107 FERC ¶ 61,018
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Pat Wood, III, Chairman;
Nora Mead Brownell, and Joseph T. Kelliher.

AEP Power Marketing, Inc., AEP Service Corporation, CSW Power Marketing, Inc., CSW Energy Services, Inc., and Central and South West Services, Inc.	Docket Nos. ER96-2495-016, ER96-2495-017, ER97-4143-004, ER97-4143-005, ER97-1238-011, ER97-1238-012, ER98-2075-010, ER98-2075-011, ER98-542-006 and ER98-542-007
(Not consolidated)	
Entergy Services, Inc.	Docket Nos. ER91-569-018 and ER91-569-019
Southern Company Energy Marketing L.P.	Docket Nos. ER97-4166-010 and ER97-4166-011
Conference on Supply Margin Assessment	Docket No. PL02-8-000

ORDER ON REHEARING AND MODIFYING INTERIM GENERATION MARKET POWER ANALYSIS AND MITIGATION POLICY

(Issued April 14, 2004)

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Introduction

1. In an order issued on November 20, 2001,[1] the Commission announced a new generation market power test, the Supply Margin Assessment (SMA), to be applied to market-based rate applications on an interim basis pending a generic review of new methods for comprehensively analyzing market power. It also established mitigation measures applicable to entities that fail the interim generation market power test. In this order, the Commission grants rehearing of the SMA Order to the extent that we replace the SMA generation market power test and instead, adopt two "indicative screens" for assessing generation market power and modify the mitigation announced in the SMA Order. This order benefits customers by improving the assessment and mitigation of generation market power in wholesale markets and, thus, better ensuring that prices charged for jurisdictional sales are just and reasonable.

2. The generation market power screens adopted herein are for interim purposes only. Concurrently with this order, the Commission is issuing a notice establishing a generic rulemaking docket to initiate a comprehensive generic review of the appropriate analysis for granting market-based rate authority, addressing generation market power, transmission market power, other barriers to entry, and affiliate abuse and reciprocal dealing.[2] In the interim, the policies we adopt herein will apply to all pending and future market-based rate applications, including three-year market-based rate reviews.

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[1] AEP Power Marketing, Inc., et al., 97 FERC ¶ 61,219 (2001) (SMA Order).

[2] Market-Based Rates for Public Utilities, 107 FERC ¶ 61,019 (2004).

3. As discussed below, following issuance of the SMA Order, the parties to the proceedings addressed in that order, as well as a number of other entities, filed comments and/or requests for rehearing. Several filed motions to vacate or for a stay of the order. In a notice issued on December 20, 2001, the Commission deferred the date for implementation of the price mitigation for spot market energy sales (section II.E) and announced its intention to hold a technical conference open to all interested persons. The Commission subsequently instituted a proceeding, Docket No. PL02-8-000, Conference on Supply Margin Assessment Test, to provide an opportunity for all interested persons to submit comments. In an effort to address concerns raised by commenters regarding the SMA and the price mitigation measures contained in the SMA Order, the Commission asked staff to prepare a Staff Paper identifying possible modifications or alternatives to both the SMA and price mitigation measures, and to hold a technical conference on these issues. Interested persons were given an opportunity to submit written comments on the Staff Paper, participate in a two-day technical conference, and provide further comments following the technical conference.

4. Entities representing a cross-section of the electric utility industry filed written comments and/or participated in the technical conference. These entities addressed various aspects of the SMA and the alternative interim generation market power screens set forth in the Staff Paper, including whether a pivotal supplier analysis, market share analysis, or some other approach is preferable for purposes of the interim generation market power analysis; whether capacity being considered should be based on total installed capacity and/or uncommitted capacity (i.e., whether planned outages, operating reserves, native load commitments, etc. should be subtracted from installed capacity); whether sales into markets administered by an independent system operator (ISO) or regional transmission organization (RTO) with Commission-approved market monitoring and mitigation should be exempt from the interim generation market power analysis; how to account for transmission limitations; how to define the relevant geographic market; and what are appropriate mitigation measures for those that are found to have market power in generation.

5. In the course of examining possible changes to the SMA and related mitigation, we have attempted to balance the need for the Commission to be able to identify market-based rate applicants who have the potential to exercise generation market power (and to impose appropriate mitigation measures to address such market power) with the need to ensure that the analysis we adopt and the mitigation measures we design do not mistakenly attribute market power to those who do not have it, and thereby distort markets. To this end, the Commission has given careful consideration to the arguments raised on rehearing of the SMA Order and to the numerous comments submitted throughout these proceedings. As described below, we have decided to modify certain

aspects of our interim generation market power analysis (from what we announced in the SMA Order) and to replace the mitigation for spot market energy sales proposed in the order with other mitigation to address market power concerns.

6. This order is responsive to the comments filed and balances the needs described above by using several different market power analyses instead of just one; finding that these screens should be indicative and not definitive of the presence of generation market power (thus providing greater flexibility to both applicants and intervenors); providing significant flexibility to both applicants and intervenors to provide additional evidence as to whether the applicant has generation market power including historical sales of transmission data; and where market power is detected, providing flexibility as to what is the appropriate mitigation based on particular factual circumstances, rather than a one-size-fits-all approach. The Commission has also provided an extensive process for all interested parties to inform the Commission of their views. To wit, in addition to requests for rehearing and comments on the SMA Order, the Commission has solicited an additional three rounds of comments, held a two-day technical conference that featured a variety of presenters from very diverse viewpoints, and issued a Staff Paper that set forth a variety of positions and sought comments on specific questions staff was considering. The Commission specifically invited comments both on the Staff Paper as well as the technical conference.

I. Background

7. The SMA Order addressed the three-year market-based rate reviews submitted by AEP Power Marketing, Inc. (AEP Marketing), AEP Service Corporation (AEP Service), on behalf of the American Electric Power operating companies, CSW Power Marketing, Inc. (CSW Marketing), CSW Energy Services, Inc. (CSW ESI), and Central and South West Services, Inc. (CSW Services) (collectively, AEP); by Entergy Services, Inc., on behalf of the Entergy operating companies and their affiliates (collectively, Entergy); and by Southern Company Energy Marketing L.P. (SCEM) involving the Southern Company Operating Companies (Southern Companies).[3]

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[3] Entities with market-based rate authority are required to file an updated market analysis within three years of the date of issuance of the Commission's order granting market-based rate authority, and every three years thereafter. In order for an applicant to obtain or retain market-based rate authorization, the Commission considers, among other things, whether the applicant and its affiliates possess generation market power. At the time of filing, SCEM (now Mirant Americas Energy Marketing, LP (Mirant)), was affiliated with the Southern Company operating companies (Alabama Power Company,

(continued)

8. The Commission uses a four-part test to determine whether to grant a public utility market-based rate authority. Prior to the SMA Order, when determining whether to grant market-based rate authority to public utilities in the 1990s, the Commission employed the "hub-and-spoke" analysis to determine whether an individual entity and its affiliates have the ability to exercise generation market power (the first part of the four-part test). In a hub-and-spoke analysis, the applicant computes its market share of both installed and uncommitted generation capacity in its control area market and separately for each of the control area markets to which it is directly interconnected (first-tier markets). While the Commission did not employ a bright-line test, it looked to a benchmark for generation market power of whether a seller had a market share of 20 percent or less in each of the relevant markets.

9. The other three parts of the four-part test included in the Commission's review consider whether the applicant has transmission market power; whether the applicant can erect barriers to entry; and whether there is the potential for affiliate abuse and reciprocal dealing. In this order, we consider only the generation market power part of our analysis (of which the SMA was a measure).

10. In the SMA Order, the Commission concluded that because of significant structural changes and corporate realignments in the electric industry, our hub-and-spoke analysis no longer adequately protected customers against generation market power in all circumstances. We noted that while the hub-and-spoke analysis worked reasonably well when the markets were essentially vertical monopolies trading on the margin and retail loads were only partially exposed to the market, the markets have since changed and expanded. Accordingly, the Commission announced a new market power test (SMA) for measuring generation market power, to be applied to market-based rate applications on an interim basis pending a generic review of new analytical methods for analyzing market power. The Commission found that the SMA builds on and modifies the previous hub-and-spoke analysis in two ways. First, in determining the geographic market, the SMA takes into account transmission constraints, and thus, can more accurately determine what supply can reach the market to compete with the applicant.

Georgia Power Company, Gulf Power Company, Mississippi Power Company, and Savannah Electric and Power Company) (collectively, Southern Companies). Subsequently, Mirant spun-off from Southern Companies and is no longer affiliated with a traditional public utility. On that basis, and consistent with the Commission's right to require an entity with market-based rate authority to file an updated analysis at any time, we considered Mirant and Southern Companies separately in the SMA Order.

11. Second, in determining the size that triggers generation market power concerns, the SMA establishes a threshold based on whether an applicant is pivotal in the market, i.e., whether at least some of the applicant's capacity must be used to meet the market's peak demand. When an applicant is pivotal, it is in a position to demand a high price above competitive levels and be assured of selling at least some of its capacity. An applicant is considered pivotal if its capacity exceeds the market's surplus of capacity above peak demand – that is, the market's supply margin. Thus, an applicant fails the SMA if the amount of its capacity exceeds the market's supply margin. Effectively, the supply margin identifies whether the applicant is a must-run supplier needed to meet the annual peak day load in the control area. Thus, the supply margin is sensitive to the potential for the applicant to successfully withhold supplies in the market in order to raise prices. If an entity failed the SMA, the Commission established mitigation measures in the SMA Order. By contrast, under the hub-and-spoke method, an applicant would pass the test if its market share were less than 20 percent. The hub-and-spoke did not consider whether the applicant's capacity was pivotal.

A. Application of the SMA

12. As the Commission stated in the SMA Order, in applying the SMA in non-ISO/RTO markets, the Commission would first consider the control area market where the applicant is located. Next, it would consider the markets directly interconnected to the applicant's control area market (first-tier markets). An applicant would pass the SMA if it and its affiliates own or control through contract an amount of generation located in the relevant control area market which is less than the supply margin (generation in excess of load) in that control area market. Under the SMA, the supply margin would include the amount of generation that can be imported into the control area market from each first-tier market limited by the total transfer capability (TTC) of the transmission system (i.e., the lesser of uncommitted capacity or TTC).[4] Sellers and their affiliates would be assumed to not possess generation market power in any control area market where they pass the SMA.

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[4] The total amount of TTC was used in the SMA Order as a point of reference to establish the maximum amount of uncommitted supply that could be injected into the market. We used this upper limit even though this amount of generation could not be simultaneously imported into an applicant's control area. We stated that intervenors would be allowed to present arguments on a case-by-case basis that another factor limiting import capability was appropriate, if warranted by the facts.

13. The Commission stated that all sales, including bilateral sales, into an ISO or RTO market with Commission-approved market monitoring and mitigation were exempt from the SMA and, instead, would be governed by the specific thresholds and mitigation provisions approved for the particular market.

14. In the SMA Order, the Commission applied the SMA to AEP, Entergy, and Southern Companies, and determined that each of the companies had the ability to exercise market power within its control area market because their generation was needed to meet the market's annual peak day load. A similar analysis of the markets outside of the relevant company's control area market indicated that all three companies passed the SMA. As a result, the Commission imposed mitigation measures for AEP, Entergy and Southern Companies within their control area markets. As discussed above, we subsequently deferred the date for implementation of the price mitigation for spot market energy sales (section II.E).

B. Mitigation for Spot Energy Sales

15. The SMA Order stated that the primary tool for exercising generation market power is physical or economic withholding. To prevent physical withholding, applicants who failed the SMA were required to offer uncommitted capacity (i.e., generation in excess of each hourly projected peak load and minimum required operating reserves) for spot market sales in the relevant market. To prevent economic withholding, this uncommitted capacity was priced using a split-the-savings formula,[5] which was the traditional cost-based ratemaking technique used for spot market energy sales.

16. Among other things, a mitigated applicant (and any affiliate that trades in the relevant market) was required in the SMA Order to post on its company website the projected twenty-four hourly incremental (out-of-pocket) costs for energy offered for spot market sales in its control area or in control areas surrounded by the applicant's control area. The incremental cost data would be based on the economic dispatch of uncommitted generation resources available after all prior commitments were prescheduled.

[5] A seller's incremental cost (the out-of-pocket cost of producing an additional MW) is compared with a buyer's decremental cost (the cost of not producing the last MW). The average of the incremental and decremental costs is the split-the-savings rate.

17. We did not impose a cost-based rate for longer-term transactions. However, we required that a mitigated applicant offer and post on its company website a portfolio of longer-term products and prices available to entities within the applicant's control area market.

18. The SMA Order stated that the mitigation for economic withholding would only be effective if applicants accurately post their incremental costs. In order to ensure that these costs were not inflated, the SMA Order imposed spot energy purchase mitigation. In addition to requiring the posting of hourly incremental cost data, mitigated applicants were required to simultaneously post hourly decremental cost data for the following trading day. Applicants would be required to purchase only spot energy offered at a delivered price below the applicant's posted decremental price. All entities, both inside and outside the applicant's control area, could offer to supply this service.

C. Mitigation for Size of Pivotal Supplier

19. The Commission stated that while imposing cost-based rates mitigates an applicant's ability to raise prices, it does nothing to mitigate the core problem, which is the relative size of an applicant. In an effort to increase supply in the applicant's core market and thereby reduce the applicant's relative size, we required a modification to the practice of evaluating generation interconnection applications for unaffiliated entities. We determined that when a transmission provider performs a study pursuant to a request for interconnection (e.g., feasibility, system impact or facility study), an unaffiliated entity, such as a merchant plant, could request that the output of its proposed project be modeled for study purposes to serve load within the control area that it is located without having to formally designate a particular load or without having to be selected as a designated network resource at the time of the interconnection. These unaffiliated entities would be treated as if they were a competing network resource in meeting load and load growth. In addition, we required that applicants post on their websites optimum areas on their systems for locating prospective generating facilities.

