficient oversight.'' *Id.* at 1086.

[592] Consumer Advocates Rehearing Request at 10, 12 (citing *Entergy Services, Inc.*, 120 FERC ¶ 61,020 (2007) (*Entergy*), citing *Louisiana, Inc.* v. *Louisiana Public Service Comm.*, 539 U.S. 39, 43 n.1; *City of New Orleans* v. *Entergy Corp.*, 55 FERC ¶ 61,211, at 61,729 (1991)).

[593] Consumer Advocates Rehearing Request at 12.

[594] *Entergy Services, Inc.*, 120 FERC ¶ 61,020 (2007).

[595] *Id.* at 10.

[596] *See Philadelphia Electric Co.*, 15 FERC ¶ 61,264, at 61,601 (1981); *Pennsylvania Power & Light Co.*, 23 FERC ¶ 61,006, *order on reh'g*, 23 FERC ¶ 61,325, at 61,716 (1983) (''We do not view our responsibilities under the Federal Power Act as including a determination that the purchaser has purchased wisely or has made the best deal available.''); *Southern Company Service*, 26 FERC ¶ 61,360, at 61,795 (1984); *Pacific Power & Light Co.*, 27 FERC ¶ 61,080, at 61,148 (1984); *Minnesota Power & Light Co.*, 43 FERC ¶ 61,104, at 61,342–43, *reh'g denied*, 43 FERC ¶ 61,502, *order denying reconsideration*, 44 FERC ¶ 61,302 (1988); *Palisades Generating Co.*, 48 FERC ¶ 61,144, at 61,574 and n.10 (1989).

[597] *Pike County Light & Power Co.* v. *Pennsylvania Public Utility Comm'n*, 465 A.2d 735, 738 (1983) (Pike County) (finding that while the state cannot review the reasonableness of the wholesale rate set by the Commission, it may determine whether it is in the public interest for the wholesale purchaser whose retail rates it regulates to pay a particular price in light of its alternatives). The Supreme Court's decisions in *Nantahala*, 476 U.S. 953 and *Mississippi Power & Light Co.* v. *Mississippi ex rel. Moore*, 487 U.S. 354 (1988) do not preclude, in every circumstance, state regulators from reviewing the prudence of a utility's purchasing decisions. *See*, e.g., *Kentucky West Virginia Gas Co.* v. *Pennsylvania Public Utility Comm'n*, 837 F.2d 600, 609 (3d Cir.) *cert. denied*, 488 U.S. 941 (1988) (*Kentucky West Virginia*); *Doswell Limited Partnership*, 50 FERC ¶ 61,251, at 61,758 n.18 (1990).

[598] *Nantahala*, 476 U.S. 953; *Mississippi Power & Light Co.* v. *Mississippi ex rel. Moore*, 487 U.S. 354 (1988) (*Mississippi Power*).

[599] Consumer Advocates cite several court cases in support of their argument in this regard. We address these cases in detail below.

market-based rates are one method of setting just and reasonable rates under the FPA.[600] Before granting a seller market-based rate authority, the Commission requires the seller to demonstrate that it and its affiliates lack or have adequately mitigated market power in relevant markets. The Commission undertakes a complete analysis of the seller's horizontal and vertical market power in the relevant markets and permits negotiated rates only if the seller demonstrates that it lacks or has mitigated market power. While this is not the same ''objective standard'' as cost-of-service ratemaking, which calculates the seller's costs and determines a specific rate of return, it nevertheless provides an objective standard for analyzing a seller's ability to exercise market power and thus determine whether rates will fall within a zone which is not excessive to customers and which allows the seller a reasonable opportunity to recover costs and earn a reasonable rate of return. In addition, the Commission does not rely on the market without adequate oversight. It has adopted filing requirements (EQRs and change in status filings for all market-based rate sellers and regularly scheduled updated market power analyses for all Category 2 market-based rate sellers), market manipulation rules, and enhanced market oversight through its enforcement division to help oversee potential market manipulation.[601] This approach, combined with the opportunity for interested parties to file complaints pursuant to FPA section 206, allows us to ensure that market-based rates remain just and reasonable. On this basis, we conclude that the rates charged pursuant to the Commission's market-based rate program fall within the ''zone of reasonableness.'' [602]

418. Further, as explained in the Final Rule, we believe that the market-based rate program fully complies with judicial precedent.[603] In *Lockyer*, the Ninth Circuit cited with approval the Commission's dual requirement of an *ex ante* finding of the absence of market power and sufficient post-approval reporting requirements and found that the Commission did not rely on market forces alone in approving market-based rate tariffs.[604] In *Snohomish*, the Ninth Circuit again determined that the initial grant of market-based rate authority, together with ongoing oversight and timely reconsideration of market-based rate authorization under section 206 of the FPA, enables the Commission to meet its statutory duty to ensure that all rates are just and reasonable.[605]

419. We disagree with Consumer Advocates' argument that the ''Final Rule also fails to explain how FERC, which is not an antitrust agency, acting under the FPA, which is not an antitrust statute but a rate filing regulatory statute, can rely entirely on FERC's oft-changing antitrust analyses regarding 'market power' to determine whether 'market-based rates' are within a zone of reasonableness.'' [606] As explained in the section of the Final Rule addressing the Commission's horizontal market power analyses,[607] when the Commission determines whether an applicant may sell wholesale electric power at market-based rates, it evaluates whether a seller lacks, or has adequately mitigated, market power in a particular market. When the Commission determines that a seller lacks both horizontal and vertical market power, it is making a determination that the resulting rates will be established through competitive forces, not the exercise of market power. Thus, rates resulting from competitive forces will not be excessive to customers and will allow the seller the opportunity to earn a fair return. As we explained in the Final Rule and reiterate above, the courts have sustained the Commission's finding that market-based rates are one method of setting just and reasonable rates under the FPA. Further, market monitoring by both the RTO/ISO market monitors and by the Commission help ensure that rates remain within a zone of reasonableness. Thus, we reject Consumer Advocates' argument that the Commission has failed to explain how it ''determine[s] whether 'market-based rates' are within a zone of reasonableness.''

420. We also reject Consumer Advocates' contention that the Final Rule erroneously relied on NGA cases and Interstate Commerce Act oil pipeline cases. The most recent court cases affirming the Commission's market-based rate authority under the FPA cite to the very same NGA and Interstate Commerce Act oil pipeline cases that the Commission discusses in the Final Rule.[608] It is settled law that market-based rates can satisfy the just and reasonable standard of the FPA, as most recently affirmed by the Ninth Circuit in *Lockyer* and *Snohomish*.[609] The court in *Lockyer* expressly denied a ''facial challenge to market-based [rate] tariffs.'' [610] Further, the *Lockyer* court's analysis of the Commission's market-based rate authority acknowledged that the use of market-based tariffs was first approved by the courts as to sellers of natural gas in *Elizabethtown Gas*, then as to wholesale sellers of electric energy in LEPA.[611] The *Lockyer* court also cited the Supreme Court's determination in *Mobil Oil Exploration* that ''the just and reasonable standard does not compel the Commission to use any single pricing formula * * *.'' [612] Additionally, *Elizabethtown Gas*, a decision wherein the D.C. Circuit determined that markets were sufficiently competitive to preclude a pipeline from exercising market power to assure that prices were just and reasonable within the meaning of NGA section 4, was relied on by the D.C. Circuit in *LEPA*, a case in which the court affirmed the Commission's approval of an application by CLECO to sell electric energy at market-based rates under the FPA.[613] Accordingly, we find that the Commission did not err in citing NGA and Interstate Commerce Act oil pipeline cases in the Final Rule.

421. We also reject Consumer Advocates' argument that the Final Rule incorrectly cites cases supporting the proposition that ''[c]ases under the NGA and FPA are typically read *in pari materia*'' because this language refers to the filing and rate review provisions of the two statutes, not the different cost elements of the electric and natural gas industries.[614] *Sierra* and *Arkansas-Louisiana Gas Co.* v. *Hall*,[615] are correctly cited by the Final Rule for the proposition that cases under the NGA and FPA are typically read *in pari materia*. The Final Rule noted this proposition in its discussion of *Texaco*, a case in which the Supreme Court held that the NGA permits the indirect regulation of small-producer rates; however, in citing this proposition, the

[600] *Lockyer*, 383 F.3d at 1013; *Snohomish*, 471 F.3d at 1080; *see also LEPA*, 131 F.3d at 370.

[601] Order No. 697 at P 952, 967.

[602] *See Public Service Company of Indiana*, Opinion No. 349, 51 FERC ¶ 61,367 at 62,226 (determining that market-based rate pricing resulted in rates that were within the zone of reasonableness and concluding that such pricing resulted in just and reasonable rates), *order on reh'g*, Opinion No. 349–A, 52 FERC ¶ 61,260, *clarified*, 53 FERC ¶ 61,131 (1990), *dismissed, Northern Indiana Public Service Company* v. *FERC*, 954 F.2d 736 (D.C. Cir. 1992).

[603] *Id.* P 943–955.

[604] *Lockyer*, 383 F.3d at 1013.

[605] *Snohomish*, 471 F.3d at 1080.

[606] Consumer Advocates Rehearing Request at 13.

[607] *See*, e.g., Order No. 697 at P 62–79.

[608] Order No. 697 at P 953; *see Lockyer*, 383 F.3d at 1011–1014.

[609] *Lockyer*, 383 F.3d at 1013; *Snohomish*, 471 F.3d at 1080.

[610] *Lockyer*, 383 F.3d at 1013.

[611] *Id.* at 1012 (citing *Elizabethtown Gas*, 10 F.3d at 870; *LEPA*, 141 F.3d at 365).

[612] *Id.* (citing *Mobil Oil Exploration*, 498 U.S. at 224).

[613] *LEPA*, 141 F.3d at 365 (citing *Elizabethown Gas*, 10 F.3d at 870).

[614] Consumer Advocates Rehearing Request at 19 (citing Order No. 697 at P 946, n.1070).

[615] 453 U.S. 571, 578 n.7 (1981).

Final Rule did *not* claim that the cost elements of the electric and natural gas industries are the same. Further, the Final Rule clearly explained that *Texaco* may be distinguished from the market-based rate regime set forth in the Final Rule, stating ''[i]n the market-based rate program adopted in this rule and through other Commission actions, unlike the situation in *Texaco*, the Commission is not relying solely on the market, without adequate regulatory oversight, to set rates.'' [616] Accordingly, Consumer Advocates' argument that the citation in the Final Rule to *Sierra* and *Arkansas-Louisiana Gas Co.* v. *Hall* is incorrect disregards the context in which these cases were cited.

422. We find Consumer Advocates' argument that the market-based rate regime gives plant owners an incentive to keep power supplies tight to raise their profits to be without merit. The two indicative horizontal market power screens, each of which serves as a cross-check on the other to determine whether sellers possess market power, take into account the availability of generating capacity. In particular, the first screen, the wholesale market share screen, measures for each of the four seasons whether a seller has a dominant position in the market based on the number of megawatts of uncommitted (available generation) capacity owned or controlled by the seller as compared to the uncommitted capacity of the entire relevant market.[617] The second screen is the pivotal supplier screen, which evaluates the potential of a seller to exercise market power based on uncommitted capacity at the time of the balancing authority area's annual peak demand. This screen focuses on the seller's ability to exercise market power unilaterally and examines whether the market demand can be met absent the seller during peak times.[618]

423. If there is not sufficient competing uncommitted capacity, a seller fails the pivotal supplier analysis, which creates a rebuttable presumption of market power.[619] Thus, through the use of the indicative horizontal market power screens, the Commission ensures that market-based rate sellers are not able to exercise market power and thereby should ensure that there is no incentive for plant owners to keep power supplies tight.[620]

424. Additionally, as a condition of obtaining and retaining market-based rate authority, a seller must timely report to the Commission any change in status that would reflect a departure from the characteristics the Commission relied upon in granting market-based rate authority. Thus, if a market-based rate seller acquires ownership or control of generation capacity that results in a net increase of 100 MW or more, or of inputs to electric power production, or ownership, operation or control of transmission facilities, or affiliation with any entity not disclosed in the application for market-based rate authority that owns or controls generation or transmission facilities or inputs to electric power production, the seller must report the change to the Commission so that the Commission may re-evaluate whether the seller is able to exercise market power.[621]

425. We reject Industrial Customers' argument that the Final Rule does not reflect reasoned decision-making because the Commission did not find the existence of a competitive market before relying on market-based rate authority. Under the FPA, the Commission is not bound to a particular ratemaking methodology in setting rates as long as rates fall within a zone of reasonableness,[622] *i.e.*, the rates are neither less than compensatory to the seller nor excessive to the consumer.[623] In addition, the ''zone of reasonableness'' may take into account all relevant public interests, both existing and foreseeable.[624] These public interests may appropriately include non-cost factors, such as the need to stimulate additional investment.[625] In permitting market-based rates in its regulation of electric markets, there are two approaches the Commission has used to ensure that rates are just and reasonable: Either a finding that an individual seller and its affiliates lack or have mitigated market power in a particular market; or a finding that a particular market is competitive or yields competitive results. Since the mid-1980's, the Commission's approach in the electric area has been primarily to rely on an analysis of individual seller market power, as was recently affirmed in the Final Rule. In addition, with regard to rates for sales within RTO/ISOs, even if sellers have been found to lack market power on an individual seller basis, the Commission has relied on a blend of market and cost-based elements, e.g., some form of cost cap or mitigated bids, to ensure just and reasonable rates.[626]

426. The Commission has previously considered a similar argument (that the Commission must find that a market is competitive before it can permit market-based rates) with regard to the Midwest ISO (MISO), and rejected it. We stated:

> The Commission rejects MISO Industrial Customers' argument that, as a prerequisite to reliance upon market-based rate pricing to produce just and reasonable rates, the

[616] Order No. 697 at P 952.

[617] *Id.* P 34 (citing April 14 Order, 107 FERC ¶ 61,018 at P 100).

[618] *Id.* P 35.

[619] *Id.* P 65.

[620] Consumer Advocates cite the Commission's decision in *Richard Blumenthal* v. *ISO New England, Inc.*, 117 FERC ¶ 61,038 (2006), *reh'g denied*, 118 FERC ¶ 61,205 (2007) (*Blumenthal*) to support their statement that ''in the Connecticut complaint against the ISO New England, the Complaint showed that excessive rates of return were being made, but the Commission found this 'not relevant.' '' Consumer Advocates Rehearing Request at 19. Consumer Advocates' argument in this regard is not clear because they do not explain how the fact-specific determinations made by the Commission in addressing the section 206 complaint at issue in *Blumenthal* relate to the Commission's policy of granting market-based rate authority to sellers without market power under the terms and conditions set forth in the Final Rule. In *Blumenthal*, the Commission denied a complaint filed against the ISO New England upon concluding that the complainants had not met their burden under section 206 to establish that the current provisions of the ISO New England's Market Rule 1 were unjust and unreasonable.

[621] 18 CFR 35.42.

[622] *FPC* v. *Hope Natural Gas*, 320 U.S. 591, 602 (1944) (''[u]nder the statutory standard of 'just and reasonable' it is the result reached not the method employed which is controlling''); *Permian*, 390 U.S at 776–777 (''rate-making agencies are not bound to the service of any single regulatory formula; they are permitted, unless their statutory authority otherwise plainly indicates, 'to make the pragmatic adjustments which may be called for by particular circumstances,' '' citing *FPC* v. *Natural Gas Pipeline Co.*, 315 U.S. 575, 586 (1942)).

[623] *Bluefield*, 262 U.S. at 692–93 (1923).

[624] *Farmers Union*, 734 F.2d at 1501 (citing *Permian*, 390 U.S. at 790 (''Congress delegated ratemaking authority to FERC in broad terms. Accordingly, 'the breadth and complexity of the Commission's responsibilities demand that it be given every reasonable opportunity to formulate methods of regulation appropriate for the solution of its intensely practical difficulties' '')).

[625] While the court in *Farmers Union* found that the Commission had failed to demonstrate that its ruling in the underlying orders would, in fact, stimulate new investment, the court acknowledged that such ''non-cost factors may legitimate a departure from a rigid cost-based approach.'' *Farmers Union*, 734 F.2d at 1502 (citing *FERC* v. *Pennzoil Producing Co.*, 439 U.S. at 518; *Mobil Oil Corp.* v. *FPC*, 417 U.S. at 308).

[626] *See* Order No. 697 at P 952. At the time the Commission approved the tariffs for ISO New England, the New York Independent System Operator, and PJM, it applied mitigation procedures in markets administered by those organizations, and incorporated those procedures in the RTO/ISO tariffs so as to apply to all sellers in the RTO/ISO administered markets. *See New England Power Pool*, 85 FERC ¶ 61,379 (1998); *Central Hudson Electric & Gas Corp.*, 86 FERC ¶ 61,062 (1999); *Atlantic City Electric Co.*, 86 FERC ¶ 61,248 (1999). *See also AEP Power Marketing, Inc.*, 109 FERC ¶ 61,276 (2004), *reh'g denied*, 112 FERC ¶ 61,320, at P 23 (2005) (after finding that AEP passed the generation market power screening test in PJM, the Commission also noted that ''RTOs such as PJM with Commission-approved market monitoring and mitigation provide a check on the exercise of generation market power''), *aff'd sub nom. Industrial Energy Users-Ohio* v. *FERC*, No. 05–1435, 2007 U.S. App. LEXIS 3661, at *2 (D.C. Cir. Feb. 16, 2007) (noting that ''the Commission adequately considered and responded to petitioner's arguments'') (unpublished).