D. Residual Transmission Market Power

20. In the SMA Order, the Commission noted that intervenors raised serious concerns about the integrity of the postings of Available Transmission Capacity (ATC) on Entergy's and Southern Companies' OASIS sites (e.g., allegations of zero posting of ATC, of favorable treatment for affiliates, and of posting inaccurate information).

21. In order to ensure that available competing supplies were deliverable, the Commission required that Entergy and Southern Companies employ an independent third

party to operate and administer their OASIS sites. The order noted that AEP was already in compliance with this requirement due to its meeting the Commission's merger condition.[6]

II. Requests for Rehearing and Notice Delaying Effective Date of Mitigation

22. On December 13, 2001, Edison Electric Institute (EEI) filed a motion to intervene out-of-time, a motion to vacate the order or, in the alternative, to stay the effect of the SMA Order, and a request that the Commission initiate a rulemaking on the matters at issue in these proceedings. On December 14, 2001, AEP, Entergy, and Southern Companies filed requests for rehearing of the SMA Order. AEP's pleading included a motion to extend or stay the compliance deadline and a request for expedited action. Entergy's pleading contained an emergency motion for extension of time or, in the alternative, a stay pending rehearing. Southern Companies' pleading also contained a request for expedited action and a request to stay the SMA Order pending rehearing.

23. Additional motions to intervene out-of-time, requests for rehearing, comments and protests were filed. A list of these persons is in Appendix A to this order.

24. In a Notice Delaying Effective Date of Mitigation and Announcing Technical Conference, issued on December 20, 2001, the Commission deferred the date by which companies must implement the mitigation for spot market energy sales set forth in section II.E of the SMA Order and announced its intention to hold a technical conference open to all interested persons.

III. Docket No. PL02-8-000

25. On August 23, 2002, the Commission issued a notice establishing a proceeding, Docket No. PL02-8-000, Conference on Supply Margin Assessment Test, to provide an opportunity for all interested persons to submit comments. In preparation for the technical conference, the Commission invited all interested persons to submit written comments regarding the SMA and related mitigation measures. Numerous persons submitted comments and they are listed in Appendix B to this order.

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[6] See American Electric Power Company and Central and South West Corporation, 91 FERC ¶ 61,208 at 61,747-48 (2000).

IV. Technical Conference

26. On December 19, 2003, the Commission issued a Notice of Technical Conference on Supply Margin Assessment Test and Alternatives (December 2003 Notice), which was published in the Federal Register, 68 Fed. Reg. 75,229 (2003). The December 2003 Notice included a Staff Paper that identified possible modifications or alternatives to both the SMA and price mitigation measures and invited all interested persons to submit written comments on the Staff Paper by January 6, 2004. A supplemental notice with the conference agenda was published in the Federal Register, 69 Fed. Reg. 2,591 (2004). The technical conference was held on January 13-14, 2004, after which the Commission provided interested persons an opportunity to file supplemental comments.

27. The persons that filed comments in response to the Staff Paper are listed in Appendix C. The persons that filed comments following the technical conference are listed in Appendix D.

V. Procedural Matters

28. A number of entities filed late motions to intervene in these proceedings. When late intervention is sought after the issuance of a dispositive order, the prejudice to other parties and burden upon the Commission of granting the late intervention may be substantial. Thus, movants bear a higher burden to demonstrate good cause for granting such late intervention.[7]

29. The Commission ordinarily does not permit late interventions after an order has been issued. Here, however, the circumstances are different and unusual. Over the course of these proceedings, the Commission has used these proceedings to address matters well beyond the filings of the original parties, and, in fact, has held a technical conference that was open to all interested persons nationwide, and not just the original parties, and provided an opportunity for all interested persons to submit comments regarding the SMA and related mitigation measures. Given the expansion of these proceedings beyond the original filings and original parties that were at issue and our express invitation to a broader universe than the original parties, given that these occurred after the time for intervening had long passed, and given their interests and the absence of

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[7] See, e.g., AES Warrior Run, Inc. v. Potomac Edison Co., 105 FERC ¶ 61,357 at P 12 (2003); Midwest Independent System Operator, Inc., 102 FERC ¶ 61,250 at P 7 (2003).

undue prejudice or delay, we will grant the untimely, unopposed motions to intervene filed in these proceedings.

VI. Analysis

A. Overall Plan for Analyzing Generation Market Power

30. We have heard and considered many approaches for determining whether an applicant has market power in generation and, if so, what is the appropriate mitigation. As discussed more fully below, the two most commented on aspects regarding our approach to analyzing generation market power are: (1) that we develop appropriate screens to be used as tools that are broadly applied and give an indication of market power, rather than a single test that the Commission considers to be definitive;[8] and (2) whether native load obligations should be considered in our analysis.

31. With respect to mitigation, the primary focus of most comments is that, to the extent an applicant is found to have market power, the applicant should have the ability to propose its own mitigation specifically tailored to the market power findings on a case-by-case basis. In other words, rather than mandate a one-size-fits-all mitigation, the Commission should allow variation depending upon the particular circumstances of the applicant.

32. Some commenters urge the Commission to retain the exemption from the generation market power analysis for sales into ISO/RTO markets with Commission-approved market monitoring and mitigation. They argue that ISO/RTO markets are carefully monitored, and the mitigation processes and measures that are in place are specifically designed to keep any potential abuse of market power in check.

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[8] Dr. Joe Pace, Rodney Frame, and Dr. Craig Roach (who appeared on behalf of AEP, Southern, and Boston Pacific Company respectively) all commented in support of this approach at the technical conference. In its request for rehearing, Entergy argues that the SMA (or any market power test) should operate only as an indicator, not a definitive test, as has been the Commission's approach in merger proceedings. At the very least, Entergy states, utilities should be afforded the opportunity to demonstrate that the automatic application of the SMA would "work an injustice." Southern also argues that the SMA should not be used as a final determinative indicator of market power, but instead should be used as a preliminary test that indicates when market power concerns might be present.

33. Other commenters argue that an exemption for ISOs/RTOs with Commission-approved market monitoring and mitigation is not warranted because market rules designed for these markets are not flawless and market monitoring is an after-the-fact remedy. They argue that the Commission's goals should be to adopt one or more ex ante tests to avoid market power.

34. Addressed in many comments is whether the Commission should exempt small independent power producers and power marketers from the generation market power analysis. Commenters such as APPA state that power marketers and generators who have sold the entirety of their capacity and all rights to dispatch should qualify for a safe harbor involving minimal filing requirements.

35. Because of the breadth of the issues addressed in the comments filed in this proceeding, we have faced the very difficult task of determining how best to reach a balanced approach that takes into account the concerns of all industry participants (often conflicting) and at the same time, ensures that the Commission meets its responsibilities under the Federal Power Act (FPA) to ensure that wholesale rates remain just and reasonable.[9] We have concluded that an approach which balances regulatory certainty with appropriate flexibility for those seeking to obtain or retain market-based rate authority provides all industry participants with a regulatory process that meets our responsibilities under the FPA and allows market participants to bring case-specific factors to our attention in a timely manner. Accordingly, we adopt a policy that provides applicants a number of procedural options, several types of generation market power screens, and the option of proposing mitigation tailored to the particular circumstances of the applicant.

36. From the many viewpoints and interests that have been expressed, it has become increasingly clear that a single definitive test is not an optimal approach to measuring generation market power. Accordingly, we will adopt two "indicative" screens (or

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[9] Throughout the course of this proceeding, we have received numerous comments, suggestions, and criticisms from all sectors of the electric utility industry concerning possible modifications to the generation market power analysis and related mitigation proposed in the SMA Order. As discussed below, many of the modifications that we propose herein are responsive to suggestions proposed by commenters. In so doing, we have attempted to provide an accurate, albeit not necessarily exhaustive, description of the types of arguments raised in the comments. We have carefully considered all such comments in the course of reaching the various determinations we make herein.

analyses) for assessing generation market power, each with its own specific focus and attributes. We will adopt a pivotal supplier analysis based on the control area's annual peak demand and a market share analysis applied on a seasonal basis. Further, both the pivotal supplier analysis and market share analysis will consider native load obligations, and other commitments of the applicant.

37. If an applicant passes both screens, there will be a rebuttable presumption that the applicant does not possess market power in generation. However, we will allow intervenors to present evidence to rebut the presumption under these circumstances. For example, intervenors could present evidence based on historical wholesale sales data and/or challenge our assumption that competing suppliers inside a control area have access to the market (such a challenge could take into account both the actual historical transmission usage at the time of the study as well as the amount of available transmission capacity at that time). On the other hand, if an applicant fails either screen, this will create a rebuttable presumption that market power exists in generation.[10] In this instance, the applicant may then present evidence to rebut the presumption of market power by: (1) proposing a more robust market power study (the Delivered Price Test)[11]; (2) filing a mitigation proposal tailored to its particular circumstances that would eliminate the ability to exercise market power; and/or (3) informing the Commission that it will adopt the default cost-based rates discussed herein or proposing other cost-based rates and submit cost support for such rates. Before the Commission considers the Delivered Price Test, the applicant must be found to have "failed" one of the two "indicative" screens or so concede.[12] Accordingly, the Delivered Price Test will be considered as an alternative study to support the grant of market-based rate authority. In

[10] Such an applicant's rates prospectively will be made subject to refund until a final determination of market power is made or the applicant accepts a presumption of market power and so mitigates.

[11] As discussed below, we will also allow such applicants to present evidence, based on historical wholesale sales data, in support of a contention that, notwithstanding the results of the two indicative screens, they do not possess market power. However, the only additional market power study we will allow an applicant to file is the Delivered Price Test.

[12] Cf. New England Power Co., 82 FERC ¶ 61,179, at 61,662 (1998) (denying request to use alternate test unless applicant is unable to pass primary test); New York State Elec. & Gas Corp., 78 FERC ¶ 61,309, at 62,329 n.7 (1997) (discussing circumstances in which submission of alternate analysis will be considered).

all cases, the applicant or intervenors may present evidence such as historical wholesale sales data to support whether the applicant does or does not possess market power.

38. Where appropriate, the screens allow the applicant to submit streamlined applications or to forego the generation market power analysis entirely and, in the alternative, go directly to mitigation. For example, if an applicant would pass the screens without considering competing supplies from adjacent control areas, the applicant need not include such imports in its studies. We also remind applicants that section 35.27 of the Commission's regulations states that "any public utility seeking authorization to engage in sales for resale of electric energy at market-based rates shall not be required to demonstrate any lack of market power in generation with respect to sales from capacity for which construction has commenced on or after July 9, 1996."[13] Applicants meeting the criteria of section 35.27 of our regulations, as clarified in LG&E Capital,[14] may provide evidence demonstrating that they satisfy our regulations rather than submitting a generation market power analysis. However, if an applicant sites generation in an area where it or its affiliates own or control other generation assets, the applicant must address whether its new capacity, when added to existing capacity, raises generation market power concerns.

39. In addition, an applicant may forego submitting a generation market power analysis and accept a presumption of market power and go directly to mitigation by proposing case-specific mitigation that eliminates the ability to exercise market power, or agreeing to the default rates discussed below. Under such circumstances there will be a presumption of market power in all of the default relevant markets.

40. If an applicant's proposed mitigation does not eliminate its ability to exercise market power, then the applicant's market-based rate authority will be revoked in geographic areas where market power is found, and the applicant will be subject to cost-based default rates or other cost-based rates that the applicant proposes and the Commission approves. The Commission does not believe it has the legal basis to approve market-based rates if the applicant has not mitigated market power. Our default rates will be: (1) sales of power of one week or less must be priced at the applicant's incremental cost plus a 10 percent adder; (2) sales of power of more than one week but less than one year must be priced at an embedded cost "up to" rate reflecting the costs of

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[13] 18 C.F.R. § 35.27 (2003).

[14] LG&E Capital Trimble County LLC, 98 FERC ¶ 61,261 (2002) (LG&E Capital).

the unit or units expected to provide the service; and (3) new contracts for sales of power for more than one year must be priced at a rate not to exceed embedded cost of service and the contract must be filed with the Commission for review. Mitigated applicants must first receive Commission approval for each long-term power sale prior to transacting.[15]

41. Finally, as discussed below, we will grant rehearing with respect to the exemption from the generation market power analysis for sales into an ISO or RTO with Commission-approved market monitoring and mitigation, and require all applicants for market-based rate authority to submit the generation market power analysis adopted herein. However, similar to our approach under the hub-and-spoke analysis, when performing the generation market power analysis, applicants located in ISOs/RTOs with sufficient market structure may consider the geographic region under the control of the ISO/RTO as the relevant default geographic region for purposes of completing their analyses. To date, such ISOs/RTOs include PJM, ISO NE, NYISO and CAISO.

B. Generation Market Power Analysis

1. Rehearing/Intervention Comments

42. On rehearing, the majority of commenters, both supporters and opponents of the SMA, express concerns and request various modifications. Several commenters argue that the main flaw in the SMA is the way in which it measures suppliers' capacity and market capacity.[16] A number of commenters object to the SMA's focus on an applicant's total installed generation capacity, which includes an applicant's committed capacity. They argue that such an approach assumes that all of the applicant's capacity is available to the wholesale market and, accordingly, overstates the amount of an applicant's capacity, which in turn overstates the applicant's market power potential.[17] Some

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[15] We note here that, to the extent a party believes market power is being exerted in the course of negotiating a long-term purchase, such party may file a complaint pursuant to section 206 of the FPA.

[16] See, e.g., Request for Rehearing of AEP at 22-23, Entergy at 24, Southern at 8, EPSA at 8; EEI's January 2002 Comments at 7.

[17] See, e.g., Request for Rehearing of Alabama Commission at P 3, Allegheny at 4, Duke Power at 5, Entergy at 22-23; EEI's January 2002 Comments at 5, 8.

commenters argue that certain applicants with native load obligations may actually be net buyers at various times and not have an incentive to exercise market power.

43. Some commenters contend that utilities with a regulatory obligation to serve retail customers in their service territories at fixed or regulated rates and with long-term contractual obligations to provide wholesale service to entities in their control area cannot withhold substantial amounts of generation and, therefore, cannot drive up prices.[18] The Louisiana Commission claims that because the SMA fails to take into account a utility's obligation to serve retail load, the SMA penalizes retail ratepayers because the incumbent utility has sufficient capacity available to serve load.[19]

44. Commenters also argue that the SMA uses inconsistent measures of generation capacity by using a total capacity measure for sources that are within a relevant control area market versus an uncommitted capacity measure for first-tier utilities to calculate the amount of power that can be imported.[20]

45. Another major concern of commenters is that any generation market power analysis the Commission adopts should operate only as an "indicative screen" rather than a "definitive test" that bars companies from having market-based rate authority if they fail.[21] Entergy in particular argues that public utilities should be afforded an opportunity to demonstrate that adverse results of the SMA are misplaced when applied to their specific circumstances. Other commenters agree, stating that if an applicant fails the SMA, the Commission should conduct a more detailed examination to determine whether additional measures are necessary to prevent the potential exercise of market power.[22]

[18] See, e.g., Request for Rehearing of AEP at 24-25, Entergy at 25-26, Southern Companies at 8-10, Duke Power at 4-5.

[19] See Request for Rehearing of Louisiana Commission at 8.

[20] See, e.g., Request for Rehearing of Duke Power at 4-6, FirstEnergy at 7, AEP at 23, San Francisco at 6-9; EEI's January 2002 Comments at 8.

[21] See, e.g., Request for Rehearing of AEP at 29-31, Duke Power at 6-7, Entergy at 22; EEI's January 2002 Comments at 8.

[22] See, e.g., Request for Rehearing of Duke Power at 6, Entergy at 22.

46. Commenters further argue that the SMA Order oversimplifies the calculation of the actual import capability that is available by relying on TTC.[23] EEI argues that if the Commission continues with an SMA-style analysis, the measure of imported generation capacity should be capped by the simultaneous transfer limits into the control area.

47. The commenters also seek rehearing of other aspects of the SMA Order. The National Rural Electric Cooperative Association (NRECA) argues that the SMA Order fails to accurately define the relevant geographic market because it takes transmission constraints into account only after defining the relevant geographic market. PacifiCorp states that the Commission erred in proposing to apply the SMA and mitigation measures without examining the appropriateness of the measures, which have the potential to cause market distortions in the Western System Coordinating Council (WSCC).[24] The Florida Public Service Commission (Florida Commission) requests clarification of the measurement of "peak demand" to avoid a variable standard that changes annually.

2. PL02-8-000 October 2002 Comments

48. In the October 2002 comments, commenters reiterate most of the arguments and recommendations made in the requests for rehearing. Many commenters continue to argue that the SMA should be an indicative, not a definitive, test.[25] Numerous commenters again argue that the SMA overstates an applicant's generation capacity available to the wholesale market, and urge the Commission to consider only uncommitted capacity when measuring an applicant's available generating capacity.[26] Furthermore, commenters continue to argue that the SMA subjects an applicant to

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[23] See, e.g., Request for Rehearing of NRECA at 10 (arguing that the use of TTC to measure transmission import capability may simplify the SMA, but makes the test less meaningful), Allegheny at 7.

[24] The Western System Coordinating Council is now known as the Western Electricity Coordinating Council.

[25] See, e.g., October 2002 Comments of Duke at 4, EEI at 13, Entergy Attachment at 22, Exelon Attachment at 13-14, LG&E at 7-8, Mississippi Public Service Commission (Mississippi Commission) at 5-6.

[26] See, e.g., October 2002 Comments of AEP at 3-4, CP&L at 5, EEI at 10-11, EPSA, Exelon at 2, Louisiana Commission at 4-5, Southern Companies at 8-9, Duke at 3, Entergy at 4, FirstEnergy at 7-12, Williams at 4, Xcel at 3.

inconsistent treatment because an applicant's committed capacity in the relevant market is considered whereas only uncommitted capacity is considered for suppliers outside the relevant control area.[27] Some commenters recommend modifying the SMA to exclude additional generation required for operating reserves and planned outages.[28]

49. As on rehearing, commenters argue that the SMA overstates the import capability available to a particular control area because it counts the full amount of TTC as potential supply without considering simultaneous import constraints or other factors.[29] They argue that the Commission should modify the SMA to incorporate alternate methods of assessing a control area market's available total supply such as: (1) incorporating simultaneous transfer limits;[30] (2) considering the portion of transmission capacity reserved by the control area operator or host utility;[31] and (3) applying the SMA to locally-constrained areas where only limited supply outside of the local area can be used to meet local need.[32]

50. As on rehearing, some commenters argue that the SMA fails to accurately define a relevant geographic market.[33] They argue that it should not be based on the engineering construct of a control area, but instead should first use transmission constraints to define the area.

[27] See, e.g., October 2002 Comments of Duke at 3, 7, CP&L at 6, Exelon Attachment at 6.

[28] See, e.g., October 2002 Comments of APPA at 23, CAISO at 3, Exelon Attachment at 12, SMUD at 13, Southern Companies at 4.

[29] See, e.g., October 2002 Comments of Exelon at 10-11, NRECA Attachment A at 10, SMUD at 11-12, Southern Companies Attachment at P 15.

[30] See, e.g., October 2002 Comments of Exelon at 26, EEI.

[31] See, e.g., October 2002 Comments of Exelon at 24-25.

[32] See, e.g., October 2002 Comments of SMUD at 11-12.

[33] See, e.g., October 2002 Comments of EPSA at 7, NRECA Attachment A at 9, APPA/TAPS at 17-20.

51. Commenters also argue that the SMA Order ignores the possibility of collusion among generators in a particular market and suggest various methods for eliminating this possibility. APPA recommends adopting an incremental capacity Herfindahl-Hirschman Index (HHI) and a pivotal-supplier HHI. The California Public Utilities Commission (California Commission) recommends using a "real-time" test with thresholds that are low enough to discourage market power abuse as it occurs. The CAISO proposes the Residual Supply Index (RSI) to consider strategic bidding of other large suppliers.[34] Old Dominion suggests a Market Simulation Analysis model, which would be used in addition to the SMA, to more closely track market participants' behavior.

52. Commenters argue that the Commission should augment the SMA with other market power indicators. According to Southern Companies, no single screen will in every instance correctly predict whether an applicant has the potential to exercise market power. Southern Companies asserts that with any single measuring tool there is always the potential for inaccurate readings.[35] According to Entergy, even though the SMA does identify situations where shortages occur and the potential to exercise market power exists, the SMA does not address whether an applicant's share of the market also gives it an ability to exercise market power. Therefore, Entergy suggests the Commission use another indicator in conjunction with the SMA screen to determine whether the supplier is dominant in the market.[36]

53. The Electric Power Supply Association (EPSA) argues that the theory behind the SMA is that a seller whose market share exceeds the excess supply in the market can withhold output and raise prices. However, EPSA argues the theory has several key conditions that must be met, none of which are present in the SMA as proposed. EPSA states that before anything can be measured, the market must be defined (i.e., product and geography); a seller would not withhold output to raise prices unless it can enforce the price increase (i.e., entry would not defeat its price increase); and it would be arbitrary and capricious to base governmental policy on something that is unlikely to occur (i.e., a seller would not raise prices if it had to withhold so much of its output that its profit from sales from the remaining capacity would not exceed its lost opportunity of selling all of its capacity at competitive prices).

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[34] The RSI determines if a supplier is pivotal during a specified set of hours or all hours, i.e., without the applicant's supply the market demand cannot be met.

[35] See October 2002 Comments of Southern Companies at 24.

[36] See, e.g., October 2002 Comments of Entergy at 3-4 and Appendix A at 3-5.

54. EPSA also argues that the Commission should focus on the existence of market power for a sustained time period rather than peak demand because peak demand is transitory and may be very short. EPSA states that given the ever-changing electric landscape, the Commission should not rely on tests that evaluate market power at only a particular point in time.[37] Likewise, SMUD argues that the Commission should look at factors such as extreme weather, unanticipated forced outages or conditions affecting hydroelectric generation, unexpected demand growth, and new market conditions apart from market assumptions initially used in a supplier's SMA.

3. Staff Paper Proposal

55. In the Staff Paper included in the December 2003 Notice, staff identified two general methodologies for assessing generation market power that would constitute modifications to the interim SMA: Pivotal Supplier and Market Share. Among the improvements staff recommended were that the interim screens should recognize planned generation outages and periods other than the annual peak day load.

56. Staff recommended the use of State and Regional Reliability Council operating requirements for reliability (i.e., operating reserves) when calculating capacity amounts. Although staff continued to propose the use of TTCs as a proxy for transmission limitations between control areas, it sought comments on viable alternatives (e.g., historical firm transactions, losses, and simultaneous import capability). In addition, the Staff Paper proposed to measure generation market power on a monthly basis.

57. The Staff Paper also identified three alternative models to the SMA proposed by commenters – Reliant's Supply Duration Index,[38] CAISO's Residual Supplier Index,[39] and Old Dominion's Market Simulation Analysis.[40]

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[37] See October 2002 Comments of EPSA at 10.

[38] See October 2002 Comments of Reliant at 5-8.

[39] See October 2002 Comments of CAISO at 13-18.

[40] See October 2002 Comments of Old Dominion at 8-10.

4. Comments on Staff Paper

58. Comments on the Staff Paper were filed generally supporting both the Pivotal Supplier and Market Share Screens proposed by Staff, but with modifications.[41] Many commenters continue to argue that the generation market power analysis should only be used as an "indicative" screen to determine which utilities can be deemed to not have market power.[42] These commenters maintain that to the extent a utility fails the initial screens, there should be an opportunity to look more closely at the utility to determine whether it in fact has generation market power.[43] The commenters suggest that this "second-look" could involve either a pre-determined more comprehensive analysis or an analysis determined on a case-by-case basis tailored to the specific facts of the utility.[44] As in the prior rounds of comments, many commenters argue that the Commission should recognize retail native load and contractual obligations.[45]

59. With respect to the relevant geographic market, some commenters argue that the Commission should apply the generation market power analysis to a larger geographic market than a control area.[46] Others have commented that due to transmission constraints, RTO and ISO boundaries markets can also be smaller than a particular control area.[47]

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[41] See, e.g., January 2004 Comments of APPA/TAPS at 2-4, Dominion at 4-5, Duke Energy at 3-4, ELCON at 4-5, NRECA at 9-13, PacifiCorp at 8-18, Southern Companies at 11-15, Xcel at 5-8.

[42] See, e.g., January 2004 Comments of Duke at 3-4, Entergy Appendix at 4, Exelon at P 3; February 2004 Comments of EEI at 6.

[43] See, e.g., January 2004 Comments of Cinergy Appendix at 6, Southern Companies at 18 (Affidavit of Frame at P 46-47).

[44] See, e.g., January 2004 Comments of Duke at 4.

[45] See, e.g., January 2004 Comments of Alliant at 1-4, AEP at 2, Carnegie Mellon at 2, Cinergy Appendix at 2-4, Dominion at 4-5, Entergy Attachment at 3, Exelon at P 3, Louisiana Commission at 4-5, Southern Companies at 12-14 (Affidavit of Frame at P 30).

[46] See, e.g., January 2004 Comments of Cinergy Appendix at 4-6, Seminole at 8-9.

[47] See January 2004 Comments of APPA at 3.

60. Although several commenters support the use of TTC as a proxy for transmission limitations between control area markets, a number of others support the use of a different measure. Southern Companies asserts that it would be desirable for TTC values to be adjusted to reflect that the level of imports into at least some control areas that is achievable on a simultaneous basis is likely to be less than that determined by summing TTC across the separate paths into the control area.[48] DMEC does not oppose the use of TTC but argues that the Capacity Benefit Margin assigned to load serving entities (LSEs) should not be included as part of the TTC being available for competing supplies.[49] Exelon states that the SMA should reflect simultaneous import constraints that may limit total imports to a level below the sum of the relevant TTCs.[50] Exelon further asserts that the SMA should take into account the portion of transmission capacity reserved by the control area operator or the host utility.[51] CEOB adds that the analysis should also consider regional and local load pockets.

5. Technical Conference Comments

61. In the course of the technical conference, as well as in the supplemental comments following the technical conference, commenters reiterate positions they have taken in prior comments in this proceeding. The two most fundamental concerns are that the Commission should treat any generation market power analysis as an "indicative" screen rather than a "definitive" test,[52] and that native load obligations should be considered.[53]

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[48] See January 2004 Comments of Southern Companies (Affidavit of Frame at P 40).

[49] See January 2004 Comments of DMEC at 3.

[50] See January 2004 Comments of Exelon at 3 (referencing October 2002 comments on same issue).

[51] Id.

[52] See, e.g., February 2004 Comments of AEP at 2-4, EEI at 21-22, Southern Companies at 3, Reliant at 5-6; Technical Conference: Southern Companies at Tr. 355-56 (Frame); AEP at Tr. 380-81 (Pace).