Commission must, in addition to finding that applicants lack or have adequately mitigated market power, make a separate and independent finding that a competitive market exists. * * * We * * * incorporate by reference the Commission's discussion in its final rule on market-based rates (Order No. 697 [at P 943–71]) of the legality of its approach to market-based rates. The Commission's long-established approach involves assessing whether a seller lacks market power, which includes an assessment of seller-specific market power. This approach, combined with the Commission's filing requirements and ongoing monitoring, allows the Commission to ensure that market-based rates remain just and reasonable. Additionally, for sellers in RTO/ISO organized markets, the Commission has in place market monitoring and mitigation rules to mitigate the exercise of market power, including price caps where appropriate, and the Commission also uses RTO/ISO market monitors to help oversee market behavior and market conditions. * * *[627]

427. As we explained in the Final Rule, we retained our approach to determining whether a seller should receive authorization to charge market-based rates, as modified by the Final Rule, by analyzing seller-specific market power. We have a long-established approach when a seller applies for market-based rate authority of focusing on whether the seller lacks market power.[628]

428. We reject Industrial Customers' argument that the Final Rule is inconsistent with *Farmers Union* because that case requires the Commission to point to "empirical proof" that competitive markets exist.[629] The regulatory scheme at issue in *Farmers Union* is distinguishable from the Commission's market-based rate program. In *Farmers Union*, a case concerning rates for oil pipelines, the court found that the Commission "sought to establish maximum rate ceilings at a level far above the 'zone of reasonableness' required by the statute."[630] The court found that the Commission departed from established ratemaking principles when the Commission determined that oil pipeline rate regulation should "protect against only '*egregious* price exploitation and *gross* abuse'" by the regulated pipelines,[631] since "the cost of pipeline transportation, relative to the price of oil, had become so insignificant that close regulation was not required."[632] The court found error in the Commission's approach, finding that there was "only anecdotal evidence of intermodal competition on certain pipeline routes[,]"[633] and noted that the Commission's "evaluation of competition in the oil pipeline industry is not entirely clear."[634] The court concluded that "the fundamental flaw in the Commission's scheme" was that "nothing in the regulatory scheme itself acts as a monitor to see if [actual prices are driven back down into the zone of reasonableness] or to check rates if [prices are not driven down].[635] In this regard, the court also explained that:

> In setting extraordinarily high price ceilings as a substitute for close regulation, FERC assumed that, with the wide exposed zone between the ceiling and the 'true' market rate, existing competition would ensure that the actual price is just and reasonable. Without empirical proof that it would, this regulatory scheme, however, runs counter to the basic assumption of statutory regulation, that 'Congress rejected the identity between the 'true' and the 'actual' market price.'[636]

Thus, the court found that the fundamental flaw in the Commission's regulatory scheme in *Farmers Union* was that there was no monitoring.

429. The *Farmers Union* court found that the Commission's "largely undocumented reliance on market forces as the principal means of rate regulation" was misplaced.[637] In this regard, it noted that "when Congress amended the Interstate Commerce Act to account for competition in the rail carrier industry, the amendment required the ICC to make a specific finding that a particular rail carrier did not have 'market dominance' before deregulating the carrier. * * * We do not believe that the unamended oil pipeline rate provisions of the Interstate Commerce Act, which do not make any provision for deregulation, would require any less of a particularized showing before competition might be properly taken into account."[638] The court nonetheless concluded that "'non-cost' factors may play a legitimate role in the setting of just and reasonable rates."[639] It also found that "[m]oving from heavy to lighthanded regulation within the boundaries set by an unchanged statute can, of course, be justified by a showing that under current circumstances the goals and purposes of the statute will be accomplished through substantially less regulatory oversight."[640]

430. The defects that the court found to be present in the regulatory scheme under review in *Farmers Union* are not present in the Commission's market-based rate program. As an initial matter, in the case under review in *Farmers Union*, the Commission had not undertaken any analysis of the sellers participating in the oil pipeline industry as part of its decision to adopt a generic ratemaking methodology to be applied to all oil pipelines. Unlike *Farmers Union*, before granting a seller market-based rate authority, the Commission performs an initial evaluation to determine whether the seller or any of its affiliates has horizontal or vertical market power and, if so, whether such market power has been mitigated. The Commission only permits a seller to use market-based rate pricing if the Commission finds that the seller lacks, or has adequately mitigated, market power in the relevant market.

431. Similarly, unlike *Farmers Union*, where the court identified as a "fundamental flaw" the absence of any monitoring to ensure that rates remain within a zone of reasonableness, the market-based rate program does not rely solely on the market, without adequate regulatory oversight, to determine rates. Rather, the market-based rate program includes post-approval oversight through reporting requirements and ongoing monitoring. In addition, market monitoring by the Commission helps ensure that rates remain within a zone of reasonableness.[641] Thus, the Commission's market-based rate program does not contain the defects that the court found to be present in *Farmers Union*,[642] and is not arbitrary

[627] *Midwest Independent Transmission System Operator, Inc.*, 120 FERC ¶ 61,202 at P 9, 12 (2007).

[628] Order No. 697 at P 955 (citing *Heartland Energy Services, Inc.*, 68 FERC ¶ 61,223, at 62,060–61 (1994); *Louisville Gas and Electric Co.*, 62 FERC ¶ 61,016, at 61,143 n.16 (1993) (and the cases cited therein); *Citizens Power & Light Corp.*, 48 FERC ¶ 61,210, at 61,776 & n.11 (1989); *Pacific Gas and Electric Co. (Turlock)*, 42 FERC ¶ 61,406, at 62,194–98, *order on reh'g*, 43 FERC ¶ 61,403 (1988); *Pacific Gas and Electric Co.* (Modesto), 44 FERC ¶ 61,010, at 61,048–49, *order on reh'g*, 45 FERC ¶ 61,061 (1988). *See also*, e.g., *LEPA*, 141 F.3d at 365; *Consumers Energy Co.*, 367 F.3d 915, 922–23 (D.C. Cir. 2004) (upholding Commission orders granting market-based rate authority, noting that the Commission's longstanding approach is to assess whether applicants for market-based rate authority do not have, or have adequately mitigated, market power); *Lockyer*, 383 F.3d at 1012–1013.

[629] Industrial Customers Rehearing Request at 7.

[630] *Farmers Union*, 734 F.2d at 1501.

[631] *Id.* at 1502 (citation omitted; emphasis supplied by court).

[632] *Id.* at 1507.

[633] *Id.* at 1509.

[634] *Id.* n.50.

[635] *Id.* at 1509 (citation omitted).

[636] *Id.* at 1510.

[637] *Id.* at 1508 (footnote omitted).

[638] *Id.* at n. 50.

[639] *Id.* at 1503.

[640] *Id.* at 1510.

[641] On this basis, we find State AGs and Advocates' reliance on *Farmers Union* to support their argument that the Final Rule failed to provide a standard under which the Commission can determine whether rate increases fall within a "zone of reasonableness" to be misplaced.

[642] *See Midwest Independent Transmission System Operator, Inc.*, 120 FERC ¶ 61,202, at P 9, 12 (2007); *PJM Interconnection, L.L.C.*, 121 FERC ¶ 61,173, at P 22 (2007).

and capricious because, contrary to Industrial Customers' assertions, under the market-based rate program the Commission performs an initial evaluation of all sellers before granting market-based rate authority, and because the market-based rate program includes adequate oversight and monitoring.

432. Industrial Customers contend that the Final Rule is inconsistent with the Commission's decision in *Southwest Power Pool, Inc.* (*SPP*) where the Commission made a finding that the market was competitive before approving market-based rates for an energy imbalance service.[643] In *SPP*, the Commission found that the SPP imbalance market is competitive in the absence of transmission constraints, and that SPP's mitigation measures and monitoring plan are sufficient to protect customers from the exercise of market power that might occur in the energy imbalance market when transmission constraints bind.[644] We reject Industrial Customers' contention that the Commission may only grant market-based rate authorization if it first analyzes whether a competitive market exists. As explained above, the Commission has discretion[645] to rely on an analysis of individual seller market power, as was affirmed in the Final Rule, and the courts have upheld this approach.[646] Our use of this approach for SPP does not require its use elsewhere. At the same time, the Commission will allow RTO/ISOs to conduct market power studies that the RTO/ISO members can rely on in their market power filings, which will help ensure the accuracy and consistency of data.

433. With regard to Industrial Customers' contention that there are market power issues prevalent in the PJM, Midwest ISO, Southwest Power Pool, and ISO New England markets, we find that such issues are beyond the scope of this proceeding. The instant rulemaking proceeding codifies and revises the Commission's standards for market-based rates and streamlines the administration of the market-based rate program; however, this rulemaking is not intended to evaluate market power issues with regard to particular markets throughout the United States.

2. Consistency of Market-Based Rate Program With FPA Filing Requirements

a. Whether the Multiple Layers of Filing and Reporting Requirements Incorporated into the Market-Based Rate Program Provide Adequate Protection from Excessive Rates

Final Rule

434. In rejecting Consumer Advocates' arguments that the Commission's market-based rate program fails to comply with the FPA,[647] the Commission pointed out in the Final Rule that the FPA requires that every public utility file with the Commission "schedules showing all rates and charges for any transmission or sale subject to the jurisdiction of the Commission," but it explicitly leaves the timing and form of those filings to the Commission's discretion.[648] The Commission noted that the courts have recognized the Commission's discretion in establishing its procedures to carry out its statutory functions.[649] The Commission explained that the market-based rate tariff, with its appurtenant conditions and requirement for filing transaction-specific data in EQRs, is the filed rate.[650]

435. The Commission also disagreed with Consumer Advocates' arguments that the Commission failed to show how competitive market-based rates are just and reasonable and not unduly discriminatory or preferential, stating "the standard for judging undue discrimination or preference remains what it has always been: Disparate rates or service for similarly situated customers."[651] The Commission explained that rates do not have to be set by reference to an accounting cost of service to be just, reasonable and not unduly discriminatory, stating that when the Commission determines that a seller lacks market power, it is making a determination that the resulting rates will be established through competition, not the exercise of market power. The Commission also explained that courts have upheld the Commission's determinations that rates that are established in a competitive market can be just, reasonable and not unduly discriminatory.[652]

436. In the Final Rule, the Commission disagreed with Consumer Advocates' argument that the market-based rate program eliminates the statutory mandate that all rate increases be noticed by filing 60 days in advance and, if warranted, suspended for up to five months, set for hearing with the burden of proof on the seller, and made subject to refund pending the outcome of the hearing.[653] The Commission explained that it has developed a thorough process to evaluate the sellers that it authorizes to enter into transactions at market-based rates.[654] Under the market-based rate program, the rate change is initiated when a seller applies for authorization of market-based rate pricing. All applications are publicly noticed, entitling parties to challenge a seller's claims. At that time, there is an opportunity for a hearing, with the burden of proof on the seller to show that it lacks, or has adequately mitigated, market power, and for the imposition of a refund obligation.[655] Additionally, if a seller is granted market-based rate authority, it must comply with post-approval reporting requirements, including the quarterly filing of transaction-specific data in EQRs, change in status filings for all sellers, and regularly-scheduled updated market power analyses for Category 2 sellers.[656] In the Final Rule the Commission explained that it may, based on its review of EQR filings or daily market price information, investigate a specific utility or anomalous market circumstances to determine whether there has been any conduct in violation of RTO/ISO market rules or Commission orders or tariffs, or any prohibited market manipulation, and take steps to remedy any violations. These steps could include, among other things, disgorgement of profits and refunds to customers if a seller is found to have violated Commission orders, tariffs or rules, or a civil penalty.[657]

Requests for Rehearing

437. Consumer Advocates contend in their request for rehearing that the Final

[643] 116 FERC ¶ 61,289, at P 30 (2006), *appeal pending sub nom., Southwest Indus. Customer Coalition* v. *FERC*, No. 06–1390, *et al.* (D.C. Cir. Nov. 27, 2006).

[644] *Id.*

[645] *See* e.g., *Exxon Co., USA* v. *FERC*, 182 F.3d 30, 37–38 (D.C. Cir. 1999) (stating that where "the analysis to be preformed 'requires a high level of technical expertise, we must defer to the informed discretion of the responsible federal agencies.' ") (internal citation omitted); *Oxy USA, Inc.* v. *FERC*, 64 F.3d 679, 690–91 (D.C. Cir. 1995).

[646] *Lockyer*, 383 F.3d at 1013; *Snohomish*, 471 F.3d at 1080; *LEPA*, 141 F.3d at 370.

[647] Order No. 697 at P 959.

[648] *Id.* (quoting 16 U.S.C. 824d(c)).

[649] *Id.* P 960 (citing *Lockyer*, 383 F.3d at 1013; *Wabash Valley Power Association* v. *FERC*, 268 F.3d 1105, 1115 (D.C. Cir. 2001), *Environmental Action* v. *FERC*, 996 F.2d 401, 407–08 (D.C. Cir. 1993)).

[650] *Id.* P 961. The Commission further noted that it has held that if every service agreement under a previously-granted market-based rate authorization had to be filed prior to approval, then the original market-based rate authorization would be a pointless exercise. *Id.* (citing *GWF Energy LLC*, 98 FERC ¶ 61,330, at 62,390 (2002)).

[651] *Id.* P 963 (citing *Southwestern Electric Cooperative, Inc.* v. *FERC*, 347 F.3d 975, 981 (D.C. Cir. 2003)).

[652] *Id.* (citing *Lockyer*, 383 F.3d at 1012–13; *Tejas Power Corp.* v. *FERC*, 980 F.2d 998, 1004 (D.C. Cir. 1990)).

[653] *Id.* P 962.

[654] *Id.*

[655] *Id.*

[656] *Id.*

[657] *Id.* P 964.

Rule failed to provide a standard for determining prohibited undue preference or discrimination under the Commission's market-based rate regime.[658] In particular, Consumer Advocates argue that the traditional FPA section 205(b) standard has no apparent application to market-based rates because such rates, by definition, are allowed to be any rate for any service on which the seller and buyer agree, regardless of the relation of such prices or services to any other market-based rate or service.[659] Consumer Advocates assert that the Final Rule relies on buyers to negotiate non-excessive rates, and if the buyer is an affiliate or a competitor, the rationale supporting the idea that disinterested sellers and buyers will negotiate non-discriminatory rates, disappears altogether.[660] They also argue that the Final Rule does not provide a reason for why long-term affiliate sales service agreements should not be filed.[661] Consumer Advocates further argue that the Final Rule erred in assuming that the Commission's statutory role is to protect electricity markets, regardless of the impact on consumers.[662] They argue that the FPA was enacted to protect consumers from the market,[663] and that mere market incentives alone cannot be relied upon to protect the public interest.

438. Consumer Advocates contend that the Final Rule erred in finding that the Commission has legal authority to eliminate the Congressionally-mandated consumer protections of FPA section 205(e).[664] Specifically, they argue that the Final Rule continues to effectively define rate increases out of existence by claiming that none occur, and in so doing, eliminates the FPA-mandated prior rate filings and review of rate increases required by section 205(d).[665] Consumer Advocates argue that this definitional ploy eliminates both the Commission's and the consumers' ability to exercise their statutory rights under section 205(e) applying to rate increases, including the opportunity for suspension of excessive rates, hearings with the burden of proof on sellers to justify rate increases and with immediately effective refund with interest obligations for consumers who are found to have paid excessive rates.[666] Consumer Advocates contend that neither the Commission nor any court has the legal authority to gut these statutory protections for consumers against excessive rates, and the Final Rule erred in claiming such authority for either court or agency.[667]

439. Consumer Advocates argue that because rate increase filings are controlled by a different FPA provision, the Final Rule erred in relying on the Commission's discretion as to the form and timing of filings of initial rates as legal justification for eliminating prior filings of rate increases under market-based rate tariffs. They assert that the Final Rule relied on the Commission's discretion under section 205(c) as to the form and timing of rate schedule filings to legally justify eliminating the FPA-mandated filing of specific rates and rate increases, yet insisted that the filing of market-based rate tariff authorizations is a ''change'' in rate, and the filing of subsequent actual charges are merely filings in satisfaction of Commission-created '' 'reporting requirements.' ''[668] Consumer Advocates also contend that one serious flaw in this argument is that section 205(d), not section 205(c), controls '''changes''' in rates, and section 205(d) does not offer the same discretion as to the form and timing of rate increase filings.[669]

440. Consumer Advocates contend that the market-based rate tariff authorization application would be, as a change in rate, subject to section 205(d), not section 205(c). They argue that the relied-upon discretion provided does not apply to any market-based rate, because under the legal logic of the Final Rule there never are any initial market-based rates filed.[670] According to Consumer Advocates, the Lockyer decision also relied erroneously on the Commission's discretion under section 205(c) as authority to approve the Commission's elimination of section 205(d) prior filings of rate changes.[671] Consumer Advocates conclude that the Final Rule erred insofar as: (1) It failed to explain how the Commission's market-based rate authorization orders satisfy these plain requirements of section 205(d), which must apply to market-based rate tariff authorizations, as ''changes'' in rates; (2) market-based rate authorizations fail to specify either a change in the amounts to be charged or the time when such new charges will go into effect; and (3) all subsequent actual increases in charges under the market-based rate tariff, according to the Final Rule's logic, are not changes in the rate, but merely reports, or EQRs, no matter how dramatically actual prices increase.[672]

441. Consumer Advocates contend that the Final Rule claimed that the Commission can suspend the use of market-based rate tariffs when they are first filed, but does not try to justify either the consumer-protection rationale or the legal authority for its attempted elimination of the Commission's ability to suspend all subsequent excessive rate increases under market-based ''rates.''[673] Consumer Advocates contend that *Lockyer* acknowledges that the Commission's ability to suspend excessive rate increases is lost under the market-based rate regime, but appears to believe that the Commission can eliminate such protections if it so chooses.[674] Consumer Advocates state that *Lockyer* does not acknowledge the other consumer protections that are eliminated by the Commission's definition of ''change'' as including none of the specific rate charges filed as ''reports.'' They contend that loss of rate suspensions alone eliminates 8 months of potential consumer protection from excessive rates: 5 months of the Commission's lost ability to suspend rate increases and 3 months before the rates are even seen in reports and can be set for hearing under section 206.[675] Consumer Advocates assert that this result is directly contrary to Congress' intent in the Energy Policy Act of 2005[676] to extend the filing provisions of sections 205(c) and (d) to non-public transmitting utilities, and to reduce the time before section 206 rates can be made subject to refund.[677]

442. NASUCA argues that the Commission did not articulate an adequate legal basis to support the Final Rule's reduced market power review and filing requirements.[678] While

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[658] Consumer Advocates Rehearing Request at 14 (citing 16 U.S.C. 824d(b)).

[659] *Id.*

[660] *Id.* at 15.

[661] *Id.*

[662] *Id.* at 21–22.

[663] *Id.* at 22 (citing *Atlantic Ref. Co.* v. *Pub. Serv. Comm'n of State of N.Y.*, 360 U.S. 378, 388 (1959); *United Gas Pipe Line Co.* v. *Mobile Gas Service Corp.*, 352 U.S. 332 (1956) (*United Gas Pipe Line*); *Sierra*; *Electrical District No. 1* v. *FERC*, 774 F.2d 490 (D.C. Cir. 1985) (*Electrical District*).

[664] *Id.*

[665] *Id.*

[666] *Id.*

[667] *Id.*

[668] *Id.* at 23 (citing Order No. 697 at P 960; 962–63).

[669] *Id.*

[670] *Id.* at 23–24.

[671] *Id.* at 24 (citing *Lockyer,* 383 F.3d at 1013; Order No. 697 at P 960). Consumer Advocates state that section 205(d) requires that all rate increases and other changes in rates or charges must be filed 60 days in advance of being charged, unless the Commission for good cause issues an order ''specifying the changes'' to be made to the rates and charges, and specifying ''the time when the change or changes will go into effect.'' *Id.*

[672] *Id.* at 24–25.