[53] See, e.g., February 2004 Comments of AEP at 3-8 (Further Comments of Pace), BPA at 6-7, Duke Energy at 2, Entergy at 17-18, 34, Exelon (Final Comments of Hieronymus), PacifiCorp at 2-3, Puget at 4-5, Southern Companies at 10-11, SCE at 1-2,

(continued)

62. A number of commenters propose multi-tiered frameworks for Commission review of generation market power. APPA proposes a framework that includes filing requirements calibrated for the market power potential of the applicants that include a Safe Harbor Application, an Abbreviated Application, and a Standard Application.[54] NRECA provides a Preliminary Blueprint for Addressing Generation Market Power Issues. Among other things, NRECA supports a combination of different screens to process market-based rate applications in the near-term.[55] AEP supports the adoption of several screens where they are alternatives for use by applicants in different situations.[56] Reliant also supports an SMA screen that is designed in a multi-tiered manner, such that an applicant with little or no ability to influence a region's prices should pass without having to provide an extensive amount of data.[57]

EEI, Wisconsin Public Service Corporation, WPS Power Development Inc., and WPS Energy Services Inc. (collectively, WPS Companies) at 3, ArkansasCommission at 3-5, Louisiana Commission at 2-3.

[54] February 2004 Comments of APPA at 5-9.

[55] February 2004 Comments of NRECA at 6-8. NRECA suggests that the Commission consider a screen process similar to a decision tree that exempts applicants whose market share falls below some pre-determined threshold. If the applicant's market share falls within a threshold range, the applicant would be subject to a straightforward test of the type already considered by the Commission. If an applicant's market share, along with other dimensions of its profile, suggest more intensive and complex market involvement, then the market power assessment scrutiny should increase commensurately.

[56] See February 2004 Comments of AEP (Further Comments of Dr. Pace at 8-9). Dr. Pace suggests that small market participants could be allowed to use an abbreviated screen analysis which looks only at whether they own or control less than 10 percent of the generation resources in a particular control area. Technical Conference Statement of Dr. Pace at 16-17.

[57] February 2004 Comments of Reliant at 6-7. Reliant suggests a simple installed capacity screen with a recommended threshold level of 15 percent. However, Reliant argues that a multiple-screen approach should not require an applicant to pass all screens prior to being granted market-based rate authority. Only failed applicants should pass on to the next level screen, which Reliant suggests should be more rigorous, such as its proposed SDI screen.

6. Commission Determination

63. As discussed above, the hub-and-spoke analysis worked reasonably well during the early stage of developing markets when utilities were transitioning from closely regulated activities with limited trading to wholesale competition with market-based rate pricing. Today, in contrast to the period when the hub-and-spoke was employed, wholesale markets have many more sellers of differing types (e.g., independent power producers, power marketers, affiliate generators.) As markets have expanded and developed, both the number and types of sellers have increased and the complexity of wholesale markets has increased. Accordingly, it is incumbent on this Commission to modify its approach to reflect the new realities of the industry. We can no longer rely on a generation market power analysis that does not examine more closely market power.

64. Accordingly, and after weighing the many comments by a numerous and diverse set of commenters actively participating in today's markets, we will modify our approach. As we have stated above, for the purpose of developing an interim generation market power analysis, it has become increasingly clear that a single definitive test is not an appropriate measure. We agree with the many commenters who have argued that no single screen will always correctly predict market power and that having multiple screens will provide a better picture of whether an applicant has market power. We also agree with the suggestion by many commenters that, if a Commission review indicates market power (i.e., the applicant fails one or both of the initial screens), we take a closer look at that applicant and require a more detailed analysis.

65. We have developed an interim approach that addresses both of these issues by constructing two indicative screens that will, by and large, pass those applicants that raise no generation market power concerns and can otherwise be considered for market-based rate authority. At the same time, applicants that do not pass the initial screens will be allowed to provide additional analysis for Commission consideration. Such an approach allows us to concentrate our efforts on applicants that may possess generation market power while screening out those applicants that do not pose such concerns.

66. We also agree with commenters such as NRECA that properly identifying the geographic markets and the number of competitors in those markets is an essential element to any generation market power analysis. Varying demand levels can cause any system to operate differently as load conditions vary, and transmission constraints can keep some competitors out of the market and make some markets geographically larger than others. Likewise, transmission limitations can create load pockets wherein a geographic market may be smaller than the control area. To address these concerns, we will require that simultaneous transmission import capability be taken into consideration, as discussed below, when conducting the pivotal supplier and market share screens that

we adopt herein. We will also allow, though not require, applicants and intervenors to provide supplemental evidence such as historical wholesale sales and historical transmission data, in their submissions.

67. As we have noted above, commenters have argued both for and against whether native load obligations should be reflected in the interim generation market power analysis. In this order, we recognize that not all generation is available all of the time to compete in wholesale markets and that some accounting for native load requirements is warranted here. However, wholesale and retail markets are not so easily separated such that a clear distinction can be made between generation serving native load and generation competing for wholesale load. To the contrary, commenters at the technical conference provided detailed explanations of how the same generation assets swing between serving native load requirements and competing in the wholesale markets.[58] Most utility generation units are not exclusively devoted to serving native load, or selling in wholesale markets.

68. In this order, we strike a careful balance between acknowledging native load requirements and developing generation market power screens that are sufficient to indicate the potential for generation market power in wholesale markets. In doing so, and consistent with the indicative nature of the interim generation market power screens we adopt, we have taken a reasoned approach with respect to accounting for native load requirements while also allowing the applicant the flexibility to provide a more detailed analysis and to introduce evidence such as historical wholesale sales, and historical transmission data.

69. Finally, while there will be no safe harbor exemption from the screens based on the applicant's size, we agree with commenters such as NRECA and APPA that urge us to adopt a streamlined analysis for relatively small applicants that are unlikely to raise issues of generation market power. In addition, we remind applicants that, pursuant to section 35.27 of our regulations, as clarified by the Commission in subsequent orders, utilities meeting the criteria of that section shall not be required to demonstrate a lack of market power in generation with respect to sales from capacity for which construction

[58] For example, when asked whether generation capacity that is used to meet native load is also the same capacity that is used to make wholesale sales, AEP's representative, Dr. Joe Pace responded, "Yes and no. It is the same body of resources, but obviously it's doing one or the other at a given time." Technical Conference at Tr. 23.

commenced on or after July 9, 1996.[59] However, if an applicant sites or acquires generation in an area where it or its affiliates own or control other generation assets, the applicant must address whether its new capacity, when added to existing capacity, raises generation market power concerns.

a) Indicative Screens

70. We have carefully considered the arguments raised by investor-owned utility commenters, state commissions, and others urging the Commission to treat its generation market power analysis as an "indicative" screen, not a "definitive" test. In its February 2004 comments, Southern Companies, in particular, reiterates that "[t]he SMA should not be used as a final determinative indicator of market power, but instead should be used as a preliminary screen that indicates when market power concerns might be present. Once the results of a screen are known for a particular entity, interested parties could present additional evidence that would be utilized in order to make a final determination of whether the entity posses market power."[60] Southern Companies continues, "Given the number of market rate applicants, it would be very burdensome on the industry and the Commission to undertake a detailed analysis of generation dominance in every proceeding. Instead, the Commission should establish a relatively straight-forward screen that can be applied using available information. If the applicant or another

[59] As the Commission stated in Order No. 888, however, this does not mean that we will ignore specific evidence presented by an intervenor that a seller requesting market-based rate authority for sales from capacity for which construction commenced on or after July 9, 1996 nevertheless possesses generation market power. If such evidence is presented, we will evaluate whether the evidence disproves the premise that the seller lacks generation market power with respect to its new capacity. 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 Fed. Reg. 21,540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 at 31,659 (1996), order on reh'g, Order No. 888-A, 62 Fed. Reg. 12,274 (March 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), 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, et al. v. FERC, 225 F.3d 667 (D.C. Cir. 2000), aff'd sub nom. New York v. FERC, 535 U.S. 1 (2002).

[60] See February 2004 Comments of Southern Companies at 3.

interested party is not satisfied with the outcome, that entity should be able to present additional information to the Commission."[61]

71. We agree with commenters on this issue and will replace the single definitive SMA generation market power test. Instead, we will adopt two "indicative" screens for assessing generation market power that will provide a rebuttable presumption of whether market power exists for a utility applying to obtain or retain market-based rate authority. We will adopt an uncommitted pivotal supplier analysis that will evaluate the potential of an applicant (including its affiliates) to exercise market power based on the control area market's annual peak demand. We will also adopt an uncommitted market share analysis that will seasonally evaluate the market share of the uncommitted capacity of an applicant and its affiliates.

72. We are using both a pivotal supplier and market share analysis because, taken together, they give a reasonable indication of whether an applicant has market power.[62] The pivotal supplier analysis focuses on the ability to exercise market power unilaterally. It essentially asks whether the market demand can be met absent the applicant during peak times. Thus, the pivotal supplier screen measures market power at peak times, and particularly in spot markets. If demand cannot be met without some contribution of supply by the applicant, the applicant is pivotal. In markets with very little demand elasticity, a pivotal supplier could extract significant monopoly rents during peak periods because customers have few, if any, alternatives. The uncommitted market share analysis indicates whether a supplier has a dominant position in the market, which is another indication of whether the supplier has unilateral market power and may indicate the presence of the ability to facilitate coordinated interaction with other sellers. The market share screen is also useful in measuring market power because it measures an applicant's size relative to others in the market. Thus, by using the two screens together, the Commission is able to measure market power both at peak and off-peak times, and the ability to exercise market power both unilaterally and in coordinated interaction with

[61] Id. at 9-10. See also February 2004 Comments of AEP, Attachment I at 8-9; Request for Rehearing of AEP at 29-31, Entergy at 22; January 2002 Comments of EEI at 8; Comments of Gary Ackerman of Western Power Trading Forum, Technical Conference Tr. at 167-68.

[62] Michael Wroblewski of the FTC recommended during the technical conference that the Commission should evaluate both unilateral and coordinated market power. Technical Conference Tr. at 146-47.

other sellers. Using two screens will give the Commission a more complete picture of an applicant's ability to exercise market power.

b) Relevant Geographic Area

73. We believe that the interim generation market power analysis should continue to be based on a control area market approach. Commenters have submitted no compelling evidence that our historical approach of evaluating market power on a control-area-by-control-area basis is inadequate or insufficient for the typical situation and, significantly, control areas generally have abundant, accurate and publicly available data. Accordingly, our default relevant geographic markets under both screens will be first, the control area market where the applicant is physically located,[63] and second, the markets directly interconnected to the applicant's control area market (first-tier control area markets).[64] In this default analysis, we will consider only those supplies that are located in the market being considered (relevant market) and those in first-tier markets to the relevant market. As discussed more fully below, supplies being imported from first-tier markets will be limited by simultaneous transmission import capability.

74. Control area means an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to: (1) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s); (2) maintain scheduled interchange with other control areas, within the limits of Good Utility Practice; (3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and (4) provide sufficient generating capacity to

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[63] For applications by sellers with no generation assets in the ground (such as power marketers) that are affiliated with generation asset owning utilities, we will continue to evaluate the affiliate generation owner's market power when evaluating whether to grant market-based rate authority for the power marketer.

[64] Where a generator is interconnecting to a non-affiliate owned transmission system, there is only one relevant market (i.e., the control area in which the generator is locating.) This has been our historic practice.

maintain operating reserves in accordance with Good Utility Practice.[65] It is the interconnection and coordination between control areas that provides a foundation for the Commission to analyze transmission limitations and other transfers of energy and provides a reasonable measure of the relevant geographic market under typical circumstances. Thus, for investor-owned utility applicants, we establish a rebuttable presumption that the applicant's control area, and each of its neighboring first-tier control areas, are each relevant geographic markets. This is the same approach we have taken both under the SMA and prior to that under the hub-and-spoke analysis.

75. However, because we recognize the arguments raised by commenters that defining the relevant geographic market on a control area-by-control area basis may not be appropriate in all circumstances, on a case-by-case basis, we will allow applicants and intervenors to present additional sensitivity runs as part of their market power studies to show that some other geographic market should be considered as the relevant market in a particular case.[66] For example, applicants or intervenors could present evidence that the relevant market is broader than a particular control area. Applicants and intervenors may also provide evidence that because of internal transmission limitations (e.g., load pockets) the relevant market (or markets) is smaller than the control area.

76. We believe this is a balanced approach because it provides certainty upfront that the Commission intends to rely on a control area market approach while at the same time giving applicants and intervenors the opportunity to argue that the facts of a particular case support the use of some other geographic area as the relevant market.

c) Transmission Limitations

77. In the course of this proceeding, numerous commenters have expressed support for adopting a more accurate measure of transmission import capability than TTC. For example, APPA/TAPS notes that "TTC in no way reflects transmission capacity actually

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[65] See NERC Manual (available at ftp://www.nerc.com/pub/sys/all_updl/oc/opman/CACriteria-Version2-0601.doc (visited April 13, 2004)).

[66] Such an approach takes into account the comments made by EPSA, NRECA, and APPA, among others, as well as the technical conference testimony of Dr. Joe Pace, representing AEP.

available to competing suppliers . . . ."[67] APPA/TAPS further states that we should examine other transmission data, such as transmission reliability margin (TRM), capacity benefit margin (CBM), transmission line relief (TLR), and other transmission curtailments, and the applicant's own reservations, for their effects on capacity.[68]

78. A number of investor-owned utility commenters, and others, have stated that reservations of capacity made for the applicant's use should be excluded because that amount of capacity would not be available to competitors as competing supply.[69] Southern states that, if simultaneous import capability is known, the total import amount should be adjusted to recognize this limitation.[70] In addition, AEP states "Simultaneous limits on transfer capability should be taken into account. To do otherwise is to ignore realistic constraints on import competition."[71] East Texas Cooperatives recommend that the market power screen consider only the simultaneous import capability into a market region.[72]

79. One of the most important factors in determining whether generation market power exists involves properly accounting for competing supplies. Under the hub-and-spoke analysis, all competing supplies in first-tier markets were assumed to be able to be imported into the relevant market. However, our assumption did not take into account the physical barriers to moving supplies.