[673] Consumer Advocates Rehearing Request at 31.

[674] *Id.* at 30.

[675] *Id.* at 31.

[676] Pub. L. No. 109–58, 119 Stat. 594 (2005).

[677] Consumer Advocates Rehearing Request at 31 (citing 119 Stat. 594 sections 1285 and 1290(a)(2)).

[678] NASUCA Rehearing Request at 17.

NASUCA notes that the Final Rule responded to its concerns, citing the decision of the Ninth Circuit in *Lockyer* and relying on FPA section 205(c) as authority to adjust the timing of rate filing, [679] NASUCA contends that the adjacent statutory language of section FPA 205(d) limits that power.[680] NASUCA argues that ''[t]he 'crucial difference' between impermissible exclusive reliance on market rates found in the *Lockyer* decision * * * is absent in the revisions made in the Final Rule.'' [681] NASUCA also contends that the Ninth Circuit mistakenly believed that the Commission looks at a seller's market power reviews in triannual reviews, *i.e.,* conducted once every four months, rather than triennial reviews, *i.e.,* once every three years.[682] NASUCA concludes that the actions being taken to streamline filing requirements eliminate market power reviews for many sellers, and that to rely mainly on a *post hoc* monitoring process does not constitute the ''bond'' of protection required for consumers.[683]

443. Consumer Advocates argue that the Final Rule erred in failing to explain what authority the Commission has to eliminate the statutory remedy of refunds of excessive charges, with interest, under section 205(e), and replace it with only disgorgement of excess profits or civil penalties whenever market manipulators are caught.[684] They contend that the Final Rule erred in relying on the Lockyer decision's erroneous finding that, because the market-based rate regime eliminates section 205(e) refunds for excessive charges paid, the Commission must create and substitute a new refund remedy to replace them.[685] Consumer Advocates assert that courts may not rewrite statutes or direct agencies to do so.[686] They argue that the Final Rule failed to explain (1) how *Lockyer's* curious ''two wrongs make a right'' approach is within the Ninth Circuit's authority, since only Congress can change a statute, (2) how *Lockyer's* new remedy helps consumers, who are supposed to receive refunds from excessive charges paid, not administrative penalties for reports that have been omitted; and (3) how the *Lockyer* decision's remedy replaces section 205(e)'s other eliminated consumer protections—prior review, suspension, and hearings with burden of proof on the seller.[687]

444. Consumer Advocates also contend that punishing manipulators, as the Final Rule proposed to do, is fine, but it does not make whole customers who have paid excessive rates set in part by those who manipulated the market.[688] They note that the Colorado Consumers Counsel section 206 proceeding is a case in which the Commission made the rates subject to refund under section 206 and subsequently found that all market-based rate tariffs which didn't have behavior rules attached were unjust and unreasonable and that the Commission ordered no refunds, but merely added behavior conditions to the market-based rate tariffs prospectively.[689]

445. Consumer Advocates also argue that the Final Rule erred in assuming that the Ninth Circuit and the D.C. Circuit are authorized to eliminate or affirm agency elimination of statutory consumer protections that Congress has enacted into law.[690] They state that agencies are bound, not only by the ultimate purposes Congress has selected, but by the means it has deemed appropriate and prescribed for the pursuit of those purposes.[691] They argue that in sections 205(d) and (e) of the FPA, Congress chose not only the goal of consumer protection from excessive rate increases, but also the means—advance rate filing and review, suspension, hearings with burden of proof on the seller, and immediate refund insurance—by which such protections would be afforded.[692] Consumer Advocates contend that the Final Rule ignored the clear mandates of the statute, and allows rate increases to be filed three months after they are charged, when the Commission has lost the power to initiate section 205(e) consumer protections.[693]

446. Consumer Advocates contend that the Final Rule's discussion of whether the Commission can simply eliminate any review of rate increases under the statutory protections of FPA section 205(e) appears to assume that the D.C. Circuit has authorized such elimination of section 205(e), and that the Court has the power to do so.[694] Consumer Advocates argue that the Supreme Court found that a wholesale seller's major duty under the FPA is to file its rates for review by the Commission and the public to determine whether hearings should be instigated under section 206, for initial rates, or section 205, for changes in rates.[695] They assert that the Final Rule ignored the lead cases on the FPA filing requirement, except to quote them for the proposition that the filing and hearing requirements are typically read *in pari materia*.[696] Consumer Advocates agree with that citation, however they argue that the purpose of the advance rate filings is for the Commission and the public to review rates before they are charged.[697]

447. Consumer Advocates argue that even if the Commission had authority to redefine rate increases as being mere rate ''reports,'' or EQRs, the Final Rule erred by failing to explain why the Commission would wish to eliminate all section 205(e) consumer protections by adopting this definition, and how such elimination satisfies the Commission's consumer protection responsibilities under the FPA.[698] They contend that the Commission's definition of rate increases as never occurring under the market-based rate regime, once a market-based rate tariff authorization is granted, allows the Commission to avoid prior review of all market-based rate increases and deprives consumers of all the protections provided by section 205(e).[699] Consumer Advocates note that the Final Rule's definitional elimination of rate ''increase'' protections is of particular importance to consumers in Maryland, Delaware, Illinois, Montana, Connecticut, and Ohio, among many other states, where retail ratepayers have been charged huge retail rate increases resulting solely from the pass-through of huge wholesale rate ''increases.''[700] They also contend that under the market-based rate regime as continued in the Final Rule, such wholesale increases have never been and never will be reviewed by the Commission under section 205(e) of the FPA.[701]

448. Consumer Advocates also argue that the Final Rule erred by failing to adequately distinguish the Supreme Court and Circuit court decisions outlawing attempts by other regulatory agencies to replace statutorily-mandated specific rates with a range of rates, when

[679] *Id.* (citing Order No. 697 at P 953–954).

[680] *Id.* at n.16.

[681] *Id.* at 17.

[682] *Id.* at 18.

[683] *Id.* (citing Order No. 697 at P 958–59).

[684] *Id.* at 32–33.

[685] *Id.* at 32.

[686] *Id.* (citing *MCI*; *Southwestern Bell*).

[687] *Id.* at 33–34.

[688] *Id.* at 33.

[689] *Id.* (citing 97 FERC ¶ 61,220 (2001); 105 FERC ¶ 61,218 (2003); 107 FERC ¶ 61,175 (2004)).

[690] *Id.* at 34.

[691] *Id.* at 36 (citing *MCI,* 512 U.S. at 231 n.4).

[692] *Id.*

[693] *Id.* at 35.

[694] *Id.* at 34 (citing Order No. 697 at P 948).

[695] *Id.* at 34–35 (citing *United Gas Pipe Line,* 350 U.S. at 341–42; *Sierra*).

[696] *Id.* at 35 (citing Order No. 697 at P 946, n.1070).

[697] *Id.*

[698] *Id.* at 36–37 (citing 774 F.2d 490, 493).

[699] *Id.* (citing *Atlantic Richfield; Electrical District; Lockyer,* 383 F.3d at 1017).

[700] *Id.* at 37.

[701] *Id.*

the market-based rate tariffs allow a range of rates so broad as to include any rate the parties agree to. Consumer Advocates contend that ''FERC's claim that the MBR's unlimited range of rates adequately substitutes for the 'specific' charges required under 205(d)'' is not sustainable under court precedent applying to the FPA and to other similar rate filing statutes.[702] They argue that the market-based rate, a statement that the rate will be anything the parties agree to, is even less specific than the ''legal and accounting principles,'' which the D.C. Circuit rejected in Electrical District[703] and state that it is instead, ''no more than an invitation to negotiate,'' an invitation that the same court rejected as a rate in Southwestern Bell.[704]

449. Consumer Advocates contend that in unlawfully replacing the requirement of section 205(d) for filing specific rate changes with a range of rates,[705] the Final Rule erred in relying on *Lockyer's* attempt to distinguish certain cases by claiming they were remanded by the Supreme Court because the agency had ''relied on market forces alone.''[706] According to Consumer Advocates, the *Lockyer* decision erred in failing to recognize that *Electrical District* and *Southwestern Bell* found unlawful the agencies' attempts to replace statutory requirements to file specific rates with ''ranges of rates'' for ''non-dominating'' entities.[707] Consumer Advocates also argue that rate ranges only apply to ''non-dominating'' wholesale sellers without market power, and that the courts have held that it is the Congress, not the agency, that determines what entities must continue to be regulated.[708]

450. Consumer Advocates contend that in *Regular Common Carrier Conference* v. *United States,* the importance of actual rates contained in tariffs was found to be ''utterly central'' to a rate filing statute.[709] They note that the Final Rule relied repeatedly on *LEPA,* which relies on *Elizabethtown Gas,* yet neither court decided the issue of whether the market-based rate filings or the overall market-based rate regime complies with the FPA.[710] Consumer Advocates also assert that the D.C. Circuit has repeatedly refused on procedural grounds to review the market-based rate regime's elimination of rate filings and its disregard for other section 205 mandates.[711] Consumer Advocates therefore conclude that the law of the D.C. Circuit on rate filings under section 206 of the FPA thus remains the decision in *Electrical District.*

451. Consumer Advocates argue that the Final Rule erred in relying chiefly on *Lockyer* for legal support for replacing advance rate increase filings with after-the-fact ''reporting requirements'' and that the Ninth Circuit panel, in turn, erroneously relied on Commission counsel's argument that the market-based rate tariffs plus the specific information on actual charges filed pursuant to the ''reporting requirements'' together comply with the FPA's requirement for filing specific rates.[712] Consumer Advocates state that if the reporting requirement filings contain a necessary component of the rate, that is, the component that renders the market-based rate specific enough to comply with the statute, then such reports must be filed 60 days in advance under section 205(d), otherwise, the rate reports must be filed as specifically directed by a section 205(d) order so as to allow for the full section 205(e) review, procedures and remedies.[713] They contend that the *United Gas Pipe Line/Sierra* cases and *City of Piqua* support this interpretation.[714] Consumer Advocates argue that under the Commission's ''reporting requirements'' scheme, only prospective section 206 review, hearings or refunds are possible and that under the market-based rate regime, rates may be increased exponentially, yet there are never any section 205(e) procedural protections or remedies available to consumers regarding whether actual rate levels fall within a ''zone of reasonableness.''[715]

452. NASUCA contends that under the Final Rule, market power review is to be eliminated altogether for many sellers in the Category 1 classification, with no specific review of those sellers' potential to exercise power.[716] NASUCA argues that there is no record in this case to support a generic finding that a seller with 499 MW capacity needs no market power review and a seller of 501 MW does.[717] NASUCA concludes that, in light of the Final Rule's reduced requirements for market power review, the *post hoc* reporting requirement is not sufficient to protect customers.[718]

Commission Determination

453. As we stated in the Final Rule, we disagree with Consumer Advocates' arguments that the Commission failed to show how market-based rates are just and reasonable and not unduly discriminatory or preferential. We reject Consumer Advocates' argument that the Final Rule failed to provide a standard for determining prohibited undue preference or discrimination under the Commission's market-based rate regime. The standard for judging undue discrimination remains what it always has been: disparate rates or service for similarly situated customers.[719] The Commission has held in prior cases, and the courts have upheld, that rates that are established in a market where a seller cannot exercise market power can be just, reasonable and not unduly discriminatory.[720]

454. The Final Rule does not violate the FPA's filing requirements. The FPA requires that every public utility file with the Commission ''schedules showing all rates and charges for any transmission or sale subject to the jurisdiction of the Commission,'' but it explicitly leaves the timing and form of those filings to the Commission's discretion.[721] Public utilities must file ''schedules showing all rates and charges'' under ''such rules and regulations as the Commission may prescribe,'' and ''within such time and form as the Commission may designate.''[722] Accordingly, ''so long as FERC has approved a tariff within the scope of its FPA authority, it has broad discretion to establish effective

[702] *Id.* at 27 (citing *Electrical District*; 16 U.S.C. 824e(a)).

[703] *Id.*

[704] *Id.* (quoting *Southwestern Bell,* 43 F.3d at 1521).

[705] *Id.* at 28.

[706] *Id.* (citing *Lockyer*, 353 F.3d at 1013; Order No. 697 at P 953).

[707] *Id.* at 29.

[708] *Id.* at 28–29 (citing *Maislin Indus. U.S.* v. *Primary Steel Inc.*, 497 U.S. 116 (1990) (*Maislin*); *MCI*; *Southwestern Bell*)

[709] *Id.* at 29 (citing *Regular Common Carrier Conference* v. *United States,* 793 F.2d 376, 379 (D.C. Cir. 1986) (*Regular Common Carrier*)).

[710] *Id.* (citing Order No. 697 at P 949–951). Consumer Advocates contend that *LEPA* and *Elizabethtown Gas* both explicitly state that they are not deciding the question of whether the market-based rate filing requirements or overall market-based rate regime comply with the FPA. *Id.* at 29–30 (citing *LEPA,* 141 F.3d at 366 n.2; *Elizabethtown Gas*, 10 F.3d at 871).

[711] *Id.* at 30 (citing *Elizabethtown Gas*; *LEPA*; *Power Company of America*, 245 F.3d 839 (D.C. Cir. 2001); *Colorado Office of Consumer Counsel* v. *FERC*, 490 F.3d 954 (D.C. Cir. 2007)).

[712] *Id.* at 25 (citing *Lockyer*, 383 F.3d 1015).

[713] *Id.*

[714] *Id.* at 25–26 (citing *City of Piqua* v. *FERC*, 610 F.2d 950 (1979), quoting *City of Kaukauna*, 458 F.2d 731 (1971)) (*City of Piqua*)).

[715] *Id.* at 26.

[716] NASUCA Rehearing Request at 18.

[717] *Id.*

[718] *Id.*

[719] *See* e.g., *Southwestern Electric Cooperative, Inc.* v. *FERC*, 347 F.3d 975, 981 (D.C. Cir. 2003).

[720] *See,* e.g., *Lockyer,* 383 F.3d at 1012–13; *Tejas Power Corp.* v. *FERC*, 908 F.2d 998, 1004 (D.C. Cir. 1990).

[721] 16 U.S.C. 824d(c).

[722] 16 U.S.C. 824d. The FPA does not define ''schedules,'' leaving that to the Commission's discretion as well. The Commission has defined ''rate schedule'' in its regulations at 18 CFR 35.2(b).

reporting requirements for administration of the tariff.'' [723] As the Commission explained in the Final Rule, if a seller is granted market-based rate authority, it must comply with post-approval reporting requirements, including the quarterly filing of transaction-specific data in EQRs, change in status filings for all sellers, and regularly-scheduled updated market power analyses for Category 2 sellers.[724] The Commission may, based on its review of EQR filings or daily market price information, investigate a specific utility or anomalous market circumstances to determine whether there has been any conduct in violation of RTO/ISO market rules or Commission orders or tariffs, or any prohibited market manipulation, and take steps to remedy any violations. These steps could include, among other things, disgorgement of profits and refunds to customers if a seller is found to have violated Commission orders, tariffs or rules, or a civil penalty.[725]

455. Additionally, in response to arguments that the Commission cannot or should not eliminate the triennial filing requirement for Category 1 sellers, as discussed above in the section on implementation, to the extent that any Category 1 sellers are located in a Commission-identified submarket, we will consider whether there is an indication that they have market power as we analyze the indicative screens submitted by other sellers. If any market power concerns arise with respect to any such Category 1 sellers, we may exercise our right to require the filing of an updated market power analysis and direct them at that time to submit one.

456. We also disagree with Consumer Advocates' argument that the market-based rate program eliminates the requirement in section 205(d) of the FPA that, absent waiver by the Commission, all rate increases be noticed by filing 60 days in advance, and the provision in section 205(e) which permits that, if warranted, rates be suspended for up to five months, set for hearing with the burden of proof on the seller, and made subject to refund pending the outcome of the hearing. Under the market-based rate program, a rate change is initiated when a seller applies for authorization of market-based rate pricing, not when it subsequently enters into negotiated rates as interpreted by Consumer Advocates. A seller must give the requisite 60 days' notice required by section 205(d) before it may charge any market-based rates. All applications are publicly noticed, entitling affected persons to intervene and challenge a seller's proposed market-based rates. At that time, there is an opportunity for a hearing, with the burden of proof on the seller to show that it lacks, or has adequately mitigated, market power, and for the imposition of a refund obligation.[726] The Commission has authority to suspend a request for market-based rates, subject to refund. Thus, contrary to Consumer Advocates' claim, the Commission's market-based rate program fully complies with both section 205(d) and section 205(e). Indeed, under Consumer Advocates' interpretation of the law, if taken to its logical conclusion, the Commission would be precluded not only from authorizing market-based rates but also from authorizing flexible cost-based rates, e.g., ''up to'' rates in which sellers are pre-authorized to sell up to a specified cost-based rate cap. Under their theory, there would have to be 60 days' notice of each rate charged under the cap (even though there was prior notice that sales would be up to the cap) so long as it represented a change from the previous amount charged. And presumably this requirement would apply even for day-ahead or monthly short-term sales for which it would be impossible to give 60 days' notice. We simply do not read the FPA section 205(d) and (e) or the parallel NGA section 4 provisions to hamstring the Commission in this way. Not only does section 205(c) provide flexibility regarding the timing and form in which rates shall be filed, but 205(d) allows the Commission to waive the 60 days' notice by order specifying the changes to be made and the time when they shall take effect and the manner in which they shall be filed and published. The Commission's authorization of market-based rates (and flexible cost-based rates) is consistent with the flexibility allowed in section 205, and the public has notice of the types of rates that may be charged and the manner in which they will be filed and published.

457. We reject arguments that the Commission has eliminated consumer protections under the FPA. Not only may the public intervene in section 205 market-based rate proceedings and file complaints under section 206 to eliminate market-based rate authorizations (with refund protection up to 15 months), but the Commission has in place a multi-part system for monitoring rates. If a seller is granted market-based rate authority, it must comply with post-approval reporting requirements, transaction-specific data in EQRs, change in status filings for all sellers, and regularly-scheduled updated market power analyses for Category 2 sellers.[727] The quarterly reports (EQRs) that sellers are required to file, include, for each individual purchase and sale, the names of the parties, a description of the service, the delivery point of the service, the price charged and quantity provided, the contract duration, and any other attribute of the product being purchased or sold that contributed to its market value.[728] That reporting requirement provides a means for the Commission and the public to spot pricing trends or discriminatory patterns that might indicate the exercise of market power.