80. In the SMA Order, we adopted TTC as the upper limit for transmission access between control areas. We explained that the use of TTC was a point of reference to establish the maximum amount of uncommitted supply, even though this amount of

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[67] See February 2004 Comments of APPA/TAPS at 26.

[68] Id. at 26-28.

[69] See, e.g., Technical Conference: Southern at Tr. 373-74 (Frame); AEP at Tr. 382-84 (Pace); February 2004 Comments of Southern Companies at 12, Exelon at Attachment A, Duke Energy at 5.

[70] See February 2004 Comments of Southern at 5.

[71] See, e.g., February 2004 Comments of AEP at 7.

[72] See February 2004 Comments of East Texas Cooperatives at 7-9; see also February 2004 Comments of Steel Producers at 5.

generation could not be simultaneously imported into an applicant's control area. Thus, we acknowledged that our approach did not necessarily address the simultaneous transmission import issue, but noted that intervenors could raise concerns regarding limits on import capability on a case-by-case basis.

81. Recognizing that the SMA used TTC as a simplifying assumption, numerous commenters have indicated that it is impossible for this amount of generation to be simultaneously imported into an applicant's control area. Accordingly, after careful consideration, we will replace the use of TTC with simultaneous import capability as the appropriate measure of the effect of transmission limitations on how much generation can be imported into the relevant geographic market.

82. Given the experience we have gained regarding market power issues and competitive markets in general, and in concert with our improved and more robust generation market power studies adopted herein, we find that a more realistic evaluation of transmission in general is warranted. Thus, rather than continuing to assume an unrealistically high degree of transmission access for competitors, we will adopt a more realistic measure for such import capability. We will require a transmission-providing applicant to conduct simultaneous transmission import capability studies for its home control area and each of its interconnected first-tier control areas. These studies will be used in the pivotal supplier screen and market share screen to approximate the transmission import capability.

83. Simultaneous import studies require a more comprehensive analysis than that which is based on TTCs. Total import capability studies have been described by NERC and used by PJM/ECAR/MAIN for analyzing the amount of wholesale power importable into a control area from exterior regions. In response to the August 14, 2003 blackout, the U.S.-Canada Joint Task Force on the August 2003 Blackout made a recommendation to "reduce scheduled transfers to a safe and prudent level until studies have been conducted to determine the maximum simultaneous transfer capability limits".[73]

84. A transmission providing utility seeking to obtain or retain market-based rate authority will be required to provide, as discussed more fully in the attached Appendix E, a simultaneous import capability study for its home control area. In addition, when

[73] Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations, April 2004 at 109 (available at https://reports.energy.gov/BlackoutFinal-Web.pdf).

centering the market study on the transmission providing utility's first-tier control area (i.e., markets), the transmission providing applicant should use the methodologies outlined in its Commission-approved OATT tariff, thereby making a reasonable approximation of simultaneous import capability that would have been available to suppliers in surrounding first-tier markets during each seasonal peak. The transfer capability should also include any other limits (such as stability, voltage, CBM, TRM) as defined in the tariff and that existed during each seasonal peak.[74] The "contingency" model should use the same assumptions used historically by the transmission provider in approximating its control area import capability (see Appendix E).

85. As discussed above, an applicant may provide a streamlined application to show that it passes our screens. Thus, with respect to simultaneous import capability, if an applicant can show that it passes our screens for each relevant geographic market without considering imports, no such simultaneous import analysis needs to be provided. Further, we recognize that certain applicants will not have the ability to perform a simultaneous import capability study. Accordingly, if an applicant demonstrates that it is unable to perform a simultaneous import study for the control area in which it is located, the applicant may propose to use a proxy amount for transmission limits. We will consider such proposals on a case-by-case basis.

86. As discussed above, we will consider credible evidence that some geographic market, other than our default relevant geographic market, should be considered as the relevant market in a particular case. To the extent we allow some other geographic market to be studied, the proponent of using that alternative market must adhere to including all monitored lines/constraints and critical contingencies that were historically

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[74] Power Plant Research Program, Maryland Department of Natural Resources, An Assessment of the Transmission Grid of Maryland Utilities and Some Potential Consequences of Retail Competition, "Transmission Planning Issues," at Section IV, p. IV-6 (January 1999) (describing "import capability") (available at http://www.esm.versar.com/pprp/features/transmiss/transmiss.htm); PJM, Import Capability Study Procedure Manual, at Sections 8.3.3-8.3.4, p. 7 (February 24, 2001) (describing methods used to calculate the PJM total import capability during emergency conditions) (available at http://www.maac-rc.org/reference/cap_study.pdf); ECAR and MAIN Joint Study, "Simultaneous Import Capability Into Illinois and Michigan," (July 7, 1998) (forming a joint study group at the request of the NERC Reliability Assessment Subcommittee, and studying both non-simultaneous and simultaneous transfer capabilities) (available at ftp://www.nerc.com/pub/sys/all_updl/docs/pubs/98multi.pdf).

applied during the seasonal peaks in assessing available transmission for non-affiliate transmission customers.

d) Reductions in Generation Attributed To Applicants, Including Native Load Obligations

87. At the technical conference, Dr. Joe Pace, appearing on behalf of AEP stated that "any market power screen that ignores the applicant's native load and long-term contract obligations is fatally flawed."[75] Bill Marshall of Southern Company stated: "The Commission must take into account firm obligations and focus only on the uncommitted capacity that can be used to make additional spot sales."[76]

88. We have carefully considered the arguments raised by numerous investor-owned utility commenters that the SMA overstated an applicant's generation capacity available to serve the wholesale market, and we agree with these commenters. Accordingly, both the pivotal supplier analysis and the market share analysis adopted herein recognize utilities' obligations to serve native load. At the same time, we also recognize the concerns voiced by other commenters who are concerned that removing all generation that is used at any time to serve native load will understate a utility's potential market power. Since utilities generally use the same generating units to make off-system wholesale sales and to serve native load,[77] and since the amount of generation needed to serve native load can vary from hour to hour, some reasonable proxy is needed to represent the amount of generation that is needed to serve native load. Accordingly, as discussed below, the pivotal supplier analysis, for both applicants and competing suppliers, will use the average of the daily native load peaks during the month in which the annual peak demand day occurs as a proxy for native load obligation. The market share analysis for both applicants and competing suppliers will use the native load obligation on the minimum peak demand day for a given season. In this regard, we have attempted to strike a balanced approach to determining what portion of a utility's generation capacity is generally available to serve the wholesale market.

89. We recognize that at times portions of applicants' and competing suppliers' capacity is not available to compete in wholesale markets. However, we also recognize

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[75] See Technical Conference Tr. at 8.

[76] See Technical Conference Tr. at 103.

[77] See, e.g., Technical Conference Tr. at 23-26.

that utilities control a portfolio of generation resources from which they serve native load and compete in wholesale markets. In Louisville Gas and Electric Co.,[78] we recognized that such a portfolio of resources is not readily separated into retail and wholesale bundles. We stated:

> A firm's share of the uncommitted capacity available in a market is a general indication of its ability to dominate firm sales in the short-run market. Because of the need to meet native and other firm load at the system peak, the capacity that a seller can commit to new firm sales for more than a year's duration is limited to that above the amount needed to meet this load.
>
> The capacity that a seller can offer for shorter-term firm sales and for nonfirm sales, however, is not limited to that above the amount needed to meet the annual peak load of native-load customers and other firm customers. When native load and other firm load is less than its annual peak, some additional capacity is freed up for shorter-term firm sales. Sellers can also use capacity freed up by load variations to make nonfirm sales because it can be quickly withdrawn if needed to meet firm commitments. Because of this, installed capacity is used as an additional market power measure; installed capacity is the maximum existing capacity actually available for all types of sales.[79]

90. Because the portion of capacity that would be solely dedicated to serve native load changes as market conditions change, we will adopt a conservative approach in determining a proxy for native load obligations under the market share screen, and a less conservative approach under the pivotal supplier screen. Our approach in this regard, when coupled with adopting "indicative" screens and allowing applicants to present a Delivered Price Test market power analysis if they fail an initial screen and allowing parties to present evidence such as historical sales data, balances concerns regarding native load obligations with our need to ensure that a supplier's generation presence in wholesale markets is accurately measured.

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[78] 62 FERC ¶ 61,016 (1993).

[79] Id. at 61,146. However, native load will never be zero and the amount of installed capacity actually available for firm and non-firm sales in the short-term bulk market will vary with existing native load variations.

91. As discussed more fully below, the pivotal supplier analysis is based on the peak hour of the year. Accordingly, the pivotal supplier analysis essentially determines which suppliers are available to serve demand (i.e., whether the competing suppliers have sufficient available capacity to meet demand) as the demand moves from peak period levels to the highest level at the hour of the annual peak demand (needle peak). Conditions in peak periods can provide significant opportunity to exercise market power. As capacity is utilized to meet demand there is less available to sell on the margin and often less competition. Only focusing on needle peaks that occur for a single hour and that are only known after the fact does not give an accurate reflection of the competitive dynamics of peak periods. As demand increases during peak periods, buyers and sellers are positioning themselves in the market with similar but incomplete information. Buyers are projecting their needs and trying to secure needed power, while sellers are negotiating to obtain the highest price for that power. With increasing demand, fewer units are available to serve anticipated peak needs and buyers bid to secure dwindling supply load increases. In addition, buyers must be prepared for the contingency that a unit will be forced out and they will need to purchase in a period of even greater scarcity. It is in these periods of relatively short supply that the greatest potential to exercise market power may exist. Accordingly, using the average daily peak native load for the peak month, rather than using the native load at the time of the needle peak, as a proxy for capacity committed and not otherwise available for wholesale transactions more accurately identifies whether a supplier may be pivotal in the peak period market.

92. With respect to the market share analysis, as discussed below, we will subtract the native load obligation on the minimum peak demand day, in a given season, from the capacity otherwise controlled by the applicant and competing suppliers. By subtracting the generation needed to serve native load on the minimum load day of the season, we identify all of the capacity that is available to compete in wholesale markets at some point during the season. In other words, the use of this proxy for native load reflects the fact that the rest of the applicant's generation was uncommitted and available at some point during that season to sell in wholesale markets. For the purpose of constructing a reasonably balanced conservative screen, we will consider all such available capacity for both applicants and competing suppliers.

93. Many investor-owned utilities and state commission commenters criticized the SMA because it treated all of an applicant's capacity as available to compete in wholesale markets, and did not provide reductions to reflect: (1) investor-owned utility generation used to provide operating reserves that are required by state commissions; (2) planned outages; and (3) long-term firm non-requirement sales. In particular, Rodney Frame of

Southern Company asserts that a technical defect of the SMA is that it did not account for planned outages.[80] Dr. Joe Pace, representing AEP, states that operating reserves for the relevant period should be accounted for when measuring uncommitted capacity.[81] We agree that some offsets to generation attributed to the applicant are appropriate and should be reflected in our new generation market power screens.

e) Pivotal Supplier Analysis Using Uncommitted Capacity

94. The first step in this analysis is to determine total supply in the relevant market. To do so, the analysis centers on and examines the control area market where the applicant's generation is physically located (relevant control area market).[82] Total supply is determined by adding the total amount of uncommitted capacity located in the relevant control area (including capacity owned by the applicant and competing suppliers) with that of uncommitted supplies that can be imported (limited by simultaneous transmission import capability) into the relevant control area from the first-tier markets.

95. 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 non-requirement sales. Uncommitted capacity from an applicant's remote generation (generation located in an adjoining control area) should be included in the applicant's total uncommitted capacity amounts. In contrast to the SMA, which only used uncommitted capacity for an applicant's competitors in adjoining control areas, our two new screens will use the uncommitted capacity of both the applicant and its competitors.[83] Any simultaneous transmission import capability should first be allocated to the applicant's uncommitted

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[80] See December 14, 2001 Comments of Southern Companies, Frame Aff. at 9.

[81] See February 2004 Comments of AEP at P 19.

[82] As noted above, there is a rebuttable presumption that the relevant geographic market for purposes of this analysis is the applicant's control area market as well as each of the applicant's first-tier markets.

[83] We note that commenters criticized the SMA for examining total capacity within the relevant control area market and uncommitted capacity in adjoining control areas. In particular, Entergy states "an uncommitted capacity measure should be used both for market participants located within a control area as well as those located outside of it." See December 14, 2001 Affidavit of Dr. Henderson at 6.

remote generation. Any remaining simultaneous transmission import capability would then be allocated to any uncommitted competing supplies.

96. Capacity reductions as a result of operating reserve requirements should be no higher than State and Regional Reliability Council operating requirements for reliability (i.e., operating reserves). Any proposed amounts that are higher than such requirements must be fully supported and will be considered on a case-by-case basis. Moreover, if an intervenor provides conclusive evidence that an applicant did not in actual practice comply with the NERC or regional reliability council operating reserve requirements, then we will take this into account in determining the amount of the operating reserve deduction. However, we emphasize that we expect each utility to meet its NERC and regional reliability council reserve requirements, and that absent a clear showing to the contrary by an intervenor, the required operating reserve requirement is what we will use as the deduction in the market-based rate calculation.

97. We do not expect that applicants will have planned generation outages scheduled for the annual peak load day. However, on a case-by-case basis, we will consider credible evidence that planned generation outages for the peak load day of the year should be included based on the particular circumstances of the applicant.[84]

98. After computing the total uncommitted supply available to serve the relevant market, the next step in this analysis involves identifying the wholesale market. The proxy for the wholesale load is the annual peak load (needle peak) less the proxy for native load obligation, as discussed above (i.e., the average of the daily native load peaks during the month in which the annual peak load day occurs). Peak load is the largest electric power requirement (based on net energy for load) during a specific period of time usually integrated over one clock hour and expressed in megawatts, for the native load and firm wholesale requirements sales.