458. The Ninth Circuit has recognized that ''FERC's system consists of a finding that the applicant lacks market power (or has taken sufficient steps to mitigate market power), coupled with a strict reporting requirement to ensure that the rate is 'just and reasonable' and that markets are not subject to manipulation.'' [729] The Ninth Circuit has explained that the reporting requirements are ''integral'' to the market-based rate tariff and that they, together with the Commission's initial approval of market-based rate authority, comply with the FPA's requirements.[730] Through the EQRs, the Commission has enhanced and updated the post-

[723] *Lockyer,* 383 F.3d at 1013.

[724] Order No. 697 at P 962. The Commission explained in the NOPR that preceded Order No. 2001 that it needed to make changes to keep abreast of developments in the industry, and therefore implemented the revised filing requirements in Order No. 2001. *Id.* P 965–966 (citing *Revised Public Utility Filing Requirements, Notice of Proposed Rulemaking*, FERC Stats. & Regs., Proposed Regulations 1999–2003, ¶ 32,554, at 34,062 (2001); *Revised Public Utility Filing Requirements*, Order No. 2001, FERC Stats. & Regs. ¶ 31,127, at P 31 (Order No. 2001), *reh'g denied*, Order No. 2001–A, 100 FERC ¶ 61,074, *reh'g denied*, Order No. 2001–B, 100 FERC ¶ 61,342, *order directing filing*, Order No. 2001–C, 101 FERC ¶ 61,314 (2002), *order directing filing*, Order No. 2001–D, 102 FERC ¶ 61,334 (2003)). The Commission has also issued Order No. 670, which adopted a new rule prohibiting the employment of manipulative or deceptive devices or contrivances in wholesale energy and natural gas markets. *Prohibition of Energy Market Manipulation*, Order No. 670, 71 FR 4244 (Jan. 26, 2006), FERC Stats. & Regs. ¶ 31,202 (2006), *reh'g denied*, 114 FERC ¶ 61,300 (2006).

[725] Order No. 697 at P 964. The Commission issued an Enforcement Policy Statement to provide guidance to the industry on how the Commission intends to determine remedies for violations, including applying its new and expanded civil penalty authority. *Enforcement of Statutes, Orders, Rules, and Regulations,* 113 FERC ¶ 61,068 (2005).

[726] *Id.*; *see also* 18 CFR Part 35 (filing requirements and procedures).

[727] *Id.* (citing *Lockyer*, 383 F.3d at 1016).

[728] *Id.* P 855. *See also* Order No. 2001, FERC Stats. & Regs. ¶ 31,127. Required data sets for contractual and transaction information are described in Attachments B and C of Order No. 2001.

[729] *Lockyer*, 383 F.3d at 1013.

[730] *Id.* at 1015.

transaction quarterly reporting filing requirements that were in place during the time period at issue in *Lockyer*.[731]

459. We disagree with the Consumer Advocates' and NASUCA's argument that the Final Rule erred in relying on *Lockyer* for legal support. The Final Rule correctly relied on *Lockyer* because in *Lockyer*, the Ninth Circuit cited with approval the Commission's dual requirement of an *ex ante* finding of the absence of market power and sufficient post-approval reporting requirements and found that the Commission did not rely on market forces alone in approving market-based rate tariffs.[732] Further, the market-based rate requirements and oversight adopted in the Final Rule are more rigorous than those reviewed by the *Lockyer* court.[733] We find Consumer Advocates' and NASUCA's argument that in *Lockyer* the Ninth Circuit erroneously relied on Commission counsel's argument that the market-based rate tariffs plus the specific information on actual charges filed pursuant to the reporting requirements together comply with the FPA's filing requirements to be without merit. *Lockyer* has not been reversed, and in fact, was followed by the Ninth Circuit in *Snohomish*.[734]

460. Consumer Advocates misapply *United Gas Pipe Line, Sierra* and *City of Piqua* in arguing that these cases require that specific sale prices must be filed *ex ante* under FPA section 205(d). In concluding that the NGA does not empower natural gas companies unilaterally to change their contracts in *United Gas Pipe Line*, the Supreme Court interpreted provisions of the NGA that parallel the FPA, and it stated that section 4(d) of the NGA says only that ''a change in the filed rate *cannot* be made without proper notice to the Commission.'' [735] That same day the Supreme Court held in *Sierra* that the FPA does not authorize unilateral contract changes [736] and determined that the Federal Power Commission could not declare a rate set by a contract to be ''unreasonable solely because it yields less than a fair return on the next invested capital.'' [737] In *City of Piqua*, the D.C. Circuit explained that the primary purpose of section 205(d) is to notify the Commission of changes in rates and schedules between parties to a contract, stating ''[a] change in rates cannot take place without first filing notice with the Commission.'' [738]

461. Consumer Advocates' argument that *United Gas Pipe Line, Sierra* and *City of Piqua* require that rate reports must be filed *ex ante* under FPA section 205(d) overlooks the fact that, under the market-based rate program, the rate change is initiated when a seller applies for authorization of market-based rate pricing. As we explained, all applications are publicly noticed and affected persons are entitled to challenge a seller's claims. There is an opportunity for a hearing at that time, with the burden of proof on the seller to show that it lacks, or has adequately mitigated, market power, and for the imposition of a refund obligation.[739] That investigation fully satisfies the requirements of FPA section 205(d) and (e).

462. With regard to Consumer Advocates' argument that the Final Rule erred by failing to adequately distinguish certain Supreme Court and Circuit case decisions, we find that Consumer Advocates misinterpret *Electrical District, Southwestern Bell, Maislin, MCI* and *Regular Common Carrier* in relying on these cases as support for their argument that the Commission's market-based rate regime is unlawful. *Electrical District* addressed the issue of whether to make a rate increase effective as of the date of its order directing a compliance filing, rather than upon the date of acceptance of the compliance filing and resolved a ''disagreement over what it means to 'fix' a rate within the meaning of [section 206(a)] 16 U.S.C. 824e(a)''—not section 205(c).[740] The D.C. Circuit rejected the Commission's ''policy of making rates effective as of the date of an order [under section 206] setting forth no more than the basic principles pursuant to which the new rates are to be calculated.'' [741] *Electrical District* holds only that the Commission cannot, in a proceeding under section 206, ''announce some formula and *later* reveal that formula was to govern from the date of announcement.'' [742] It says nothing about whether the Commission can establish rules under sections 205(c) and (d) that permit the filing and approval of market-based rate tariffs.

463. In *Southwestern Bell*, the FCC ''adopt[ed] a policy of permitting nondominant common carriers to file a range of rates as opposed to fixed rates showing a schedule of charges.'' [743] The court held that the FCC policy violated 47 U.S.C. section 203(a), which requires that every common carrier file ''schedules showing all charges.'' [744] That statute requires a specific list of discernible rates, rather than a filing of a range of possible rates.[745] The quarterly reports required under the Final Rule require each seller to list the terms of each transaction individually. The transaction-specific data required in the Commission's quarterly reports do not constitute a range of rates similar to that rejected in *Southwestern Bell*.

464. In *Regular Common Carrier*, the Interstate Commerce Commission (ICC) approved a tariff provision under which freight forwarders could provide services to shippers at unpublished rates determined by averaging prior charges to those shippers.[746] The court found that that provision violated 49 U.S.C. section 10761(a) (1982), which required that rates be ''contained in a tariff,'' because the agreed-upon average rates would never be published nor filed with the Commission.[747] The court noted that section 10761(a) expressly prohibited the charging of any rate different from the tariffed rate.[748] By contrast, FPA section 205(c) permits sellers to set rates either by tariff or by contract, and the Commission's market-based rate program requires quarterly filings providing details of all transactions.

465. *Maislin* involved an ICC policy that allowed carriers to charge privately negotiated contract rates that differed from the filed tariff rate, were never disclosed or reviewed by the ICC, and were not subject to challenge for discrimination.[749] The Supreme Court found that the policy violated the filed-rate doctrine.[750] Under the Final Rule, in contrast, market-based sales are made in accordance with a market-based rate umbrella tariff, approved only after the Commission determines, in a publicly-noticed proceeding with opportunity for interested parties to protest, that a seller lacks market power. Further, the Commission's system requires quarterly filing of the actual rates charged for individual transactions, allowing both the Commission and the public to view all rates all rates charged. After market-based rate authority is granted, affected persons can file complaints, or the

[731] Order No. 697 at n.1105.

[732] *Lockyer*, 383 F.3d at 1013.

[733] *See* Order No. 697 at P 953.

[734] *Snohomish*, 471 F.3d at 1080–81.

[735] *United Gas Pipe Line*, 350 U.S. at 339 (emphasis in original).

[736] *Sierra*, 350 U.S. at 353.

[737] *Id.* at 355.

[738] *City of Piqua*, 610 F.2d at 953.

[739] Order No. 697 at P 962; *see also* 18 CFR Part 35 (filing requirements and procedures).

[740] 774 F.2d at 492.

[741] *Id.* at 493.

[742] *Transwestern Pipeline Co.* v. *FERC*, 897 F.2d 570, 578 (D.C. Cir. 1990) (emphasis added).

[743] 43 F.3d at 1517.

[744] *Id.*

[745] *Id.* at 1521.

[746] *Regular Common Carrier*, 793 F.2d at 377–78.

[747] *Id.* at 380.

[748] *See id.* at 379.

[749] 497 U.S. 116, 132–33 (1990).

[750] *Id.* at 127.

Commission can institute its own proceeding, to challenge market-based rates on the basis that the seller has gained the ability to exercise market power since the time the market-based rates were granted or that the market-based rates otherwise are unjust, unreasonable, or unduly discriminatory or preferential or to question whether a seller has market power.

466. Consumer Advocates' reliance on *MCI* is similarly misplaced. *MCI* rejected an FCC policy that relieved *all* non-dominant carriers of *any* requirement to file any of their rates with the agency. The Supreme Court found that such wholesale detariffing for nondominant carriers effectively removed all rate regulation where the FCC found competition to exist.[751] By contrast, the market-based rate program implemented in Order No. 697 requires every seller with market-based rate authority to have on file an umbrella market-based rate tariff and to file quarterly reports detailing the specific rates charged for each sale. No detariffing occurs in these circumstances. As the *MCI* court held, it would not violate the filed-rate doctrine for the FCC to ''modify the form, contents, and location of required filings, and [to] defer filing or perhaps even waive it altogether in limited circumstances.'' [752]

467. Consumer Advocates' argument that the Commission relied repeatedly on *Elizabethtown Gas* and *LEPA*, yet neither court decided the issue whether the market-based rate filings or the overall market-based rate regime complies with the FPA, misses the point that the Commission cited these cases in providing an overview of the cases relied on in the most recent court cases affirming the Commission's market-based rate authority under the FPA.[753] Further, the Commission properly cited *Elizabethtown Gas* for the proposition that the use of market-based rate tariffs was first approved by the courts as to sellers of natural gas,[754] and properly cited *LEPA* for the proposition that use of market-based rate tariffs was first approved by the courts as to wholesale sellers of electricity.[755] In any event, as the Commission explained in the Final Rule, the more recent precedent in *Lockyer* and *Snohomish* has upheld the Commission's dual requirement of an *ex ante* finding of the absence of market-power and sufficient post-approval reporting requirements as complying with the requirements of the FPA.[756]

468. With respect to Consumer Advocates' concern about long-term affiliate sales contracts not being filed, the Commission pointed out in the Final Rule that since 2002, its regulations have provided that long-term market-based rate power sales service agreements, with affiliates or otherwise, are not to be filed with the Commission.[757] However, the affiliate restrictions require that no wholesale sales of electric energy may be made between a franchised public utility with captive customers and a market-regulated power sales affiliate without first receiving Commission authorization (separate from the general market-based rate authorization at issue in this docket) for the transaction under section 205 of the FPA. As a result, a franchised public utility with captive customers cannot enter into a long-term contract with an affiliate without the seller under the contract (whether the franchised public utility or the affiliate) first receiving Commission authorization to engage in the affiliate sale.[758] To the extent that a particular affiliate relationship presents issues of concern, it will be considered in the context of our determination whether to authorize any affiliate sales. Further, our market-based rate program incorporates numerous protections against excessive rates, regardless of the identities of the parties to a transaction. Finally, although long-term contracts generally are not filed at the Commission, all relevant contract information is contained in the EQRs and thus the same information is available to the public and the Commission. Thus, we will continue to direct sellers not to file long-term market-based rate sales contracts, unless otherwise permitted by Commission rule or order.[759]

469. For the reasons stated in the section of this order addressing Implementation Process, we reject NASUCA's argument that there is no record to support the finding that a seller with 499 MW capacity needs no triennial power review and a seller of 501 MW does need market power review.[760]

b. Whether the Final Rule Shifts the Burden of Proof Under Section 205 of the FPA

Final Rule

470. In the Final Rule, the Commission noted that it had previously addressed and rejected the argument that the legal presumptions that follow from the Commission's market power screens would unduly shift the burden of demonstrating the existence of market power to intervenors. On rehearing of the April 14 Order, the Commission explained that nothing in that order shifts the burden of proof that section 205 imposes on the filing utility. Passing both screens or failing one merely establishes a rebuttable presumption. To challenge a seller who passes both screens, the intervenor need not conclusively prove that the seller possesses market power. Rather, the intervenor need only meet a burden of going forward with evidence that rebuts the results of the screens. At that point, the burden of going forward would revert back to the seller to prove that it lacks market power. Thus, the burden of proof under section 205 ultimately belongs to the seller.[761]

Requests for Rehearing

471. Consumer Advocates argue that the Final Rule unlawfully shifts the statutory burden of proof from the electricity seller under section 205(e), to justify increased rates, to the electricity

[751] 512 U.S. 218, 231–32 (1994).

[752] *Id.* at 234.

[753] Order No. 697 at P 944; *see also, id.* at 945–953; *Lockyer*, 383 F.3d at 1011–1014.

[754] *Elizabethtown Gas*, 10 F.3d at 869; *see also* Order No. 697 at P 948.

[755] *LEPA*, 141 F.3d at 365, 370; *see also* Order No. 697 at P 951. Consumer Advocates' reliance on *Power Company of America*, 245 F.3d 839 (D.C. Cir. 2001) and *Colorado Office of Consumer Counsel* v. *FERC*, 490 F.3d 954 (D.C. Cir. 2007) does not support their argument that the Final Rule violates the FPA's filing requirement. In *Power Company of America* the court declined to address Power Company of America's (PCA) argument that umbrella agreements of power marketers were required to be on file because this argument was not raised in PCA's opening brief. *See Power Company of America*, 245 F.3d at 845. In *Colorado Office of Consumer Counsel*, the court denied the Colorado Office of Consumer Counsel's petition for review of a Commission order approving market behavior rules because FPA section 206's plain language does not require the Commission, having found only one aspect of the market-based rate tariffs to be unjust and unreasonable, to revisit all elements of its market-based rate tariffs. Thus, the D.C. Circuit did not review the market-based rate regime's filing requirements in these two cases because the filing requirement issue was not before the court. Consumer Advocates' argument in this regard fails because it disregards the precedent upholding the Commission's dual requirement of an *ex ante* finding of the absence of market power and sufficient post-approval reporting requirements. *Lockyer*, 383 F.3d 1006; *Snohomish*, 471 F.3d 1053.

[756] *Lockyer*, 383 F.3d 1006; *Snohomish*, 471 F.3d 1053. Consumer Advocates also argue that the Final Rule ignored the lead cases on the FPA filing requirement, except to quote them for the proposition that the filing and hearing requirements of the NGA and FPA are typically read *in pari materia*. Consumer Advocates Rehearing Request at 34–35 (citing *United Gas Pipe Line; Sierra*; Order No. 697 at P 946, n.1070). We address Consumer Advocates' argument in this regard at *supra* P 412, 461–64.

[757] Order No. 697 at P 969 (citing 18 CFR 35.1(g)).

[758] *Id.* P 969–970.

[759] *Id.* P 970.

[760] *See supra* P 344–47.

[761] Order No. 697 at P 968. The Commission also concluded that it will continue to direct sellers not to file long-term market-based rate sales contracts, unless otherwise permitted by Commission rule or order. *Id.* P 969–70.

consumer under section 206(a), to prove both that such increased rates are excessive and to justify different rates.[762] They also contend that the Final Rule claims to justify this shift of burden of proof by stating that the burden is still on the seller to show it has no market power, even though sellers are no longer required to justify rate increases.[763] Consumer Advocates assert that FPA section 205, under which market-based rate tariff authorizations are approved, does not mention '''market power,''' but requires that sellers have the burden of justifying proposed rate increases.[764] Consumer Advocates state that the results on consumers can be seen in the Commission's recent denial of a complaint by the Connecticut Attorney General because Connecticut failed to carry its burden of proof under section 206(a).[765]

472. Southern contends that the Final Rule violates the requirement in FPA section 206 that the Commission bear the burden of proof in section 206 proceedings and that the Commission's determinations be based on substantial evidence.[766] According to Southern, this shifting of the burden of proof occurs through the use of indicative screens, which Southern contends are inherently flawed. Southern states that once a screen failure occurs and a presumption of market power arises, sellers only have two options: Either accept a determination that it has market power and adopt cost-based mitigation measures, or provide the Commission with a DPT analysis.[767] Southern concludes that by applying the indicative screens codified in the Final Rule the Commission will effectively shift to sellers the evidentiary burden in a section 206 proceeding.[768]

473. Southern also argues that the screens are inherently flawed in their ability to definitively assess market power when none is actually present, noting that the Final Rule ''acknowledges that the screens are 'conservative' in nature and will undoubtedly result in 'false positives' indicating market power.'' [769] Southern argues that because of their conservative nature and propensity to result in false positives, such screens cannot properly provide a basis for shifting the burden of proof to sellers, and are incapable of providing substantial evidence of market power.

474. Southern contends that by shifting the section 206 burden of proof to sellers, the Final Rule shifted to sellers the burden of rebutting the presumption of generation market power. Southern states that the unlawfulness of shifting this burden is exacerbated by the restriction placed on the type of evidence that sellers may present to rebut the market power presumption. Specifically, Southern asserts that the Final Rule only allows sellers to submit (1) historical sales and transmission data and (2) an analysis using the DPT (using only historical data) to demonstrate that they do not have market power, and that these limitations on sellers' ability to rebut the false presumption of generation market power are inconsistent with the FPA since they arise in the context of a section 206 proceeding, in which the Commission is required to bear the burden of proof.[770]

475. Southern argues that the Commission should reconsider its determination in the Final Rule that a failure of an indicative screen results in a presumption of market power, and should instead determine that the indicative screens are only intended to identify sellers that appear to raise no horizontal market power concerns and thus can be considered for market-based rate authority without the necessity of further analysis.[771] In other words, passing the screens should raise a favorable presumption that a seller does not have market power, and a seller would never be ''presumed'' to have generation market power.[772]

Commission Determination

476. With regard to Consumer Advocates' assertion that the Final Rule shifts the burden of proof from the electricity seller under section 205(e) to the electricity consumer under section 206(a), we reiterate that the Commission has not shifted the burden of proof that section 205 imposes on the filing utility. A utility seeking to make sales at market-based rates has the burden of proof under section 205 to show that it does not have, or has adequately mitigated, market power. Because passing both indicative horizontal market power screens establishes a rebuttable presumption that the seller lacks market power, the burden is then on the intervenor to provide evidence to rebut the presumption of no market power.[773] To challenge a seller who passes both screens, the intervenor need not conclusively prove that the seller possesses market power. Rather, the intervenor need only meet a burden of going forward with evidence that rebuts the results of the screens. At that point, the burden of going forward would revert back to the seller to prove it lacks market power. Ultimately, however, the burden of proof under section 205 belongs to the seller.[774]

477. We reject Consumer Advocates' argument that the Final Rule shifts the FPA section 205 burden of proof to justify rate increases from the electricity seller to the electricity consumer under section 206(a) to prove both that such increased rates are excessive and to justify different rates, and that this can be seen in the Commission's denial of the Connecticut Attorney General's complaint in *Blumenthal* because Connecticut failed to carry its burden of proof under FPA section 206(a). *Blumenthal* was an FPA section 206 complaint proceeding in which the complainants challenged ISO–NE's current Market Rule 1 as unjust and unreasonable with regard to the compensation of generation facilities needed for reliability in Connecticut. Because that case was brought under section 206 of the FPA, the burden properly was on complainants to establish that the current provisions of Market Rule 1 are unjust and unreasonable. However, that case is distinguishable from the circumstance where a seller seeks authorization to make sales at market-based rates. As

[762] Consumer Advocates Rehearing Request at 31–32.

[763] *Id.* at 32 (citing *MCI; Southwestern Bell*).

[764] *Id.*

[765] *Id.* (citing *Blumenthal*, 117 FERC ¶ 61,038 at P 57).

[766] Southern Rehearing Request at 7–8 (citing 16 U.S.C. 824e(a); *Sierra*, 350 U.S. at 353; *Public Service Commission of New York* v. *FERC*, 642 F.2d 1335, 1345 (D.C. Cir. 1980); *Public Service Co. of New Mexico*, 115 FERC ¶ 61,090, at P 33 (2006)).

[767] *Id.* at 7 (citing Order No. 697 at P 63).

[768] *Id.* at 8.

[769] *Id.* at 8 (citing Order No. 697 at P 62, 71, 74, 89).

[770] *Id.* at 10–11 (citing Order No. 697 at P 33, 75).

[771] *Id.* at 11.

[772] *Id.*

[773] *See* Order No. 697 at P 968 (citing July 8 Order, 108 FERC ¶ 61,026, at P 29).

[774] *See July 8 Order at* P 29 (stating that passing both screens or failing one merely establishes a rebuttable presumption, and explaining that in the case of an intervenor in a section 205 proceeding that seeks to prove that the applicant possesses market power, ''the intervenor need only meet a 'burden of going forward' with evidence that rebuts the results of the screens. At that point, the burden of going forward would revert back to the applicant to prove that it lacks market power.'') (citing *Pennzoil Co.* v. *FERC*, 645 F.2d 360, 392 (5th Cir. 1981), *cert. denied*, 454 U.S. 1142 (1982); *accord Transcontinental Gas Pipe Line Corp.*, Opinion No. 135, 17 FERC ¶ 61,232, at 61,450 (1981) (''The presumption * * * is the same as that which arises from a prima facie case: it imposes on the party against whom it is directed the burden of going forward with substantial evidence to rebut or meet the presumption, but does not shift the burden of persuasion.''); *Generic Determination of Rate of Return on Common Equity for Electric Utilities*, Order No. 389–A, 29 FERC ¶ 61,223 (1984) (concluding that the rebuttable presumption that a rate of return based on a benchmark is just and reasonable does not shift the ultimate burden of proof imposed by the FPA).

discussed above, in the case of a seller seeking market-based rate authority from the Commission under section 205, the burden of proof is on the seller to prove that it lacks market power. However, in a section 206 complaint proceeding, the burden is on the complainant to show that the current rates are unjust and unreasonable. Thus, State AGs and Advocates' argument that *Blumenthal* supports their assertion that the Final Rule shifts the FPA section 205 burden of proof to justify rate increases from the electricity seller to the electricity consumer under section 206(a) is without merit.

478. For the reasons stated in the section of this order addressing horizontal market power, we reject Southern's argument that the burden of proof in a section 206 proceeding is shifted to entities that fail one of the indicative screens.

c. Whether Elimination of the Requirement To File Market-Based Rate Contracts in a Prior Rulemaking Proceeding May Be Challenged in the Instant Rulemaking

Final Rule

479. The Final Rule concluded that the multiple layers of filing and reporting requirements incorporated into the market-based rate program, the Commission's enhanced market oversight and enforcement functions, and the ability of the public to file section 206 complaints meet the filing requirements of the FPA and provide adequate protection from excessive rates. In reaching this determination, the Commission noted that the decision to eliminate the filing of market-based rate contracts was made almost five years ago in a generic rulemaking proceeding that was open to participation by all interested parties.[775] The Commission explained that commenters' failure to raise this concern in that proceeding precludes them from attacking the Commission's well-settled practice in the instant rulemaking.[776]

Requests for Rehearing

480. Consumer Advocates argue that the Final Rule erred in asserting that challengers to the Commission's market-based rate regime are precluded by the passage of time and by earlier rulemaking proceedings from now raising their challenges to the Commission's authority to issue its market-based rate regulations, including their arguments that the regulations are contrary to the filing and other requirements of FPA sections 205 and 206.[777] Consumer Advocates state that the Final Rule noted that the failure of commenters to object to an earlier rulemaking that eliminated the filing of market-based rate contracts almost five years ago now precludes them from asserting that the Commission's actions in the instant rulemaking violate the FPA's filing requirements.[778] Consumer Advocates contend that the Commission's view that commenters are precluded from attacking the rules promulgated in this proceeding is incorrect insofar as the D.C. Circuit has made clear that where an agency itself reopens an issue by initiating a new rulemaking procedure, participants in the rulemaking are not barred from challenging the new rule by their failure to challenge prior agency actions.[779] Consumer Advocates argue that members of the public may raise issues notwithstanding failure to participate in an earlier rulemaking '' 'when the agency in question by some new promulgation creates the opportunity for renewed comment and objection.' '' [780]

481. Consumer Advocates argue that where the challenge is that the agency lacks statutory authority to take an action, a commenter's earlier failure to challenge another regulation cannot bar consideration of the agency's statutory authority for the action it now proposes to take. They conclude that where the petitioner challenges the substantive validity of a rule, failure to exercise a prior opportunity to challenge the regulation ordinarily will not preclude review.[781] Consumer Advocates assert that the D.C. Circuit has held that the rule barring collateral attacks on regulations does not apply to claims that ''an agency lacked the statutory authority to adopt the rule.''[782]

482. Consumer Advocates also state that they filed a petition for review in the D.C. Circuit over three years ago raising these issues in the context of a challenge to the Commission's actions in its Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations, an FPA section 206 proceeding in which Consumer Advocates participated and presented their challenges to the market-based rate regime to the Commission in great detail.[783] They state that the Commission has argued in the D.C. Circuit, successfully so far, that Consumer Advocates' challenge to the market-based rate regime was not properly presented in that matter and should be addressed in some other appropriate proceeding.[784] Consumer Advocates conclude that the Commission may not now assert that Consumer Advocates have slept on their rights and cannot present their arguments in a rulemaking that raises the issue of the lawfulness of the Commission's market-based rate regime.[785]

Commission Determination

483. Consumer Advocates' attack on a sentence in a footnote stating that ''Commenters' failure to raise this concern [regarding the filing of market-based rate contracts] in that proceeding precludes them from attacking the Commission's well-settled practice here'' [786] makes more of this footnote than it was intended to convey. This sentence was intended to clarify that the Commission had previously determined to eliminate the filing of market-based rate contracts in Order No. 2001,[787] and to clarify that the Commission is not reconsidering this issue as part of this rulemaking proceeding. This sentence does not stand for the broad proposition, as suggested by Consumer Advocates, that ''challengers to the Commission's market-based rate regime are precluded by the passage of time and by earlier rulemaking proceedings from now raising their challenges to the Commission's authority to issue its market-based rate regulations, including their arguments that the regulations are contrary to the filing and other requirements of FPA sections 205 and 206.'' Indeed, in the Final Rule, the Commission fully responded to the arguments raised by Consumer Advocates in their NOPR comments, in which they challenged the Commission's authority to issue its market-based rate regulations and argued, among other things, that the regulations are contrary to the filing and other requirements of FPA sections 205

[775] Order No. 697 at P 967, n.1112.

[776] *Id.*

[777] Consumer Advocates Rehearing Request at 37–38.

[778] *Id.* at 38 (citing Order No. 697 at P 967, n.1112).

[779] *Id.* (citing *Montana* v. *Clark,* 749 F.2d 740, 744 (D.C. Cir. 1984), *cert. denied,* 474 U.S. 919 (1985)).

[780] *Id.* at 38 (quoting *Ohio* v. *EPA,* 838 F.2d 1325, 1328 (D.C. Cir. 1988); *accord Ass'n of Am. R.Rs.* v. *ICC,* 846 F.2d 1465, 1473 (D.C. Cir. 1988); *Public Citizen* v. *NRC,* 901 F.2d 147, 150 (D.C. Cir. 1990), *cert. denied,* 498 U.S. 992 (1990)).

[781] *Id.* at 39 (citing *Montana* v. *Clark,* 749 F.2d at 744 n.8).

[782] *Id.* (quoting *Indep. Community Bankers of Am.* v. *Bd. of Governors of Fed. Reserve Sys.,* 195 F.3d 28, 34 (D.C. Cir. 1999); *NRDC* v. *NRC,* 666 F.2d 595, 602 (D.C. Cir. 1981)).

[783] *Id.* at 40.

[784] *Id.* (citing *Colorado Office of Consumer Counsel* v. *FERC,* 490 F.3d 954 (D.C. Cir. 2007)).

[785] *Id.*

[786] Order No. 697 at n.1112.

[787] Order No. 2001, FERC Stats. & Regs. ¶ 31,127 at P 31.

and 206.[788] Moreover, the Commission is responding to their arguments on rehearing in the instant order. Thus, the Commission has thoroughly addressed Consumer Advocates' arguments regarding the instant market-based rate rulemaking proceeding in both the Final Rule and in this order.

d. Whether the Commission Should Clarify That Sellers With Market Power Must File Their Actual Rates and Contracts Before the Charges Are Implemented

Final Rule

484. The Final Rule concluded that, with regard to NASUCA's assertion that the rule would allow mitigated sellers with cost-based rates to declare their own rates without filing them, all mitigation proposals, whether based on the default cost-based rates or some other cost-based rates, must be filed with the Commission for review. The Commission stated that, as explained in the Mitigation section of the Final Rule, any such filings are noticed, and interested parties are given an opportunity to intervene, comment on, or protest the submittal.[789]

Requests for Rehearing

485. NASUCA raises a similar argument on rehearing, claiming that sellers *with* market power should not be allowed to determine and change their rates without complying with FPA filing requirements.[790] NASUCA states that sellers with market power, have, until now, been required to file cost-based rates, and argues that the Final Rule allows sellers with market power to dispense with the filing of contracts and changes in rates for sales of less than one year under the default mitigation rates.[791] NASUCA states that only contracts for sales greater than one year would be filed under section 205.[792] According to NASUCA, a consequence is that there is no possibility of public notice, protest, Commission review prior to imposition of unreasonable new charges, and no opportunity for refund of unreasonable rates charged by sellers with market power for sales of up to one year's duration.[793]

486. NASUCA contends that allowing sellers with market power to dispense with the filing of contracts and changes in rates for sales of less than one year under the default mitigation rates, and "to set rates at will between marginal cost and embedded cost may not be reasonable and could allow discrimination." [794] NASUCA argues that even though looked at separately, the incremental cost rate base and the embedded cost rate could be within the zone of reasonableness, giving the utility the option to pick its rates and its customers in bilateral transactions, which could give the utility with wholesale market power the opportunity to extend it into retail markets, favoring its retail affiliate.[795] NASUCA notes that in *FPC* v. *Conway Corp.,* the Supreme Court held that a utility could not set low retail rates to attract retail industrial customers from other utilities and set wholesale rates at prices higher than the retail rate so that its wholesale competitors could not compete in the retail market. Thus, NASUCA concludes that the Commission should not allow this potentially discriminatory and predatory conduct in the name of granting " 'flexibility' " to utilities.[796]

487. NASUCA also argues that allowing sellers with market power to make sales for less than one year without filing them is a subdelegation to private parties of basic duties conferred upon the Commission by Congress.[797] In support of this point, NASUCA states that in *ISO New England, Inc.,* Chairman Kelliher disagreed with the Commission's decision to deny rehearing of an earlier order that accepted for filing three mitigation agreements and granted waiver of the 60 day prior notice requirement.[798] NASUCA concludes that the Final Rule has the same defect identified by Chairman Kelliher: Rates of sellers with market power, when they involve sales for less than one year, are allowed to take effect without observing prior filing requirements, with the Commission relying on private parties to negotiate and charge reasonable rates.[799] NASUCA asserts that there is no provision in the FPA granting the Commission the power to direct utilities not to file their rates for sales of less than one year, and no evidence that such rates are reasonable.[800] NASUCA states that the D.C. Circuit rejected rates that had been charged by utility negotiation at marginal cost plus 10 percent without being timely filed for possible review and revision by the Commission for lack of evidence, and argues that the same flaw applies here to the generic rate ranges approved for sellers with market power. According to NASUCA, there is no evidence that such rates are reasonable.[801]

488. NASUCA states the Final Rule responded to NASUCA's concerns by saying that rate " 'proposals' " of mitigated sellers would be filed, but the Final Rule does not say rates, rate schedules, and contracts will be filed.[802] NASUCA contends that the Final Rule adopted a rule which clearly states that only new contracts of a duration longer than one year are to be filed under section 205. NASUCA argues that in analogous circumstances where actual changes in rates and charges had not been filed, the D.C. Circuit stated that " 'making rates effective as of the date of an order setting forth no more than the basic principles pursuant to which the new rates are to be calculated would make unforeseeable liabilities a regular consequence of rate adjustments.' " [803] NASUCA therefore requests that the Commission clarify that sellers with market power must file not only " 'proposals,' " but also schedules containing their actual rates and contracts, before the charges are implemented, in accordance with FPA section 205.[804]

Commission Determination

489. With regard to NASUCA's arguments concerning filing requirements for sellers with market power, to the extent a seller proposes a cost-based rate that is based on a formula, it is our practice to require that the rate formula used be provided for Commission review and such formula included in the cost-based rate tariff, including formulas used in calculating incremental cost for purposes of the Commission's default cost-based rates.[805] As the Commission explained in the Final Rule, all mitigation proposals by a seller found, or presumed, to have market power must be filed with the Commission for review. These filings are noticed and interested parties are provided the opportunity to intervene, comment or

[788] Order No. 697 at P 943–955, 959–968.

[789] *Id.* P 971.

[790] NASUCA Rehearing Request at 8.

[791] *Id.* at 9 (citing Order No. 697 at 18 CFR 35.38).

[792] Although NASUCA refers to contracts for "sales greater than one year," the Commission's default rates for long-term sales cover sales of "one year or more." Order No. 697 at P 659.

[793] NASUCA Rehearing Request at 9.

[794] *Id.*

[795] *Id.*

[796] *Id.* at 10 (citing 426 U.S. 271 (1976)).

[797] *Id.* (citing *U.S. Telecom Ass'n* v. *FCC,* 359 F.3d 554, 567–78 (D.C. Cir. 2004)).

[798] *Id.* (citing *ISO New England, Inc.,* 112 FERC ¶ 61,057 (2005), *reversed on other grounds, NSTAR Electric & Gas Corp.* v. *FERC,* 481 F.3d 794 (D.C. Cir. 2007) (*NSTAR*)).

[799] *Id.* at 11.

[800] *Id.* (citing *MCI,* 512 U.S. at 229–30; *American Telephone & Telegraph Co.* v. *Central Office Telephone Inc.,* 524 U.S. 214 (1998)).

[801] *Id.* (citing *NSTAR,* 481 F.3d 794).

[802] *Id.* at 12 (citing Order No. 697 at section 35.38).

[803] *Id.* (quoting *Electrical District,* 774 F.2d at 492–93).

[804] *Id.*

[805] Order No. 697 at P 630.

protest the submittal.[806] In response to NASUCA's concern regarding the Commission's use of the word ''proposals,'' we clarify that by ''mitigation proposals'' we were referring to cost-based rate tariffs that incorporate the seller's proposal for mitigation. As the Commission stated in the April 14 Order, where a seller proposes to adopt the default cost-based rates (or where it proposes other cost-based rates), it must provide cost support for such rates. The Commission will examine the proposed rates on a case-by-case basis.[807] With regard to sales of one week or less, where the seller fails to provide sufficient cost-support, the Commission will direct the seller to submit a compliance filing to provide the formulas and methodology according to which it intends to calculate incremental costs.[808]

490. With regard to sales of greater than one week but less than one year, the Commission similarly requires that the seller submit a cost-based rate tariff for filing that identifies the methodology to be used to calculate the rate. When a seller adopts the default cost-based rate for mid-term sales (which is based on the unit or units expected to run), or otherwise proposes a cost-based rate designed on the unit or units expected to run, the Commission stated that it will continue to allow the seller flexibility in selecting the particular units that form the basis of the ''up to'' rate. However, as the Commission also stated in the Final Rule, it considers all evidence when reviewing a cost-based rate proposal and, if a company has not justified selection of certain generation units, the Commission will not accept the proposed rate.[809] Nevertheless, as with all cost-based mitigation proposals, the seller must file a cost-based rate tariff with the Commission and must provide cost support for such rates.[810] Accordingly, we clarify in response to NASUCA's request that when a mitigated seller files a cost-based mitigation proposal with the Commission, the seller must file an accompanying tariff.