99. To calculate the net uncommitted supply available to compete at wholesale, the pivotal supplier analysis deducts the wholesale load from the total uncommitted supply. If the applicant's uncommitted capacity is less than the net uncommitted supply, the applicant satisfies the pivotal supplier portion of the generation market power analysis and passes the screen. If the applicant's uncommitted capacity is equal to or greater than

[84] As noted below, the market share screen deducts generation capacity used for planned outages (that were done in accordance with good utility practice) in all four seasons in order to reflect the typical operation of generation units.

the net uncommitted supply, then the applicant fails the pivotal supplier analysis which creates a rebuttable presumption of market power.

f) Wholesale Market Share Analysis Using Uncommitted Capacity

100. The wholesale market share analysis measures for each of the four seasons whether an applicant has a dominant position in the market based on the number of megawatts of uncommitted capacity owned or controlled by the applicant as compared to the uncommitted capacity of the entire relevant market. We will use uncommitted capacity amounts, as defined in connection with the pivotal supplier analysis, with the following variations. First, the proxy for native load will be the minimum peak load day for each season considered.[85] Second, planned outages (that were done in accordance with good utility practice) for each season will be considered. Planned outage amounts should be consistent with those as reported in FERC Form No. 714. To determine the amount of planned outages for a given season, divide the total number of MW-days of outages by the total number of days in the season. For example, if 500 MW of generation that is out for six days during the winter period the calculation of planned outages would be: (500 MW X 6)/91 or 33 MW.

101. The market share analysis is designed to serve as a screen of whether a supplier has a dominant presence in the wholesale electricity market. It is designed to complement the pivotal supplier analysis in order to allow the Commission to readily identify those suppliers that do not have market power in wholesale electricity markets. For those utilities with market shares that raise generation market power concerns, other procedural options are available, including submitting a more rigorous market power analysis (i.e., the Delivered Price Test).

102. The market share analysis adopts an initial threshold of 20 percent. That is, a supplier who has less than a 20 percent market share in the relevant market for all seasons will be considered to satisfy the market share analysis.[86] An applicant with a market

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[85] The four seasons considered are: Summer (June/July/August); Fall (September/October/November); Winter (December/January/February); and Spring (March/April/May).

[86] The 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. P13,103 (CCH 1988): "The Department [of Justice] is likely to challenge any merger

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share of 20 percent or more in the relevant market for any season will have a rebuttable presumption of market power but can present historical evidence to show that the applicant satisfies our generation market power concerns.[87]

103. The market share analysis is designed to identify the possibility of generation market power. There is a substantial body of economic literature relating to the ability of a firm with a dominant position in a market to raise the market price above competitive levels. In the Dominant Firm and Competitive Fringe Model, the dominant firm behaves like a monopolist with respect to the demand that cannot be met by other competitors, sets a monopoly price on that "residual demand," and the other competitors then charge the same price for the remaining demand, resulting in a price above the competitive level.[88] In the Stackelberg Leader-Follower Model,[89] the leader is able to increase its profits by taking advantage of its first-mover advantage, and drive the market price above competitive levels.[90] In both of these models, the lower the demand elasticity, the higher

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satisfying the other conditions in which the acquired firm has a market share of 20 percent or more."

[87] The other evidence we will consider is historical sales and/or access to transmission to move supplies within, out of, and into a control area market.

[88] See, e.g., Robert Pindyck and Daniel Rubinfeld, Microeconomics 450-451 (5th ed. 2001) (Pindyck and Rubinfeld); Dennis W. Carlton and Jeffrey M. Perloff, Modern Industrial Organization 157-69 (2d ed. 1994).

[89] See Carlton and Perloff at 250-253; Pindyck and Rubinfeld at 436-437. In the Stackelberg model, the dominant firm is the "leader" in that it chooses how much to produce (or withhold) first, then the other firm or firms respond with a profit-maximizing output level based on the output decision of the leader. By choosing the output level first, the dominant firm is able to increase its profits by raising price above the competitive level.

[90] In addition, a large market share can also be indicative of the ability to coordinate with other suppliers. Carlton and Perloff argue that "[e]ven if there are many firms, the largest firms may meet and establish a cartel (dominant firm) that does not explicitly include the smaller fringe firms" (Carlton and Perloff at 186). Additionally, as noted by Michael Wroblewski at the SMA technical conference "market share screens are an improvement over the pivotal supplier in that they allow a look at coordinated interaction." Tr. 146-47. While a more thorough analysis of market concentration would be more informative about the likelihood of coordinated behavior, all else being equal, a

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the mark-up over marginal costs. It must be recognized that demand elasticity is extremely small in electricity markets; in other words, because electricity is considered an essential service, the demand for it is not very responsive to price increases. These models illustrate the need for a conservative approach in order to ensure competitive outcomes for customers because many customers lack one of the key protections against market power: demand response.

104. A seller that does not have a 20 percent market share in any season would be unlikely to hold a dominant position in the market. Our market share analysis would allow us to readily identify such suppliers. While a supplier with less than a 20 percent market share, in certain circumstances, can affect the market price during periods of limited supply alternatives, our pivotal supplier analysis addresses such situations by examining whether there are sufficient competing supply alternatives to meet the market's peak load.

g) Delivered Price Test

105. Applicants failing one or more of the initial screens will have a rebuttable presumption of market power. If such an applicant chooses not to proceed directly to mitigation, it must present a more thorough analysis using the Commission's Delivered Price Test. The Delivered Price Test is used to analyze the effect on competition for transfers of jurisdictional facilities in section 203 proceedings,[91] using the framework described in Appendix A of the Merger Policy Statement and revised in Order No. 642.[92] The Delivered Price Test is well established: it has been used routinely by the

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larger market share for the applicant can indicate a larger likelihood of coordinated behavior.

[91] 16 U.S.C. § 824b (2000).

[92] Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement, Order No. 592, 61 Fed. Reg. 68,595 (1996), FERC Stats. & Regs., Regulations Preambles July 1996-December 2000 ¶ 31,044 (1996), reconsideration denied, Order No. 592-A, 62 Fed. Reg. 33,341 (1997), 79 FERC ¶ 61,321 (1997) (Merger Policy Statement); see also Revised Filing Requirements Under Part 33 of the Commission's Regulations, Order No. 642, 65 Fed. Reg. 70,983 (2000), FERC Stats. & Regs., Regulations Preambles July 1996-December 2000 ¶ 31,111 (2000), order on reh'g, Order No. 642-A, 66 Fed. Reg. 16,121 (2001), 94 FERC ¶ 61,289 (2001).

Commission to analyze market power in the merger context for many years, and it has been affirmed by the courts.[93]

106. The Delivered Price Test defines the relevant market by identifying potential suppliers based on market prices, input costs, and transmission availability, and calculates each supplier's economic capacity and available economic capacity for each season/load condition.[94] The results of the Delivered Price Test can be used for pivotal supplier, market share and market concentration analyses. A detailed description of the mechanics of the Delivered Price Test is provided in Appendix F.

107. Using the economic capacity for each supplier, applicants should provide pivotal supplier, market share and market concentration analyses. Examining these three factors with the more robust output from the Delivered Price Test will allow applicants to present a more complete view of the competitive conditions and their positions in the relevant markets.

108. Under the Delivered Price Test, to determine whether an applicant is a pivotal supplier in each of the season/load conditions, applicants should compare the load in the destination market to the amount of competing supply (the sum of the economic capacities of the competing suppliers). The applicant 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. The analysis should also be performed using available economic capacity to account for applicants' and competing suppliers' native load commitments. In that case, native load in the relevant market would be subtracted from the load in each season/load period. The native load subtracted should be the average of the actual native load for each season/load condition.

109. Each supplier's market share is calculated based on economic capacity (the Delivered Price Test's analog to installed capacity). The market shares for each season/load condition reflect the costs of the applicant's and competing suppliers' generation, thus giving a more complete picture of the applicant's ability to exercise

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[93] See, e.g., Wabash Valley Power Associates, Inc. v. FERC, 268 F. 3d 1105 (D.C. Cir. 2001).

[94] Super-peak, peak, and off-peak, for Winter, Shoulder and Summer periods and an additional highest super-peak for the Summer.

market power in a given market. For example, in off-peak periods, the competitive price may be very low because the demand can be met using low-cost capacity. In that case, a high-cost peaking plant that would not be a viable competitor in the market would not be considered in the market share calculations, because it would not be counted as economic capacity in the Delivered Price Test. Applicants must also present an analysis using available economic capacity (the Delivered Price Test's analog to uncommitted capacity) and explain which measure more accurately captures conditions in the relevant market.

110. Under the Delivered Price Test, applicants must also calculate the market concentration using the Hirschman-Herfindahl Index (HHI) based on market shares.[95] HHIs are usually used in the context of assessing the impact of a merger or acquisition on competition. However, as noted by the U.S. Department of Justice in the context of designing an analysis for granting market-based pricing for oil pipelines, concentration measures can also be informative in assessing whether a supplier has market power in the relevant market. "The Department and the Commission staff have previously advocated an HHI threshold of 2,500, and it would be reasonable for the Commission to consider concentration in the relevant market below this level as sufficient to create a rebuttable presumption that a pipeline does not possess market power."[96]

111. A showing of an HHI less than 2500 in the relevant market for all season/load conditions for applicants that have also shown that they are not pivotal and do not possess more than a 20 percent market share in any of the season/load conditions would constitute a showing of a lack of market power, absent compelling contrary evidence from intervenors. Concentration statistics can indicate the likelihood of coordinated interaction in a market. All else being equal, the higher the HHI, the more firms can extract excess profits from the market. Likewise a low HHI can indicate a lower likelihood of coordinated interaction among suppliers and could be used to support a claim of a lack of market power by an applicant that is pivotal or does have a 20 percent or greater market share in some or all season/load conditions. For example, an applicant

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[95] The HHI is the sum of the squared market shares. For example, in a market with five equal size firms, each would have a 20 percent market share. For that market, HHI = $(20)^2 + (20)^2 + (20)^2 + (20)^2 + (20)^2$ = 400 + 400 + 400 + 400 + 400 = 2000.

[96] See Comments of the United States Department of Justice in response to Notice of Inquiry Regarding Market-Based Ratemaking for Oil Pipelines, Docket No. RM94-1-000 (January 18, 1994).

with a market share greater than 20 percent could argue that that it would be unlikely to possess market power in an unconcentrated market (HHI less than 1000).

112. As with our initial screens, applicants and intervenors may present evidence such as historical wholesale sales. Those data could be used to calculate market shares and market concentration and could be used to refute or support the results of the Delivered Price Test. We encourage applicants to present the most complete analysis of competitive conditions in the market as the data allow. We have used actual data in our analysis of mergers and other section 203 jurisdictional transactions to supplement or support the analysis of the effect of such transactions on competition. As we stated in Order No. 642:

> If sales data indicate that certain participants actually have been able to reach the market in the past, it is appropriate to consider whether they are likely candidates to be included in the market in the future. It is for this reason that we will require a "trade data check" as part of the competitive analysis test.[97]

h) Streamlined Applications

113. A number of commenters have urged the Commission to allow small utilities that are unlikely to possess generation market power to submit streamlined applications.[98] Commenters argue that we should match the stringency of the market power determination process with the "reasonable inferences" about the market power risk posed by the applicant.[99] They state that certain sellers pose so little risk of generation market power that it would be a collective waste of resources to require a full study.[100]

[97] Order No. 642 at n. 41.

[98] See, e.g., January 2004 Comments of NRECA at 11; February 2004 Comments of NRECA at 2.

[99] See, e.g., February 2004 Comments of APPA/TAPS at 11-15.

[100] See, e.g., Technical Conference Comments of Dr. Joe Pace emphasizing that an abbreviated screening analysis for relatively small market participants (those controlling less than 10 percent of the generation resources) would provide an easy way to pass the test and would reduce data collection burdens. Technical Conference Tr. at 381-82, 400-03.

Duke Energy commented that we should emphasize section 35.27 to screen out applicants who presumptively do not have market power.[101]

114. We recognize the commenters' concerns that, in the case of small, independent power producers, a comprehensive generation market power analysis may not be necessary. Accordingly, we clarify that such power producers may avoid submitting an analysis if they meet the requirement of section 35.27 of our regulations (i.e., new capacity built after July 9, 1996), as clarified in subsequent cases.

115. The Commission determined in Kansas City Power & Light Company[102] that it is no longer necessary to examine generation market power when considering market-based rate applications for sales from new generation units. This was codified in Order No. 888, in section 35.27[103] of the Commission's regulations, providing, in relevant part, the following:

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

However, as the Commission stated in Order No. 888, we will consider whether an applicant, properly citing section 35.27, nevertheless possesses generation market power if specific evidence is presented by an intervenor.[104]

116. Order No. 888 also clarified that eliminating the requirement to demonstrate lack of market power in generation for new capacity does not affect the demonstration that an applicant must make in order to qualify for market-based rate authority for sales from existing generating capacity. Capacity, from both pre- and post-Order No. 888

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[101] See January 2004 Comments of Duke Energy at 4.

[102] 67 FERC ¶ 61,183 at 61,557 (1994).

[103] 18 C.F.R. § 35.27 (2003).