491. We reject NASUCA's argument that there is no opportunity for public notice, or protest and Commission review of rates for mitigated sellers, and no opportunity for refund of unreasonable rates charged by sellers with market power for sales of up to one year's duration. As noted above and as discussed in the Final Rule, all mitigation proposals must be filed with the Commission for review.[811] These filings are noticed and interested parties are given an opportunity to intervene, comment or protest the submittal.[812] As the Commission stated in the Final Rule, it will continue to conduct its own analysis of whether a proposed cost-based rate is just and reasonable and, if warranted, will set such a proposed rate for evidentiary hearing where there are issues of material fact.[813] Under the FPA, the Commission has the authority to accept, reject, or modify a proposed rate based on the analysis of the specific facts and circumstances.[814] Contrary to NASUCA's contention that the Commission provides no opportunity for review of, and for refund of, rates charged by mitigated sellers for sales of up to one year's duration, the Commission has accepted, subject to refund, suspended and set for hearing cost-based mitigation proposals.[815]

492. We find NASUCA's reliance on *FPC* v. *Conway* to support its argument that the Commission should not grant mitigated sellers the flexibility to propose rates between marginal cost and embedded cost to be misplaced. In *FPC* v. *Conway*, the Supreme Court held that a utility could not set low retail rates to attract retail industrial customers from other utilities and set wholesale rates at prices higher than the retail rate so that its wholesale competitors could not compete in the retail market. The Court also held that, although the FPC lacked the authority to fix retail rates, it may take those rates into account when it fixes the rates for interstate wholesale sales that are subject to its jurisdiction.[816] As explained above, the Final Rule requires that the seller submit a cost-based rate tariff for filing that identifies the methodology to be used to calculate the rate for mid-term sales. Further, the Final Rule requires that, to the extent a seller proposes a cost-based rate formula, the rate formula to be used must be provided for Commission review and such formula must be included in the cost-based rate tariff, including formulas used in calculating incremental cost.[817] As the Final Rule explains, the Commission examines the proposed rate formulas of mitigated sellers on a case-by-case basis, and in doing so, fulfills its FPA mandate to ensure that rates are just and reasonable and not unduly discriminatory. Because the Final Rule requires sellers to submit a cost-based rate tariff for filing that identifies the methodology to be used to calculate the rate, and thereby does not permit sellers with market power to ''set rates at will,'' NASUCA's contention that allowing sellers with market power ''to set rates at will between marginal cost and embedded cost * * * could give the utility with wholesale market power the opportunity to extend it into retail markets'' is without merit. Thus, NASUCA's claim that a scenario resulting in potentially discriminatory or predatory conduct could occur is speculative and unsupported by the facts in the record.

493. We reject NASUCA's argument that allowing mitigated sellers to make sales for less than one year without filing them is a subdelegation to private parties of the duties conferred upon the Commission by Congress. NASUCA relies on *ISO New England, Inc.*[818] to support its argument in this regard. In *ISO New England, Inc.*, the Commission preauthorized ISO New England to enter into mitigation agreements intended to mitigate generation resources that ran out-of-economic merit order during periods of transmission constraints, and concluded that all such agreements were just and reasonable. On appeal, the D.C. Circuit remanded to the Commission the issue concerning whether the rates adopted in mitigation agreements were just and reasonable because the Commission had not reviewed data concerning generator costs for the rates in the mitigation agreements.[819] Contrary to NASUCA's argument, and unlike the situation in *ISO New England, Inc.*, the Final Rule states that ''where a seller proposes to adopt the default cost-based rates (or where it proposes other cost-based rates), it must provide cost support for such rates. The Commission will

[806] *Id.* P 629.

[807] *Id.* P 630 (citing April 14 Order, 107 FERC ¶ 61,018 at P 208; *Entergy Services, Inc.,* 115 FERC 61,260 at P 49 (2006) (accepting cost-based rates based on incremental cost plus 10 percent, noting that filing included the formula and methodology according to which seller intends to calculate incremental costs)).

[808] *Id.* P 630 (citing *Aquila, Inc.,* 112 FERC ¶ 61,307, at P 26 (2005); *Oklahoma Gas and Electric Co.,* 114 FERC ¶ 61,297, at P 19 (2006)).

[809] *Id.* P 649, 651.

[810] As explained in the Final Rule, upon loss or surrender of market-based rate authority a seller has a number of options of how to make wholesale power sales. It can revert to a cost-based rate tariff on file with the Commission, file a new proposed cost-based rate tariff, or propose other mitigation. *See* Order No. 697 at n.699.

[811] Order No. 697 at P 629.

[812] *Id.*

[813] *Id.* P 650.

[814] *Id.* P 651.

[815] *See Id.* P 631 (citing *AEP Power Marketing, Inc.,* 112 FERC ¶ 61,047, at P 28 (2005) (accepting, subject to refund, and setting for hearing, AEP's proposed rate for sales of power of more than one week but less than one year upon finding that AEP did not provide sufficient cost support for the rate levels proposed). *See also, Duke Power,* 113 FERC ¶ 61,192, at P 38 (2005).

[816] 426 U.S. 271, 279–80 (1976).

[817] Order No. 697 at P 630.

[818] 818 112 FERC ¶ 61,057 (2005), *reversed in part*, *NSTAR*, 481 F.3d 794.

[819] *NSTAR*, 481 F.3d 794.

examine the proposed rates on a case-by-case basis.'' [820] Here, the Commission has *not* neglected to review a mitigation proposal, or the cost support for such a proposal. Rather, it is promulgating a rule which provides for Commission examination of rates proposed by mitigated sellers, and that requires cost support for such rates. Thus, NASUCA's argument in this regard is without merit.

494. Further, as explained above, the Final Rule retained the Commission's current policy of pricing sales of more than one week but less than one year at an embedded cost ''up to'' rate reflecting the costs of the generating unit(s) expected to provide the service.[821] Although this approach allows sellers flexibility in designing ''up to'' rates for purposes of mitigation for sales of more than one week but less than one year, such rates are still subject to Commission review and approval.[822] The Commission considers all evidence when reviewing a cost-based rate proposal and, if a company has not justified selection of certain generating units, we will not accept the proposed rate. Under the FPA, we have the authority to accept, reject, or modify a proposed rate based on an analysis of the specific facts and circumstances.[823] NASUCA relies on *U.S. Telecomm. Ass'n* v. *FCC*,[824] and Chairman Kelliher's dissent in *ISO New England Inc.* to support its contention that the Commission may not delegate its authority to private parties. As we explain above, however, because the Final Rule provides for Commission review of a seller's proposed rates, and because the Commission will not accept the proposed rate if a company has not justified selection of certain generating units, the Final Rule is not subdelegating the Commission's duties.[825]

495. We also reject NASUCA's argument that under the Final Rule, rates of mitigated sellers rely on private parties to negotiate and charge reasonable rates and thereby are in contravention of the holdings of *MCI* and *Electrical District.* In *MCI*, the Supreme Court rejected an FCC policy that relieved all non-dominant carriers of any requirement to file any of their rates with the agency. *Electrical District* holds that the Commission cannot, in a proceeding under section 206, ''announce some formula and *later* reveal that formula was to govern from the date of announcement.''[826] Both of these cases are distinguishable from the mitigation scheme set forth in the Final Rule. Because the Final Rule explains that ''all mitigation proposals must be filed with the Commission for review'' and states that ''[t]hese filings will be noticed and interested parties will be given an opportunity to intervene, comment, or protest the submittal'' [827] the Final Rule does not rely on private parties to negotiate and charge reasonable rates and does not contravene the holdings in *MCI* and *Electrical District.*

3. Whether Existing Tariffs Must Be Found To Be Unjust and Unreasonable, and Whether the Commission Must Establish a Refund Effective Date

Final Rule

496. The Final Rule determined that the Commission was not required to establish a refund effective date and concluded that continuing to allow basic inconsistencies in the market-based rate tariffs on file with the Commission is unjust and unreasonable.[828] The Commission found that even if section 206 were read to require the establishment of a refund effective date in rulemakings initiated under section 206, rather than only in case-specific section 206 investigations initiated by complaints or *sua sponte* by the Commission, the Commission has broad discretion to adopt a generic policy or make generic findings through either rulemaking or adjudication.[829] The Commission concluded that ''[t]his proceeding is not an adjudicatory investigation of public utilities' existing market-based rate tariffs for which refunds will be required. Rather, we are modifying existing market-based rate tariffs *prospectively only* through this rulemaking. Accordingly, the establishment of a refund effective date in this rulemaking would be meaningless.'' [830]

Requests for Rehearing

497. Consumer Advocates contend that the Final Rule points to no specific legal authority under either section 205 or 206 that supports the Commission's action. They state that the Commission claims it is not ''adjudicating'' in the Final Rule, but fails to recognize that the Commission's authority to issue rules under sections 205 and 206 is narrowly constrained because the Commission has no independent ratemaking power under the FPA.[831] Consumer Advocates state that pursuant to *United Gas Pipe Line* and *Sierra*, the Commission has authority under section 206(a) to review initial rates and contracts filed by utility sellers, or ongoing, previously effective rates. Consumer Advocates contend that before the Commission can act under section 206(a), it must find existing rates to be unlawful, and also must find market-based rates as modified by the rulemaking to be just and reasonable and not unduly preferential or discriminatory going forward. They submit that although the Final Rule purports to make the first finding that existing rates without the new rules are unjust and unreasonable, it fails to make the second finding that market-based rates that adhere to the Final Rule are just and reasonable.[832] Consumer Advocates contend that the Final Rule pointed to no legal authority under section 205 or 206 that supports the actions taken, but instead points only to policy choices regarding the market-based rate regime. Consumer Advocates assert that the Commission has no authority, even to implement policy, unless the statute confers it.[833]

Commission Determination

498. We disagree with Consumer Advocates' contentions that the Commission must find existing market-based rates to be unlawful and must set new lawful rates going forward and that the Commission has no authority to implement the policies in this rulemaking. We have broad discretion to adopt generic policy or make generic findings through either rulemaking or adjudication,[834] and we have discretion over whether to order refunds.[835] We

[820] Order No. 697 at P 630.

[821] Order No. 697 at P 648.

[822] *Id.* P 652.

[823] *Id.* P 651.

[824] 359 F.3d 554 (D.C. Cir. 2004) (finding that a federal agency may not delegate its authority to outside entities).

[825] *See* Order No. 697 at P 629, 651.

[826] *Transwestern Pipeline Co.* v. *FERC*, 897 F.2d 570, 578 (D.C. Cir. 1990). *See supra* P 453.

[827] Order No. 697 at P 629.

[828] *Id.* P 974.

[829] *Id.* P 975 (citing *Lockyer*).

[830] *Id.* (citing *Wisconsin Gas Co.* v. *FERC*, 770 F.2d 1144, 1166 (D.C. Cir. 1985); *SEC* v. *Chenery*, 332 U.S. 194, 202–03, *reh'g denied*, 332 U.S. 747 (1947) (emphasis in original).

[831] *Id.* at 16 (citing *United Gas Pipe Line*; *Sierra*).

[832] *Id.* (citing *United Gas Pipe Line*; *Sierra*).

[833] *Id.* at 17 (citing *Atlantic City Electric Co.* v. *FERC*, 295 F.3d 1, 8 (D.C. Cir. 2002) (*Atlantic City*)).

[834] An agency enjoys broad discretion to determine its own procedures, including whether to act by a generic rulemaking or by case-by-case adjudication. *Mobil Oil Exploration & Producing Southeast, Inc.* v. *United Distrib. Cos.*, 498 U.S. 211, 230 (1991); *NLRB* v. *Bell Aerospace Co.*, 416 U.S. 267, 293 (1974); *Interstate Natural Gas Association of America* v. *FERC*, 285 F.3d 18, 57–58 (D.C. Cir. 2001).

[835] *See* e.g., *Lockyer*, 383 F.3d at 1016. Consumer Advocates rely on *Atlantic City* for support for their argument that the Commission has no authority to implement policy unless a statute confers it. In *Atlantic City*, the court held that the Commission did not have authority to require utilities to give up their right to file rate changes or authority to mandate that withdrawal from an ISO could only become effective upon Commission approval. However, because the courts have repeatedly

Continued

reiterate that this proceeding is not an adjudicatory investigation of public utilities' existing market-based rate tariffs for which refunds will be required.[836]

499. We also reject Consumer Advocates' assertion that the instant rulemaking is in contravention of *United Gas Pipe Line* and *Sierra* because the Final Rule did not make the finding that market-based rates that adhere to the Final Rule are just and reasonable. In *United Gas Pipe Line*, the Supreme Court interpreted provisions of the NGA that parallel the FPA, and it stated that section 4(d) of the NGA says only that "a change in the filed rate *cannot* be made without proper notice to the Commission." [837] The Supreme Court held in *Sierra* that the FPA does not authorize unilateral contract changes and held that the Federal Power Commission could not declare a rate set by a contract to be "unreasonable solely because it yields less than a fair return on the next invested capital." [838] Unlike *United Gas Pipe Line* and *Sierra*, this rulemaking proceeding is not an adjudicatory investigation of a public utility's existing rates for which refunds will be required. Rather, in the Final Rule the Commission revised and codified its market-based rate policy for public utilities on a generic basis. Contrary to Consumer Advocates' argument that the Commission did not specify "exactly what it is doing in the Final Rule," the Commission clearly stated that it is "modifying existing market-based rate tariffs *prospectively only* through this rulemaking." [839]

G. Miscellaneous

1. Change in Status

a. Reporting

Final Rule

500. In Order No. 697, the Commission continued its requirement for sellers to report any change in status that departs from the characteristics relied upon by the Commission in authorizing sales at market-based rates.[840] Events that constitute a change in status include, among other things, ownership or control of generation capacity that result in net increases of 100 MW or more, and change in upstream ownership. Notification of any such changes in status must be filed no later than 30 days after the change occurs.

501. Also in Order No. 697, the Commission created a category of market-based rate sellers that are exempt from the requirement to submit regularly scheduled updated market power analyses. These Category 1 sellers have been carefully defined by the Commission to have attributes that are not likely to present market power concerns.[841] Market power concerns for Category 1 sellers are monitored by the Commission through the change in status reporting requirement and through ongoing monitoring by the Commission's Office of Enforcement. All other sellers, Category 2 sellers, are, in addition, required to continue to file regularly scheduled updated market power analyses.[842]

Requests for Rehearing

502. TDU Systems assert that to protect consumers more adequately, the Commission should require a Category 2 seller to submit an updated market power analysis in each instance in which a seller's generation increases by a predetermined percentage or an absolute amount.[843] TDU Systems state that under the Commission's present rules, a public utility that builds or acquires new generation capacity or merges with another company is not required to submit a new horizontal market power analysis. It is required only to file a change in status report for any net increase of 100 MW or more. TDU Systems references a proposal made by another commenter in response to the NOPR asking the Commission to require an updated market power analysis in each instance in which a seller's generation increases by a predetermined percentage or absolute amount. According to TDU Systems, the Commission did not directly address this proposal in the Final Rule,[844] but indirectly touched on the issue by stating that an updated market power analysis may be required from any sellers, Category 1 or 2, at any time.

503. TDU Systems assert that the Commission erred in failing to address the merits of this proposal in the Final Rule.[845] They contend that the Commission should not burden itself with deciding when major additions to generation, revealed in a change in status report, are likely to alter the results of its market power tests. They submit that it would not be an unreasonable burden on Category 2 sellers to prepare updated analyses within a reasonable time from the acquisition of additional generation.

Commission Determination

504. In the Final Rule, the Commission stated that it retains the tools necessary to ensure that all rates are just and reasonable, with initial market power evaluations, ongoing monitoring by the Commission, change in status reporting requirements, and scheduled updated market power analyses for Category 2 sellers.[846] We continue to believe that these requirements provide the Commission with the tools it needs to ensure that rates remain just and reasonable.

In Order No. 652, the Commission clarified and standardized market-based rate sellers' reporting requirement for changes in status and the Commission considered and rejected the idea that change in status filings include an updated market power analysis. The Commission explained that it is incumbent on an applicant to decide whether a change in status is a material change and that an applicant should provide adequate support and analysis, including an updated market power analysis if it chooses.[847] Thus, if a market-based rate seller believes that a change in status does not affect the continuing basis of the Commission's grant of market-based rate authority, it should clearly state the reasons on which it bases this conclusion, including an updated market power analysis if it so chooses.

505. While we appreciate TDU Systems' proposal and agree that it would not necessarily be an unreasonable burden to require Category 2 sellers to prepare updated analyses within a reasonable time from the acquisition of additional generation, we are not persuaded that our current approach is not adequate. The existing reporting requirement provides the

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upheld the Commission's authority to adopt market-based rates, Consumer Advocates' reliance on *Atlantic City* for support for their argument in this regard is misplaced. *See*, e.g., *LEPA*, 141 F.3d 364; *Lockyer*, 383 F.3d 1006; *Snohomish*, 471 F.3d 1053.

[836] Order No. 697 at P 975.

[837] *United Gas Pipe Line*, 350 U.S. at 339 (emphasis in original).

[838] *Sierra*, 350 U.S. at 355.

[839] Order No. 697 at P 975 (citing *Wisconsin Gas Co.* v. *FERC*, 770 F.2d 1144, 1166 (D.C. Cir. 1985); *SEC* v. *Chenery*, 332 U.S. 194, 202–03, *reh'g denied*, 332 U.S. 747 (1947) (emphasis in original)).

[840] Order No. 697 at P 1009–1045 (codifying the requirement, as amended, at 18 CFR 35.42).

[841] *Id.* at P 853.

[842] Previously, updated market power analyses were submitted within three years of any order granting a seller market-based rate authority, and every three years thereafter.

[843] TDU Systems at 28 (citing NRECA NOPR comments at 24. NRECA gives examples of predetermined thresholds as a certain percentage increase over the current amount, or any increase over some absolute amount).

[844] TDU Systems indicate that NRECA suggested this proposal. TDU Systems at 27–28 (citing NRECA NOPR comments at 23–25).

[845] *Id.* at 4–5 (citing *K N Energy, Inc.* v. *FERC*, 968 F.2d 1295, 1303 (D.C. Cir. 1991)).

[846] Order No. 697 at P 853–854.

[847] Order No. 652, FERC Stats. & Regs. ¶ 31,175 at P 94–95.

Commission a sufficient tool to allow it to assess whether there is a potential market power concern and, if so, the Commission reserves the right to require the seller to submit a market power study. In addition, the seller is required to provide an affirmative statement as to what effect, if any, the added generation has on its market power. For a seller to make such an affirmative statement, it must determine what effect the added generation has on the market power analysis. To the extent the seller makes an affirmative statement that there is no effect on its market power, it is bound to that statement and faces remedial action, including civil penalties, if it has misrepresented the effect.