[104] See Order No. 888, supra, at 31,657.

generation, must be used to accurately determine a lack of generation market power.[105] Therefore, if an applicant sites generation in an area where it or its affiliates own or control other generation assets, the applicant must study whether its new capacity, when added to existing capacity, raises generation market power concerns.[106]

117. In addition, while there will be no safe harbor exemption from the screens based on the applicant's size, any applicant, regardless of size, has the option of making simplifying assumptions in its analysis where appropriate. Appropriate simplifying assumptions are those assumptions that do not affect the underlying methodology utilized by these screens. For example, if an applicant passes our generation market power screens by only considering the control area market's host utility as a competitor, we foresee no benefit from completing a study to include other competitors. Doing so would not change the results of the analysis.

i. Use of Historical Data

118. In performing all screens, applicants are required to prepare them as designed,[107] and must use the most recent unadjusted 12 months' historical data as a snapshot in time. Historical data have been proven to be more objective, readily available, and less subject to manipulation than future projections. Therefore, as an initial matter, the Commission will not permit applicants to make any adjustments to such data. Applicants filing abbreviated studies may request waiver of the full data requirements.

119. As discussed previously, applicants and intervenors may present evidence such as historical sales and transmission data. We believe that such data will provide an additional level of clarity to the wholesale markets and allow us to more precisely identify the potential for market power. In this regard, we will allow the introduction of such evidence beyond the most recent 12 months. We believe limiting historical sales and transmission data to only the most recent 12 month period may not provide the level

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[105] Id.

[106] See, e.g., LG&E Capital, 98 FERC at 62,034-35.

[107] Applicants presenting evidence that the relevant market is larger or smaller than the default relevant market (i.e., control area) must first complete the screens based on the control area as discussed above.

of clarity needed to analyze this type of information. Moreover, the use of unadjusted historical sales and transmission data will provide an accurate depiction of actual market activity. Therefore, the Commission will require applicants submitting historical sales and transmission data as evidence to submit the actual data. In this regard, applicants and intervenors may present their analysis of such data to demonstrate whether or not the applicant has generation market power.

C. Accommodations for Hydroelectric and Western Interconnect Issues

1. Rehearing/Intervention Comments

120. The SMA Order made no specific accommodations for hydroelectric power and for the Western Interconnect.

121. Several commenters express concern that the Pacific Northwest is a broader natural market area than would be reflected in a control area-by-control area approach. Commenters state that accommodations should be made for hydroelectric-based systems because overall capacity of hydroelectric-generation resources varies yearly.

122. In particular, PacifiCorp argues that the Commission erred in proposing to apply the SMA and associated mitigation without examining its appropriateness with respect to the WSCC. In this regard, commenters raise various concerns, including: Western power markets are unique when compared to Eastern markets; the SMA may have an adverse effect on RTO formation in the WSCC; any mitigation imposed on the WSCC should consider effects on the California markets; the SMA raises substantial risk of market distortions in the WSCC because of arbitrage opportunities between the jurisdictional market participants and the nonjurisdictional participants or participants who make substantial sales outside control areas where they own generation; WSCC retail customers will be harmed if LSEs are found to be pivotal suppliers; and mitigation measures cannot be meaningfully implemented in WSCC areas where there is substantial hydroelectric generation and storage.

2. Comments on Staff Paper

123. In response to the Staff Paper, BPA and PacifiCorp continue to argue that some recognition of energy limited units, e.g., hydroelectric generation, needs to be incorporated in the Commission's generation market power analysis. They argue that nameplate capacity is not a reliable measure by which to determine the capacity of a

hydroelectric plant; more relevant than nameplate capacity is the amount of energy a supplier has (and can retain) in storage on any given day.[108]

124. BPA states that for hydroelectric-plants, uncommitted installed capacity should be derated capacity to that which is supportable by energy to meet load under adverse conditions for long timeframes, i.e., a year or a critical season (used for run-of-the-river hydroelectric plants), or de-rated capacity to reflect sustained peaking capacity under adverse conditions for short timeframes, i.e. 50 hours (used for plants with significant storage flexibility).[109]

3. Technical Conference Comments

125. With regard to the SMA in the West, some commenters continue to argue for special accommodations for the West including: how capacity is calculated; the appropriate geographic area for the relevant geographic market (e.g., the entire Western Interconnect, Pacific Northwest, Desert Southwest, and California); and what effect mitigation will have on the West during poor water years (e.g., some argue that scarcity rents should be allowed to occur).[110]

4. Commission Determination

126. In the SMA Order, we made no special accommodations for hydroelectric facilities. However, we recognize the specific concerns that commenters, including BPA and PacifiCorp, have expressed regarding the appropriate measure of the capacity of hydroelectric units given that hydroelectric facilities are energy-limited units. Because using nameplate capacity can bias the results of a pivotal supplier or market share screen, with respect to such facilities, we will modify our approach. Therefore, we will permit applicants to de-rate their hydroelectric capacity in conducting the two interim generation market power screens. Applicants that elect to do this must de-rate their hydroelectric capacity based on historical capacity factors, and they should use a five-year average capacity factor and a sensitivity test using the lowest capacity factor in the previous five years in order to more accurately capture hydroelectric availability. Our experience with Western markets shows that market outcomes can be significantly different during low

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[108] See January 2004 Comments of PacifiCorp at 11-12.

[109] See January 2004 Comments of BPA at 3.

[110] See, e.g., January 2004 Comments of BPA at 3.

water years. We agree with the comments raised by western market participants and conclude that properly accounting for water availability will provide a better picture of competitive conditions in the West. Moreover, while not as critical in other parts of the country as in the West, the same principle regarding water availability applies to all electricity markets, and we will permit all applicants to de-rate hydroelectric capacity in the analysis.

127. In addition, some commenters have argued that the control area is not the proper definition for Western markets. They state that due to the integrated transmission system, and run-of-river hydroelectric systems, the West should be considered to consist of larger regional markets or even a single geographic market. We recognize that due to the integrated Western resource system, larger regional market definitions may be more appropriate, especially in the Northwest where hydroelectric power is such a critical part of the regional generation portfolio. As such, and consistent with our discussion of geographic areas above, we will allow applicants located in the Western interconnection to provide evidence that a larger geographic market definition than our control area-by-control area approach is appropriate.[111] Applicants making such arguments should justify their choice of market definition by citing the relevant facts and providing supporting data (i.e., historical sales indicating the actual scope of the market). Intervenors will have the opportunity to challenge applicants' assumptions and provide countervailing arguments.

D. Mitigation

1. Spot Market Mitigation

128. In the SMA Order, the Commission stated that the primary tools for exercising generation market power are physical and economic withholding. To prevent physical withholding, the Commission required that applicants who fail the SMA offer uncommitted capacity (i.e., generation in excess of each hourly projected peak load and minimum required operating reserves) for spot market sales in the relevant market. This requirement directed companies to post projected hourly incremental and decremental costs for the next day on their websites. To prevent economic withholding, the

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[111] Although we will consider such a showing, we still require that such applicants submit the generation market power screens adopted herein using the default relevant market(s).

uncommitted capacity would be priced in the spot market using the cost-based split-the-savings formula.[112] See SMA Order at section E.

129. The Commission reasoned that applying mitigation to spot market transactions will result in also mitigating generation market power in longer term (forward) markets by creating a kind of competitive "standard offer" service for customers. The Commission stated that if sellers attempt to charge excessive, non-competitive prices in forward markets, then customers can avoid such prices by waiting to purchase in the real-time market. This puts pressure on sellers to offer competitive prices in the forward markets. When sellers offer competitive forward prices, many buyers will prefer to purchase in the forward markets in order to gain price certainty.

a. Rehearing/Intervention Comments

130. On rehearing, commenters are highly critical of the mitigation measures discussed in the SMA Order.[113] Among other things, they claim that the spot market mitigation measure is overly simplistic, unsupported, and harmful to the market.[114] Some commenters also raise concerns regarding the constraints of other markets affecting the hourly energy markets (e.g., commodity natural gas, natural gas transportation, natural gas storage, and fuel oil).[115]

131. Commenters object to the requirement to post incremental and decremental costs and the requirement to offer uncommitted capacity into the market.[116] Some commenters

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[112] A seller's incremental cost (the out-of-pocket cost of producing an additional MW) is compared with a buyer's decremental cost (the cost of not producing the last MW). The average of the incremental and the decremental costs is the split-savings rate.

[113] See, e.g., Request for Rehearing of AEP at 31-37, Entergy at 32-49, Southern Companies at 10-17.

[114] See, e.g., Request for Rehearing of AEP at 31-35, Southern Companies at 11.

[115] See generally Request for Rehearing of Entergy at 33-34.

[116] See, e.g., Request for Rehearing of AEP at 33-36, Entergy at 33-41, Southern Companies at 35-38.

also complain that incremental and decremental information is confidential and commercially sensitive.[117]

b. PL02-8-000 October 2002 Comments

132. In the October 2002 comments, commenters generally reiterate concerns previously expressed as to the price mitigation measures in the SMA Order.[118] Duke suggests that, to the extent that an analysis indicates an applicant's potential ability to exercise market power, the applicant should be required to propose mitigation appropriate for its circumstances.[119]

133. CAISO contends that the SMA's spot market mitigation can only be effective if certain conditions exist.[120] In the alternative, CAISO proposes the use of long-term contracts to cure highly pivotal suppliers or spot market mitigation that requires a mitigated seller to offer available capacity at marginal cost.[121]

134. Commenters continue to object to the split-the-savings rate.[122] They argue, among other things, that split-the-savings rates will depress short and long-term power prices in the mitigated control area, discourage construction of new generation, distort market prices, and distort power flows and capture transmission capacity that is needed by competing generators.

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[117] See, e.g., Request for Rehearing of AEP at 33, Entergy at 43-44, Southern Companies at 35-38.

[118] See, e.g., October 2002 Comments of AEP at 1 (incorporating by reference its Request for Rehearing at 31-37), APPA/TAPS at 32-37, Calpine at 4, Duke at 8, Southern Companies at 10-11.

[119] See October 2002 Comments of Duke at 9 (proposing alternatives).

[120] CAISO asserts that SMA will be effective only assuming that the decremental cost value is closely tied to the incremental cost value; there is excess capacity from competitive suppliers in the market; and suppliers do not collude with each other. See October 2002 Comments of CAISO at 21-22.

[121] See id. at 22-23.

[122] See, e.g., October 2002 Comments of AEP at 4, CP&L at 8-13, Allegheny at 7, Southern Companies at Appendix 14-20 (Affidavit of Frame).

135. Many commenters also continue to object to posting of incremental and decremental costs, arguing that such a requirement would harm competition. However, others supports posting of incremental costs.[123]

c. Staff Paper Proposal

136. Largely in response to the many comments received, in the Staff Paper included in the December 2003 Notice, staff proposed significant modifications to the SMA Order's spot market mitigation. With respect to the mitigation itself, staff proposed two methods: a traditional cost-based rate that could be based on an average cost of the units expected to run to meet peak demand or based on an average system or regional cost. Another mitigation method staff proposed was a single market clearing price methodology. The single market clearing price would be the price for any hour that corresponds to a total quantity of energy that just balances the accepted supply offers with the accepted purchase bids.

137. Under both of these methods, staff raised the issue of whether the mitigation should only be applied seasonally (e.g., by identifying only the specific seasons in which a utility is found to have generation market power). Also, staff raised the issue of whether the Commission should require utilities subject to the single market clearing price mitigation to file incremental and decremental costs on a confidential basis.

d. Comments on Staff Paper

138. Several commenters argue that the Commission should allow utilities to propose mitigation tailored to their own particular circumstances.[124] For example, Duke suggests that possible alternatives could include: establishment of a trading hub in the control area; unit-specific caps for resources located in load pockets; caps on spot-market sales at some percentage of day-ahead prices established in adjoining regions that have implemented Commission-approved bid-based energy markets; retention of an independent third-party to monitor for market power; or setting aside a certain amount of

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[123] See, e.g., October 2002 Comments of CAISO at 22.

[124] See, e.g., January 2004 Comments of Southern Companies at 19 (arguing that applicants that fail the market screen should be given the opportunity to propose mitigation measures tailored to their particular circumstances), Cinergy (Affidavit of Solomon) at 7, Exelon at sec. VIII, PacifiCorp at 19-21; WPS Companies at 12.

transmission capacity on one or more transmission interfaces to help bring in competing supplies.[125]

139. Entergy argues that mitigation should only be applied after an evidentiary hearing.

e. Technical Conference Comments

140. For the most part, commenters reiterate positions they have taken in prior comments in this proceeding. Some commenters (representing both vertically-integrated utilities and consumer groups) argue that any mitigation adopted by the Commission should try to simulate the competitive market price, not substitute it with cost-of-service rates.[126]

141. Most commenters addressing mitigation in their supplemental comments ask the Commission to tailor mitigation to the particular circumstances of the applicant being mitigated.[127] APPA/TAPS reiterates the request to "surgically craft a remedy" in response to the particular facts of a case.[128] Exelon submits that the Commission should allow failing applicants to propose mitigation, regardless of whether it adopts default mitigation.[129] Southern Companies asks that the Commission not mandate a "one-size-

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[125] See January 2004 Comments of Duke at 6.

[126] See, e.g., February 2004 Comments of Duke Energy at 6, EME at 4-6, EPSA at 8-9, Exelon at 9 (Attachment A, Final Comments of Hieronymus), Southern Companies at 2, WPS Companies at 12. Louisiana Commission states that any mitigation measures should not harm retail customers.

[127] See, e.g., February 2004 Comments of AEP at 10-12 (Further Comments of Pace), APPA/TAPS at 18, Duke Energy at 6, Exelon at 4 (sec. VI), PacifiCorp at 9-10, Southern Companies at 2, Steel Producers at 5-6, WPS Companies at 12.

[128] See February 2004 Comments of APPA/TAPS at 51-52.