506. Therefore, we will not require entities to automatically file an updated market power analysis with their change in status filings, such as that required by a triennial review. However, an entity may provide such an analysis if it chooses. Furthermore, regardless of the seller's representation, if the Commission has concerns with a change in status filing (for example, market shares are below 20 percent, but are relatively high nonetheless), the Commission retains the right to require an updated market power analysis at any time.[848]

b. Transmission Outages

Final Rule

507. The Final Rule adopted the NOPR proposal not to require the reporting of transmission outages per se as a change in status. The Commission explained that the reporting of all transmission outages, including the most routine, would be an excessive burden on sellers with no apparent countervailing benefit. However, the Final Rule stated that, consistent with Order No. 652, to the extent that a long-term transmission outage affects one or more of the factors of the Commission's market-based rate analysis (e.g., if it reduces imports of capacity by competitors that, if reflected in the generation market power screens, would change the results of the screens from a ''pass'' to a ''fail''), a change in status filing is required.[849]

Requests for Rehearing

508. Wisconsin Electric requests that the Commission clarify which entity is responsible for reporting long-term transmission outages as a change in status. Wisconsin Electric explains that companies such as itself that do not own transmission may not be in the position of knowing the details of transmission outages and the effects of an outage on their market power analyses. Therefore, Wisconsin Electric requests that the Commission clarify that non-transmission owning entities such as itself need not report long-term outages.[850]

Commission Determination

509. The Final Rule did not expand the events that trigger a change in status filing to include actions taken by a competitor (such as a decision to take transmission capacity out of service), beyond those adopted in Order No. 652. Furthermore, the Commission found that it is not reasonable to routinely require sellers to make a showing regarding potential barriers to entry that others might erect or are beyond the seller's control.[851] Thus, as a general matter, a transmission outage that occurs beyond a seller's control does not necessarily trigger a change in status filing.[852] In certain circumstances, however, a seller, including a non-transmission owning entity, will be required to submit a change in status filing, as stated above,[853] when it or its affiliate know that a long-term transmission outage has an effect on its market power analysis (e.g., the long-term transmission outage causes the seller to fail one or more of the indicative screens).

c. Other Clarifications

510. Below we provide a number of other clarifications regarding the change in status reporting requirement. Although no clarifications or rehearing requests were submitted on these particular issues, the Commission is aware of some confusion in the industry and accordingly provides clarification.

Change in Status Reporting by Market

511. As codified in § 35.42 of the Commission's regulations, events that constitute a change in status include, among other things, changes in ownership or control of generation capacity that result in net increases of 100 MW or more.[854]

512. We clarify that a change in status should be filed to reflect a change in the ownership or control of generation capacity that results in a net increase of 100 MW or more in the geographic market that was the subject of the horizontal market power analysis on which the Commission relied in granting the seller market-based rate authority. For example, if the Commission relied on a seller's default geographic market in granting the seller market-based rate authority, the seller would be required to submit a change in status filing for a net increase of 100 MW or more of generation capacity in that geographic market. Similarly, if the Commission relied upon an alternative geographic market in granting a seller market-based rate authority, any net increase of 100 MW or more of generation capacity in the alternative geographic market would require the seller to submit a change in status filing. On the other hand, if a seller has a net increase of 50 MW in the geographic market on which the Commission relied in granting the seller market-based rate authority and a 50 MW increase in a different geographic market that is in the same region as defined by Appendix D of Order No 697, the 100 MW or more threshold would not be met because the increase in generation capacity is less than 50 MW in each generation market and, accordingly, a change in status filing would not be required.

Change in Status Reporting Cumulatively

513. A seller must submit an initial application to receive market-based rate authority and file change in status filings in compliance with its market-based rate authority, such as an increase of 100 MW or more in a geographic market. However, in the course of processing change in status filings made by sellers, the Commission believes that it has not been clear to some sellers that increases in generation should be reported cumulatively. For example, some sellers have submitted a series of change in status reports that consider only the additional capacity on a standalone basis rather than considering the total effect of each generation capacity increase since the seller's last market power analysis. When a seller submits a change in status filing to report an increase of 100 MW or more of generation capacity in a geographic market, rather than treating each increase in generation capacity on a standalone basis, the seller should consider the cumulative effect of all increases in generation capacity since its most recently approved market power analysis.

514. For example, if a seller acquires generation capacity resulting in a net increase of 100 MW in a market in January, it is required to submit a change in status filing reflecting this net

[848] Order No. 697 at P 856–857.

[849] Order No. 697 at P 1025.

[850] Wisconsin Electric at 4–5.

[851] Order No. 697 at P 1035.

[852] We clarify that, to the extent the Commission becomes aware of a possible barrier to entry such as a long-term transmission outage, the Commission reserves the right to require any market-based rate seller to demonstrate what effect, if any, that barrier to entry has on its ability to exercise market power.

[853] Order No. 652, FERC Stats. & Regs. ¶ 31,175 at P 75.

[854] *Id.* at P 68.

increase. However, if the seller adds an additional 100 MW of generation in the same market in February, the seller must account for a cumulative total of 200 MW in that market when submitting its change in status filing for the February addition of generation capacity. This cumulative net increase since a seller's most recently approved market power analysis must be the basis of the seller's change in status to reflect that it does or does not depart from the characteristics the Commission relied on in authorizing sales at market-based rates.

2. Third Party Providers of Ancillary Services

Final Rule

515. In the Final Rule, the Commission modified its approach for third-party sellers of ancillary services at market-based rates as announced in *Avista*.[855] The Commission noted that the posting and reporting requirements imposed in *Avista* may be hindering the development of ancillary services markets, particularly by third-party providers. Thus, the Commission concluded that the EQR filing requirement provides an adequate means to monitor ancillary services sales by third parties such that the posting and reporting requirements established in *Avista* are no longer necessary.[856]

516. In the Final Rule, the Commission stated that all sellers that seek authority to sell ancillary services at market-based rates pursuant to *Avista*[857] must make a filing with the Commission to request that authority and must include language in their market-based rate tariffs identifying the ancillary services that they offer.[858] Moreover, the Final Rule retained the Commission's current policy of not allowing sales of ancillary services by a third-party supplier in the following situations: (1) Sales to an RTO or an ISO, *i.e.*, where that entity has no ability to self-supply ancillary services but instead depends on third parties; (2) sales to a traditional, franchised public utility affiliated with the third-party supplier, or sales where the underlying transmission service is on the system of the public utility affiliated with the third-party supplier; and (3) sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers.[859] Standard applicable tariff provisions to this affect appear in Appendix C of the Final Rule and must be included in the tariffs of any entities that sell ancillary services at market-based rates. The Commission reiterated that it is open to considering requests for market-based rate authorization to make such sales on a case-by-case basis.[860]

Requests for Rehearing

517. Wisconsin Electric requests that the Commission clarify that its decision to eliminate the posting and reporting requirements of *Avista* extends to providers of ancillary services that provide ancillary services other than the four services addressed in *Avista*.[861] Wisconsin Electric states that it is a third-party provider of ancillary services and received Commission authorization to offer the four services addressed in *Avista*, but it also received the authorization to offer Dynamic Capacity and Energy Service as an ancillary service, conditioned upon the requirements in *Avista* to establish and maintain an Internet-based site and to file periodic reports describing the company's activities in the ancillary services markets.[862] Wisconsin Electric requests that the Commission clarify that the decision to remove the *Avista* posting and reporting requirements pertains not only to the four ancillary services specifically mentioned in *Avista*, but also to the other ancillary services to which the Commission subsequently applied the *Avista* requirements.[863]

518. Morgan Stanley seeks to clarify its own request to the Commission to identify ways to encourage more robust ancillary services markets outside of RTO/ISO control areas. Morgan Stanley states that its request was intended to support the creation of physically-settled bilateral ancillary services markets, not a market for financially-settled products that are beyond the Commission's jurisdiction.[864]

519. Furthermore, Morgan Stanley clarifies that it continues to regard the creation of a robust bilateral market for physically-settled ancillary services, particularly outside of ISOs and RTOs, as the next step to facilitating greater competition in the wholesale energy markets overall. It did not, however, provide details for specific ancillary services proposals, other than the elimination of the *Avista* posting requirement, because its comments were intended solely to show support for a policy position. Thus, Morgan Stanley reaffirms its prior request that the Commission continue to look for opportunities to jump-start competition in the physical ancillary services markets throughout the United States.[865]

Commission Determination

520. We will grant Wisconsin Electric's request for clarification. As the Commission stated in the Final Rule, the ancillary services addressed in *Avista* are Regulation Service, Energy Imbalance Service, Spinning Reserves, and Supplemental Reserves. In *Avista* however, the Commission also characterized Dynamic Capacity and Energy Service as an ancillary service stating it is a combination of two ancillary services, Regulation Service and Energy Imbalance Service, and is intended to satisfy the transmission provider's option to allow customers to supply ancillary services to the system directly. As such, Dynamic Capacity and Energy Service is an approved ancillary service conditioned upon the requirements and limitations of *Avista*.[866] Similarly, in *Wisconsin Electric Power Co.*, the Commission authorized Wisconsin Electric to provide Dynamic Capacity and Energy Service as an ancillary service conditioned upon *Avista*.[867]

521. Therefore, because Dynamic Energy and Capacity Service, as

[855] Order No. 697 at P 1058. *See Avista Corporation,* 87 FERC ¶ 61,223 (*Avista*), *order on reh'g,* 89 FERC ¶ 61,136 (*Avista II*) (1999).

[856] With this modification adopted in the Final Rule of eliminating the specific posting and reporting requirements established in *Avista* for third-party sellers of ancillary services, the Commission expects to monitor ancillary services sales by third parties through the EQR. In a notice seeking comments on proposed revisions to the EQR Data Dictionary, *Revised Public Utility Filing Requirements for Electric Quarterly Reports,* 122 FERC ¶ 61,194 (2008), the Commission is seeking comment on proposed changes that would clarify that the ancillary services discussed in Avista must be reported whenever those services are provided. Under the proposed revisions, when a seller makes third-party sales of ancillary services, that seller would be required to file, in its EQR, transaction information including (but not limited to) the purchaser, the ancillary service provided, and the price of the service. (*See http://www.ferc.gov/docs-filing/eqr.asp* for more information on EQR filings).

[857] The *Avista* policy applies to the following four ancillary services: Regulation Service, Energy Imbalance Service, Spinning Reserves, and Supplemental Reserves.

[858] Order No. 697 at P 1060. Sellers that have been granted authority to provide third-party ancillary services need not reapply because their authority continues.

[859] Order No. 697 at P 1061 (citing *Avista*, 87 FERC ¶ 61,223 at 61,883, n. 12).

[860] *Id.*

[861] Wisconsin Electric Rehearing Request at 3.

[862] *Id.* at 4 (citing *Wisconsin Electric Power Co.*, 93 FERC ¶ 61,302 (2000)).

[863] *Id.*

[864] Morgan Stanley Rehearing Request at 1, 4.

[865] *Id.* at 5.

[866] *Avista II*, 89 FERC ¶ 61,136 at 61,392.

[867] *Wisconsin Electric Power Co.*, 93 FERC ¶ 61,302 (2000).

described in *Avista,* was authorized by the Commission as an ancillary service pursuant to the *Avista* policy, consistent with the Final Rule, such sellers may continue to sell this ancillary service at market-based rates and are no longer required to meet the *Avista* posting and reporting requirements with regard to this service. The current EQR Data Dictionary does not include Dynamic Energy and Capacity Service in the standard list of products because this service is only offered by a few companies. However, the Commission invited comments on adding new ancillary service names in Docket No. RM01–8–009.[868] Absent the addition of a specific EQR Product Name, sellers offering this service must report it as an ''Other'' product in both the contract and transaction sections of their EQR.

522. We appreciate Morgan Stanley's clarification of its intent to support the creation of physically-settled bilateral ancillary services markets but the formation of such markets is beyond the scope of this proceeding.

3. Requesting Market-Based Rate Authority for QFs

523. The Final Rule amended the Commission's regulations governing market-based rate authorizations for wholesale sales of electric energy, capacity and ancillary services by public utilities. Although the Final Rule did not address the specific applicability of market-based rate authority to QFs, below we address sales by QFs at market-based rates that are subject to the Commission's jurisdiction.

524. QFs making certain sales of energy,[869] as defined below, are exempt from sections 205 and 206 of the FPA. These QF exemptions are applicable to some sales at market-based rates.[870] Therefore, sales of a QF that meet specific criteria are exempt from section 205 and a QF is authorized to make those sales at market-based rates without making a section 205 filing.

525. All sales of energy or capacity made by QFs 20 MW or smaller are exempt from section 205. Sales from a QF larger than 20 MW are exempt from section 205 only if those sales are made pursuant to a state regulatory authority's implementation of PURPA, or if those sales are made pursuant to a contract executed on or before March 17, 2006[871] (unless the sale is from a qualifying small power production facility with a power production capacity which exceeds 30 MW, if such facility uses any primary energy source other than geothermal resources, in which case the sale is not exempt).[872] If a QF's sales are not exempt from section 205, but the QF would like to make sales at market-based rates, the QF is required to request market-based rate authority.[873]

526. When a QF submits an application for market-based rate authority, its application must fulfill the requirements in Order No. 697, as required by all applicants. A QF, however, must also inform the Commission in its market-based rate application of its QF status and explain its request to transact under market-based rates. For example, a QF must explain whether any of its sales meet the requirements for the exemption from section 205 contained in 18 CFR 292.601(c)(1). Furthermore, if a QF desires to make certain energy sales at market-based rates, while making other sales exempt from section 205, the QF must list its limitations on sales at market-based rates in its market-based rate tariff (*i.e.,* sales under Seller's contract (Contract X), which was executed on March 17, 2006, are exempt from section 205 and sales outside of Contract X would be under market-based rates) and cite to the Commission orders certifying or recertifying its QF status, and/or to the docket numbers in which it self-certified or self-recertified its QF status, as explained in Order No. 697.[874]

H. Clarifications of the Commission's Regulations

527. The Commission finds, based on its further consideration of the regulations, that several provisions should be changed to provide additional clarity.

528. First, one of the affiliate restrictions codified in the Final Rule contained some minor omissions. Section 35.39(b) restricts sales between a franchised public utility with captive customers and a market-regulated power sales affiliate unless the seller first receives Commission authorization for the transaction under section 205 of the FPA. Upon further review, the Commission notes that the phrase ''or capacity'' should be added to the term ''wholesale sales of electric energy'' to ensure that the provision covers the appropriate scope of affiliate sales. Therefore, we will amend § 35.39(b) accordingly.

529. Second, in the Final Rule, the Commission adopted a regulation requiring sellers to timely report to the Commission any change in status that would reflect a departure from the characteristics the Commission relied upon in granting market-based rate authority. In particular, § 35.42 specifies that a change in status includes, but is not limited to, ownership or control of generation capacity that results in net increases of 100 MW or more.

530. Upon further consideration, the Commission recognizes that this provision deserves additional clarity. We take this opportunity to clarify that a change in status also includes long-term firm capacity purchases that result in net increases of 100 MW or more. This is consistent with a seller's obligation to include long-term firm capacity purchases in determining uncommitted capacity, which is used in the indicative screens.[875] We believe that revision to the regulation is appropriate because the Commission's April 14 Order, reaffirmed in Order No. 697, stated that uncommitted capacity is determined ''by adding the total nameplate or seasonal capacity of generation owned or controlled through contract and firm purchases, less operating reserves, native load commitments and long-term firm sales.''[876]

531. Thus, long-term firm capacity purchases that result in net increases of 100 MW or more are a ''departure from the characteristics the Commission relied upon in granting market-based rate authority.'' Accordingly, § 35.42(a)(1) is revised so that a change in status includes, but is not limited to, ownership or control of generation capacity and long-term firm purchases of generation capacity that result in net increases of 100 MW or more. Because sellers may not have been on notice that this was the Commission's intent, we will not hold any sellers responsible for failure to report such changes in status prior to the effective date of this order,

[868] *Revised Public Utility Filing Requirements for Electric Quarterly Reports*, 73 FR 12983 (Mar. 11, 2008), FERC Stats. & Regs. ¶ 35,557 (Mar. 3, 2008) (seeking comments on proposed revisions to EQR Data Dictionary).

[869] In the context of PURPA, the term energy includes capacity, energy and ancillary services.

[870] *See* 18 CFR 292.601(c)(1).

[871] *Id.*

[872] 18 CFR 292.601(b). However, a qualifying facility that is an eligible solar, wind, waste, or geothermal facility, as defined by section 3(17)(E) of the Federal Power Act, is not subject to the 30 MW size limitation imposed by 18 CFR 292.601(b). *See Cambria Cogen Company,* 53 FERC ¶ 61,459 (1990).

[873] We note that the Commission has previously granted market-based rate authority to QFs that are larger than 20 MW for sales of excess power. The Commission has also rejected requests for market-based rate authority from QFs that are exempt from section 205. *See,* e.g., *SP Newsprint,* 103 FERC ¶ 61,186 (2003).

[874] Order No. 697 at P 916–17.

[875] *See* April 14 Order, 107 FERC ¶ 61,018 at P 95, 100.

[876] *See* Order No. 697 at P 38 (emphasis added; footnote omitted).

which will be 30 days after issuance in the **Federal Register**.

532. Third, as explained earlier in the affiliate abuse section of this order, we are revising the definition of captive customers and adding a definition for affiliate. We will revise the definition of captive customers in § 35.36(a)(6) to mean any wholesale or retail electric energy customers served *by a franchised public utility* under cost-based regulation, to be consistent with the discussion in the Affiliate Transactions Final Rule and the definition of captive customers adopted in that rule at 18 CFR 35.42(a)(2). The definition of affiliate as that term is used in the Affiliate Transactions Final Rule will be codified at paragraph 35.36(a)(9).

533. Fourth, we are revising § 35.39(d)(1) to reflect the determination to adopt a one-way information sharing restriction. Finally, as discussed in the vertical market power section of this order, we are revising the definition of inputs to electric power production to clarify the types of coal supply that are intended to be included in the definition.

III. Information Collection Statement

534. The Office of Management and Budget (OMB) regulations require that OMB approve certain information collection requirements imposed by an agency.[877] The Final Rule's revisions to the information collection requirements for market-based rate sellers were approved under OMB Control Nos. 1902–0234. While this order clarifies aspects of the existing information collection requirements for the market-based rate program, it does not add to these requirements. Accordingly, a copy of this order will be sent to OMB for informational purposes only.

IV. Document Availability

535. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (*http://www.ferc.gov*) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5 p.m. Eastern time) at 888 First Street, NE., Room 2A, Washington, DC 20426.

536. From FERC's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

537. User assistance is available for eLibrary and the FERC's Web site during normal business hours from FERC Online Support at 202–502–6652 (toll free at 1–866–208–3676) or e-mail at *ferconlinesupport@ferc.gov,* or the Public Reference Room at (202) 502–8371, TTY (202) 502–8659. E-mail the Public Reference Room at *public.referenceroom@ferc.gov.*

V. Effective Date

538. Changes to Order No. 697 adopted in this order on rehearing will become effective June 6, 2008.

List of Subjects in 18 CFR Part 35

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

By the Commission. Commissioner Kelly concurring with a separate statement attached.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

■ In consideration of the foregoing, the Commission amends part 35, Chapter I, Title 18, *Code of Federal Regulations*, as follows:

PART 35—FILING OF RATE SCHEDULES AND TARIFFS

■ 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. 7101–7152.

■ 2. In § 35.36, paragraphs (a)(4) and (a)(6) are revised and paragraph (a)(9) is added to read as follows:

§ 35.36 Generally.

(a) * * *

(4) *Inputs to electric power production* means intrastate natural gas transportation, intrastate natural gas storage or distribution facilities; sites for generation capacity development; physical coal supply sources and ownership of or control over who may access transportation of coal supplies.

* * * * *

(6) *Captive customers* means any wholesale or retail electric energy customers served by a franchised public utility under cost-based regulation.

* * * * *

(9) *Affiliate* of a specified company means:

(i) For any person other than an exempt wholesale generator:

(A) Any person that directly or indirectly owns, controls, or holds with power to vote, 10 percent or more of the outstanding voting securities of the specified company;

(B) Any company 10 percent or more of whose outstanding voting securities are owned, controlled, or held with power to vote, directly or indirectly, by the specified company;

(C) Any person or class of persons that the Commission determines, after appropriate notice and opportunity for hearing, to stand in such relation to the specified company that there is liable to be an absence of arm's-length bargaining in transactions between them as to make it necessary or appropriate in the public interest or for the protection of investors or consumers that the person be treated as an affiliate; and

(D) Any person that is under common control with the specified company.

(E) For purposes of paragraph (a)(9)(i), owning, controlling or holding with power to vote, less than 10 percent of the outstanding voting securities of a specified company creates a rebuttable presumption of lack of control.

(ii) For any exempt wholesale generator (as defined under § 366.1 of this chapter):

(A) Any person that directly or indirectly owns, controls, or holds with power to vote, 5 percent or more of the outstanding voting securities of the specified company;

(B) Any company 5 percent or more of whose outstanding voting securities are owned, controlled, or held with power to vote, directly or indirectly, by the specified company;

(C) Any individual who is an officer or director of the specified company, or of any company which is an affiliate thereof under paragraph (a)(9)(ii)(A); and

(D) Any person or class of persons that the Commission determines, after appropriate notice and opportunity for hearing, to stand in such relation to the specified company that there is liable to be an absence of arm's-length bargaining in transactions between them as to make it necessary or appropriate in the public interest or for the protection of investors or consumers that the person be treated as an affiliate.

* * * * *

■ 3. In § 35.39, paragraphs (b) and (d)(1) are revised to read as follows:

§ 35.39 Affiliate restrictions.

* * * * *

(b) *Restriction on affiliate sales of electric energy or capacity.* As a condition of obtaining and retaining market-based rate authority, no wholesale sale of electric energy or capacity may be made between a franchised public utility with captive customers and a market-regulated power sales affiliate without first receiving

[877] 5 CFR 1320.11.

Commission authorization for the transaction under section 205 of the Federal Power Act. All authorizations to engage in affiliate wholesale sales of electric energy or capacity must be listed in a Seller's market-based rate tariff.

* * * * *

(d) *Information sharing.*

(1) A franchised public utility with captive customers may not share market information with a market-regulated power sales affiliate if the sharing could be used to the detriment of captive customers, unless simultaneously disclosed to the public.

* * * * *

■ 4. In § 35.42, paragraph (a)(1) is revised to read as follows:

§ 35.42 Change in status reporting requirement.

(a) * * *

(1) Ownership or control of generation capacity and long-term firm purchases of generation capacity that result in net increases of 100 MW or more, or of inputs to electric power production, or ownership, operation or control of transmission facilities, or

* * * * *

■ 5. Appendix A of subpart H is revised to read as follows:

Appendix A to Subpart H

Appendix A

Standard Screen Format

(Data provided for Illustrative Purposes only)

PART I.—PIVOTAL SUPPLIER ANALYSIS

Row	Generation	MW	Reference
Seller and Affiliate Capacity			
A	Installed Capacity	19,500	Workpaper.
B	Long-Term Firm Purchases	500	Workpaper.
C	Long-Term Firm Sales	−1,000	Workpaper.
D	Imported Power	0	Workpaper.
Non-Affiliate Capacity			
E	Installed Capacity	8,000	Workpaper.
F	Long-Term Firm Purchases	500	Workpaper.
G	Long-Term Firm Sales	−2,500	Workpaper.
H	Imported Power	3,500	Workpaper.
I	Balancing Authority Area Reserve Requirement	−2,160	Workpaper.
J	Amount of Line I Attributable to Seller, if any	−2,160	Workpaper.
K	Total Uncommitted Supply (SUM A,B,C,D,E,F,G,H,I,M)	9,840	
Load			
L	Balancing Authority Area Annual Peak Load	18,000	Workpaper.
M	Average Daily Peak Native Load in Peak Month	−16,500	Workpaper.
N	Amount of Line M Attributable to Seller, if any	−16,500	Workpaper.
O	Wholesale Load (SUM L,M)	1,500	
P	Net Uncommitted Supply (K–O)	8,340	
Q	Seller's Uncommitted Capacity (SUM A,B,C,D,J,N)	340	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P), (Fail if Line Q > Line P)	....	PASS.

Note: The following appendices will not be published in the *Code of Federal Regulations*.

Appendix C to Order No. 697–A

Required Provisions of the Market-Based Rate Tariff

Compliance With Commission Regulations

Seller shall comply with the provisions of 18 CFR part 35, Subpart H, as applicable, and with any conditions the Commission imposes in its orders concerning seller's market-based rate authority, including orders in which the Commission authorizes seller to engage in affiliate sales under this tariff or otherwise restricts or limits the seller's market-based rate authority. Failure to comply with the applicable provisions of 18 CFR part 35, Subpart H, and with any orders of the Commission concerning seller's market-based rate authority, will constitute a violation of this tariff.

Limitations and Exemptions Regarding Market-Based Rate Authority

[Seller should list all limitations (including markets where seller does not have market-based rate authority) on its market-based rate authority and any exemptions from or waivers granted of Commission regulations and include relevant cites to Commission orders].

Seller Category

Seller Category: Seller is a [insert Category 1 or Category 2] seller, as defined in 18 CFR 35.36(a).

Include All of the Following Provisions That Are Applicable

Mitigated Sales

Sales of energy and capacity are permissible under this tariff in all balancing authority areas where the Seller has been granted market-based rate authority. Sales of energy and capacity under this tariff are also permissible at the metered boundary between the Seller's mitigated balancing authority area and a balancing authority area where the Seller has been granted market-based rate authority provided: (i) Legal title of the power sold transfers at the metered boundary of the balancing authority area; (ii) the mitigated seller and its affiliates do not sell the same power back into the balancing authority area where the seller is mitigated. Seller must retain, for a period of five years from the date of the sale, all data and information related to the sale that demonstrates compliance with items (i) and (ii) above.

Ancillary Services

RTO/ISO Specific—Include All Services the Seller Is Offering

PJM: Seller offers regulation and frequency response service, energy imbalance service, and operating reserve service (which includes spinning, 10-minute, and 30-minute reserves) for sale into the market administered by PJM Interconnection, L.L.C. (''PJM'') and, where the PJM Open Access Transmission Tariff permits, the self-supply of these services to purchasers for a bilateral sale that is used to satisfy the ancillary services requirements of the PJM Office of Interconnection.

New York: Seller offers regulation and frequency response service, and operating reserve service (which include 10-minute non-synchronous, 30-minute operating reserves, 10-minute spinning reserves, and 10-minute non-spinning reserves) for sale to purchasers in the market administered by the New York Independent System Operator, Inc.

New England: Seller offers regulation and frequency response service (automatic generator control), operating reserve service (which includes 10-minute spinning reserve, 10-minute non-spinning reserve, and 30-minute operating reserve service) to purchasers within the markets administered by the ISO New England, Inc.

California: Seller offers regulation service, spinning reserve service, and non-spinning reserve service to the California Independent System Operator Corporation (''CAISO'') and to others that are self-supplying ancillary services to the CAISO.

Third Party Provider

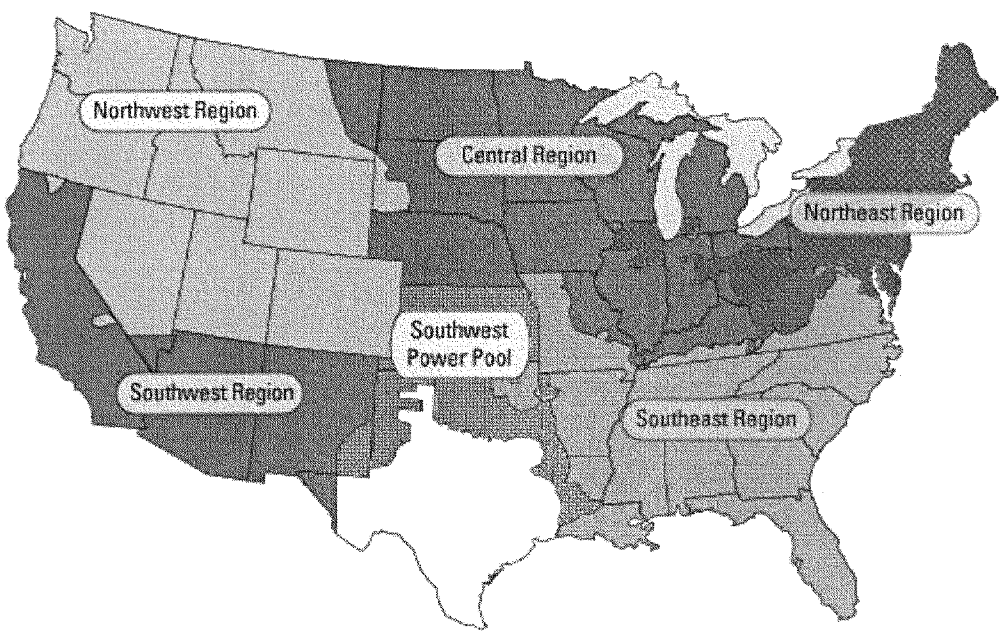
Third-party ancillary services: Seller offers [include all of the following that the seller is offering: Regulation Service, Energy Imbalance Service, Spinning Reserves, and Supplemental Reserves]. Sales will not include the following: (1) Sales to an RTO or an ISO, *i.e.*, where that entity has no ability to self-supply ancillary services but instead depends on third parties; (2) sales to a traditional, franchised public utility affiliated with the third-party supplier, or sales where the underlying transmission service is on the system of the public utility affiliated with the third-party supplier; and (3) sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers.

Appendix D to Order No. 697–A

Regions and Schedule for Regional Market Power Update Process

The six regions are combinations of NERC regions; RTOs and ISOs and are depicted in the map that follows.

Map of Geographic Regions



Northeast (ISO-NE, NYISO, PJM)

Southeast (NERC Regions SERC and FRCC (not including PJM or Midwest ISO))

Central (Midwest ISO, NERC Regions MRO and RFC (not including PJM))

Southwest Power Pool (NERC region SPP)

Southwest (California, NERC region WECC-AZNMSNV)

Northwest (NERC Regions WECC-NWPP and WECC-RMPA)

Appendix D–1

SCHEDULE FOR TRANSMISSION OWNING UTILITIES WITH MARKET-BASED RATE AUTHORITY AND THEIR AFFILIATES IN THE SAME REGION

Entities required to file	Filing period (anytime during the month)	Study period
Northeast Transmission Owners	December, 2007	Dec. 1, 2005–Nov. 30, 2006.
Southeast Transmission Owners	June, 2008	Dec. 1, 2005–Nov. 30, 2006.
Central Transmission Owners	December, 2008	Dec. 1, 2006–Nov. 30, 2007.
SPP Transmission Owners	June, 2009	Dec. 1, 2006–Nov. 30, 2007.
Southwest Transmission Owners	December, 2009	Dec. 1, 2007–Nov. 30, 2008.
Northwest Transmission Owners	June, 2010	Dec. 1, 2007–Nov. 30, 2008.
Northeast Transmission Owners	December, 2010	Dec. 1, 2008–Nov. 30, 2009.
Southeast Transmission Owners	June, 2011	Dec. 1, 2008–Nov. 30, 2009.
Central Transmission Owners	December, 2011	Dec. 1, 2009–Nov. 30, 2010.
SPP Transmission Owners	June, 2012	Dec. 1, 2009–Nov. 30, 2010.
Southwest Transmission Owners	December, 2012	Dec. 1, 2010–Nov. 30, 2011.
Northwest Transmission Owners	June, 2013	Dec. 1, 2010–Nov. 30, 2011.

Appendix D–2

SCHEDULE FOR ALL OTHER ENTITIES

Entities required to file	Filing period (anytime during the month)	Study period
All others in Northeast that did not file in December including all power marketers that sold in the Northeast.	June, 2008	Dec. 1, 2005–Nov. 30, 2006.
All others in Southeast that did not file in June including all power marketers that sold in the Southeast and have not already been found to be Category 1 sellers.	December, 2008	Dec. 1, 2005–Nov. 30, 2006.
All others in Central that did not file in December including all power marketers that sold in the Central and have not already been found to be Category 1 sellers.	June, 2009	Dec. 1, 2006–Nov. 30, 2007.
All others in SPP that did not file in June including all power marketers that sold in SPP and have not already been found to be Category 1 sellers.	December, 2009	Dec. 1, 2006–Nov. 30, 2007.
Others in Northeast that did not file in December and have not been found to be Category 1 sellers.	June, 2011	Dec. 1, 2008–Nov. 30, 2009.
Others in Southeast that did not file in June and have not been found to be Category 1 sellers.	December, 2011	Dec. 1, 2008–Nov. 30, 2009.
Others in Central that did not file in December and have not been found to be Category 1 sellers.	June, 2012	Dec. 1, 2009–Nov. 30, 2010.
Others in SPP that did not file in June and have not been found to be Category 1 sellers.	December, 2012	Dec. 1, 2009–Nov. 30, 2010.
Others in Southwest that did not file in December and have not been found to be Category 1 sellers.	June, 2013	Dec. 1, 2010–Nov. 30, 2011.
Others in Northwest that did not file in June and have not been found to be Category 1 sellers.	December, 2013	Dec. 1, 2010–Nov. 30, 2011.

Appendix E to Order No. 697–A

PETITIONER ACRONYMS

Abbreviation	Petitioner names
Ameren	Ameren Services Company.
APPA/TAPS	American Public Power Association/Transmission Access Policy Study Group.
Attorneys General of Connecticut and Illinois.	Richard Blumenthal, Attorney General for the State of Connecticut and the People of the State of Illinois, by and through the Illinois Attorney General Lisa Madigan.
Consumer Advocates	Attorneys General of New Mexico and Rhode Island, Colorado Office of Consumer Counsel, Utah Committee of Consumer Services, Public Utility Law Project of NY, and Public Citizen, Inc.
EEI	Edison Electric Institute.
El Paso E&P	El Paso E&P Company, L.P.
FirstEnergy	FirstEnergy Service Company.
FP&L	Florida Power & Light Company and FPL Energy, LLC.
Industrial Customers	Coalition of Midwest Transmission Customers, PJM Industrial Customer Coalition, NEPOOL Industrial Customer Coalition, Industrial Energy Users of Ohio, Industrial Energy Consumers of PA, Southeast Electricity Consumers Association, West Virginia Energy Users Group, and Southwest Industrial Customer Coalition.
LT Sellers	Long-Term Sellers.
MidAmerican	MidAmerican Energy Company and Cordova Energy Company LLC.
Montana Counsel	Montana Consumer Counsel.
Morgan Stanley	Morgan Stanley Capital Group Inc.
NASUCA	National Association of State Utility Consumer Advocates.

PETITIONER ACRONYMS—Continued

Abbreviation	Petitioner names
NREСA	National Rural Electric Cooperative Association.
NYISO	New York Independent System Operator, Inc.
NRG	NRG Energy, Inc.
Occidental	Occidental Power Marketing, L.P.
OG&E	Oklahoma Gas and Electric Company and OGE Energy Resources, Inc.
Pinnacle	Pinnacle West Companies.
PPM	PPM Energy, Inc.
PSEG Companies	Public Service Electric and Gas Company, PSEG Power LLC, and PSEG Energy Resources & Trade LLC.
Reliant	Reliant Energy, Inc.
Southern	Southern Company Services, Inc.
TDU Systems	Transmission Dependent Utilities Systems.
Wisconsin Electric	Wisconsin Electric Power Company.

UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 35

[Docket No. RM04–7–001; Order No. 697–A]

Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities

(Issued April 21, 2008)

KELLY, Commissioner, concurring:

Among other decisions in Order No. 697–A, the Commission has, on rehearing, determined that it will entertain applications that permit a mitigated seller to sell under a long-term contract at market-based rates. Specifically, we will allow a mitigated seller to demonstrate, on a case-by-case basis, that it does not have market power with respect to a specific long-term contract. I believe that if executed properly, allowing a mitigated seller the opportunity to demonstrate that, with respect to a specific contract, it does not have market power could be a useful and productive means for spurring competition and long-term contracting.

Ideally, I believe the Commission should apply an ordered, transparent and predictable test to each mitigated seller's application. Such a test should include an examination of barriers to entry, structural or otherwise. New entrants bring new capacity that, in theory at least, should exert downward pressure on prices. Our decision here hinges on the hypothesis that, absent barriers to new entrants, long-term markets may be presumed to be competitive. Ultimately, I would like to see the Commission confirm that hypothesis using the aforementioned test on a case-by-case basis.

Until such time as we have developed such a test, however, we have decided that the case-by-case approach described in this order allows the Commission to examine these applications with the appropriate rigor. The mitigated seller will have to show that a buyer under a long-term contract has viable alternatives, including the entry of third-party newly-constructed resources during the relevant future period as an alternative to purchasing under the contract at issue. I would prefer that mitigated sellers, in their applications, include an identified buyer. I believe the presence of an identified buyer will ensure that any assessment of the application is confined to a set of circumstances specific to the transaction, thereby avoiding the potential for granting a more general market-based rate authority to a mitigated seller for a particular area and period of time. I do not believe that such an outcome would be helpful to or consistent with our goals of promoting competition.

As the Commission moves forward, I anticipate relying on the views and expertise of interested parties in developing a specific test to apply to each case.

For these reasons, I respectfully concur with this order.

Suedeen G. Kelly.

[FR Doc. E8–9073 Filed 5–6–08; 8:45 am]

BILLING CODE 6717–01–C