[129] See February 2004 Comments of Exelon at 7 (Attachment A, Final Comments of Hieronymus).

fits-all" mitigation measure.[130] AEP adds that mitigation is difficult to generalize because effective measures turn on the facts of each case.[131]

142. Montana Consumer Counsel believes that receipt of a just and reasonable cost-based rate, rather than a market-based rate, is appropriate and not confiscatory, and that any supplier found to possess market power must agree to appropriate mitigation or lose its market-based rate authority.[132] APPA argues that when the Commission concludes a seller possesses market power, the FPA requires the Commission to analyze a seller's market power potential in all jurisdictional markets – spot, forward, long-term, bilateral, and ISO/RTO. The Commission should look to cost-based remedies for mitigation because they assure just and reasonable rates and work in the context of both ISO/RTO and non-ISO/RTO markets. Tractebel believes that a failing applicant should be required to adopt Commission-approved cost-of-service rates, or to initiate a short-term procurement process that uses security constrained economic dispatch.[133] Steel Producers support cost-based rates as the default mitigation, but add that mitigation should not be limited to the spot markets and that the Commission, should at a minimum, retain flexibility to impose mitigation in the forward markets as well as in the spot markets if circumstances dictate that such mitigation is appropriate.[134]

f. Commission Determination

143. As an initial matter, the Commission has a responsibility under the FPA to ensure that jurisdictional rates in the wholesale markets are just and reasonable. Our responsibility is to ensure that sellers not charge unjust and unreasonable wholesale rates, and that the market structures and market rules governing public utility sellers, and affecting the wholesale rates of such public utility sellers, do not result in, wholesale rates that are unjust, unreasonable, unduly discriminatory, or preferential.

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[130] See February 2004 Comments of Southern Companies at 14.

[131] See February 2004 Comments of AEP at 10-12 (Further Comments of Pace).

[132] See February 2004 Comments of Montana Consumer Counsel at 6.

[133] See February 2004 Comments of Tractebel at 8.

[134] See February 2004 Comments of Steel Producers at 5-6; see also February 2004 Comments of ETC at 4-6.

144. The FPA requires that all rates charged by public utilities for the transmission or sale for resale of electric energy be "just and reasonable."[135] Where there is a competitive market, the Commission may rely on market-based rates in lieu of cost-of-service regulation to ensure that rates satisfy this requirement.[136] Consistent with our precedent, the Commission authorizes sales of electric energy at market-based rates only if the seller and its affiliates do not have, or have adequately mitigated, market power in the generation and transmission of such energy, and cannot erect other barriers to entry by potential competitors.[137] Thus, where a market-based rate applicant is found to have market power (e.g., after reviewing an applicant's Delivered Price Test), it is incumbent upon the Commission either to reject such rates or to ensure that adequate mitigation measures are in place to ensure that the rates are just and reasonable.

145. As noted above, some commenters were critical of the spot market mitigation adopted in the SMA Order. Among other things, these commenters object to the requirement to post incremental and decremental costs and the requirement to offer uncommitted capacity into the market. According to Entergy, unless all market participants are required to simultaneously post their forecasted hourly incremental and decremental costs, gaming could occur and trade benefits will not be divided equally between the buyer and seller.[138] Some commenters also complain that incremental and decremental information is confidential and commercially sensitive. FirstEnergy, Duke Power, and the Florida Commission argue that posting offers would give an advantage to competitors. AEP expresses concern that the posting requirement presents opportunities for market participants to game the system to the detriment of AEP and its ratepayers.[139] Others, such as Oklahoma Municipal Power Authority, support requiring incremental and decremental costs to be posted.

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[135] 16 U.S.C. § 824d(a) (2000).

[136] Cf. Elizabethtown Gas Co. v. FERC, 10 F.3d 866, 870 (D.C. Cir. 1993) (discussing "just and reasonable" rate requirement of Natural Gas Act).

[137] See, e.g., Heartland Energy Servs., Inc., 68 FERC ¶ 61,223 at 62,060 (1994); Louisville Gas & Elec. Co., 62 FERC ¶ 61,016 at 61,143-44 (1993).

[138] See Request for Rehearing of Entergy at 41-42.

[139] See Request for Rehearing of AEP at 36.

146. Southern Companies asserts that mandatory purchases and sales, along with posted cost information, will harm retail customers, threaten reliability, and handicap the company's ability to negotiate beneficial terms for serving native load customers.[140] AEP raises similar arguments.[141]

147. Among other things, we have heard the strong opposition expressed by some commenters with regard to posting incremental and decremental costs, mandatory offering of uncommitted capacity into the market, and mandatory purchases. Although we continue to believe that transparency is an important feature of a competitive market, we will change our approach in this regard. We will replace the mitigation for spot market energy sales that was originally proposed including posting of incremental costs. We will also allow applicants to propose case-specific mitigation tailored to their particular circumstances that eliminates the ability to exercise market power, or adopt cost-based rates such as the default rates herein.

148. Allowing applicants to propose their own mitigation is one of the most commented on aspects of mitigation, with many commenters arguing for such an option. We will grant such an option.[142] However, as a backstop measure, we will also provide "default" rates to ensure that wholesale rates do not go into effect, or remain in effect, without assurance that they are just and reasonable. If an applicant does not pass the generation market power screens, or foregoes the screens entirely, the Commission will set the just and reasonable rate at the "default" rate unless it approves different cost-based rates for that applicant based on case-specific circumstances.

149. Applicants that have a presumption of market power (i.e., those failing one or both of the indicative screens) will have their rates prospectively made subject to refund.[143]

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[140] See Request for Rehearing of Southern Companies at 10-17.

[141] See Request for Rehearing of AEP at 31-36.

[142] Proposals for alternative mitigation in these circumstances could include cost-based rates or other mitigation that the Commission may deem appropriate. For example, an applicant could propose to transfer operational control of enough generation to a third party such that the applicant would satisfy our generation market power concerns.

[143] The refund floor would be the default cost-based rates or, if applicable, any case-specific cost-based rates proposed by the applicant and accepted by the Commission. Accordingly, the applicant has certainty as to its potential refund obligation, if any.

Market-based rates will not be revoked and cost-based rates will not be imposed until there has been a Commission order making a definitive finding that the applicant has market power (i.e., after the Commission has ruled on a Delivered Price Test analysis) or, where the applicant accepts a presumption of market power, an order is issued addressing whether default cost-based rates or case-specific cost-based rates are to be applied.

150. As discussed herein, we will revoke the market-based rate authority in all geographic markets where an applicant is found to have market power.[144] Such applicants will be required to adopt some form of cost-based rates or other mitigation the applicant proposes and the Commission accepts. Under these circumstances, we find that it is essential that appropriate accounting records be maintained consistent with our regulations. Accordingly, where an applicant is found to have market power, we will no longer waive our otherwise applicable accounting regulations (e.g., Parts 41, 101, and 141 of the Commission's regulations). Further, we will not grant blanket approval for issuances of securities or assumptions of liability pursuant to Part 34 of the Commission's regulations for the applicant and its affiliates.

151. We adopt default rates tailored to three distinct products, as follows: (1) sales of power of one week or less will be priced at the applicant's incremental cost plus a 10 percent adder; (2) sales of power of more than one week but less than one year will be priced at an embedded cost "up to" rate reflecting the costs of the unit(s) expected to provide the service; and (3) sales of power for more than one year will be priced on an embedded cost of service basis and each such contract will be filed with the Commission for review and approved prior to the commencement of service.[145]

152. With regard to sales of power of one week or less, an incremental cost rate that allows a fair recovery of the incremental cost of generating with a 10 percent adder to provide for a margin over incremental cost is reasonable. Absent market power, a generator would typically run if it had excess power and could cover its incremental costs plus some return. In addition, customers will be protected against any exercise of market

[144] The applicant has the option of withdrawing its market-based rate request in whole or in part.

[145] We note here that, to the extent a party believes market power is being exerted in the course of negotiating a long-term purchase, such party may file a complaint pursuant to section 206 of the FPA.

power in spot markets in these circumstances because the mitigated applicant will not have an opportunity to charge excessive rates.[146]

153. With respect to sales of power for more than one week and less than one year, we do not believe such sales are necessarily opportunity sales. Such sales often require a greater commitment on the part of the seller (firm sales). Therefore, a greater degree of pricing flexibility and the opportunity to obtain fixed cost recovery in the price is reasonable. Accordingly, we will adopt an embedded "up to" cost-based rate based on those units expected to run to meet these types of sales.[147] The Commission has established a body of precedent for the determination of such rates, consistent with the FPA, which provides the seller a just and reasonable ceiling price through which it is authorized to enter into economic transactions subject to that ceiling price. The rate is premised upon the costs of the units in the seller's system from which such sales are anticipated, recognizing that such wholesale sales are generally made from a specific fleet of units. Buyers are protected from the exercise of market power by such a ceiling price. The Commission's existing precedent providing for such rates provides a clear established methodology for their development and implementation.

154. In the SMA Order, the Commission stated its belief that adequately mitigating market power in short-term markets would also mitigate market power in long-term markets. However, several commenters since that time have challenged that assumption.[148] Thus, the Commission's December 2003 Staff Paper specifically asked for public comment on whether the Commission should retain the assumption it had relied on in the SMA Order regarding the mitigation of market power in long-term markets. Following the issuance of that Staff Paper, several commenters again encouraged the Commission to abandon this assumption – including several new

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[146] In PJM, for example, generators dispatched out of economic merit have their bids mitigated to incremental costs plus 10 percent to prevent them from exercising market power and, at the same time, providing revenues which include a margin. See Amended and Restated Operating Agreement Of PJM Interconnection, L.L.C. (Third Revised Rate Schedule FERC No. 24, Issued Feb. 1, 2004) at pp. 148-51 (Original Sheet No. 129, First Revised Sheet No. 130, Original Sheet No. 131, First Revised Sheet No. 132).

[147] See, e.g., Illinois Power Company, 57 FERC ¶ 61,213 at 61,699-700 (1991).

[148] See, e.g., Request for Rehearing of EPSA at 10-11, October 2002 Comments of APPA/TAPS at 33-34; SMUD at 16; Steel Producers at 5.

commenters that made this claim.[149] In light of these comments, if an applicant fails one of our indicative screens and the Delivered Price Test, we must conclude, absent some further showing otherwise, that such applicant has the potential to exercise market power for all power sales regardless of the sale's duration. Accordingly, to the extent an applicant is found to have market power and is not otherwise mitigated, we will require that long-term sales into the relevant market where the applicant has market power be priced at embedded cost-based rates. However, we emphasize that our imposition of this remedy to long-term markets – as well as to shorter-term markets – is prospective only.

155. We will require all long-term sales (one year or more) into any market where the applicant has market power to be filed with the Commission for review and approval prior to the commencement of service, and to be priced on an embedded cost-of-service basis.[150] Here we are noting that, in instances where we have found the potential for market power, long-term markets have not necessarily been shown to be inherently competitive. Although buyers do have more alternatives in long-term markets (including in certain circumstances building a new generating facility) than they would in short-term markets, we recognize that there are impediments to those alternatives. As noted by APPA's witness, Dr. Kirsch, there are a number of reasons why market participants do not have the option of building capacity at a competitive cost, including lumpy generation investment, insufficient transmission access, and insufficient access to fuels.[151] Further, depending upon the facts and circumstances, a new generating facility is not always a comparable or feasible alternative to a long-term purchase. As such, the theoretical ability to undertake such construction does not, per se, mitigate the ability to exercise

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[149] See, e.g., January 2004 Comments of CEOB at 3; February 2004 Comments of APPA/TAPS at 40-41; NRECA at 13; Technical Conference at Tr. 2 (Testimony of Craig Roach), Tr. 50-55 (Comments of Jesse Tilton), February 2004 Comments of ETC at 4-6.

[150] This long-term mitigation does not preclude a utility found to have market power from participating as a seller in any request for proposals (RFPs), but does require that any rates offered by such utility in the course of an RFP be priced to not exceed embedded costs.

[151] See February 2004 Comments of APPA at Kirsch Affidavit at 5. The concern with "lumpy" investment is that an LSE with a specific capacity need may not be able to build a facility to match that need. If it is too small, then the LSE will still need to buy long-term capacity and energy. If it is too big, then the LSE will be "long" and need to sell the power and may not have any customers, or many not have any interest in being a seller.

market power. Our reliance upon such a theoretical possibility could be an oversimplification which may fail to protect customers under many real facts and circumstances. Thus, in keeping with our obligation under the FPA to ensure that sellers not charge unjust and unreasonable wholesale rates, we will require mitigated applicants to file such long-term contracts and not transact under such contracts without first receiving Commission approval.[152]

2. Size Mitigation

156. In the SMA Order the Commission stated that imposing cost-based rates mitigates an applicant's ability to raise generation prices but does nothing to mitigate the core problem, which is the relative size of an applicant. In an effort to increase supply in the applicant's core market and thereby reduce the applicant's relative size, the order required that when a transmission provider performs a study pursuant to an interconnection request (e.g., feasibility, system impact, or facility study), an unaffiliated entity, such as a merchant generator, may request that the output of the proposed project be modeled for study purposes to serve load within the control area within which it is located without having to formally designate a particular load or without having to be selected as a designated network resource at the time of interconnection. An unaffiliated entity would be treated as a competing network resource in meeting load and load growth. In addition, applicants were directed to post on their websites the optimum areas on their systems for locating prospective generating facilities. Applicants were directed to identify areas of expected load growth requiring transmission expansion or siting of new generation, and areas on the system that can accommodate new generation without system upgrades.[153]

a. Rehearing/Intervention Comments

157. In its request for rehearing, Southern Companies questions the need for the requirement that merchant plants be treated as native load resources during the interconnection process. Southern Companies states that it already offers to model

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[152] Because we are imposing this filing requirement where an applicant is found to have market power, any such long-term contract would be a non-conforming contract as defined by § 35.1(g) of the Commission's Regulations. As such, each contract would have to be both filed with the Commission for approval and reported in the Electronic Quarterly Reports.

[153] See SMA Order at section II.F.

proposed merchant plants as native load resources in Section 1.2 of Southern Companies' Procedures for Obtaining Interconnection Service. Thus, it submits that it is already in compliance with that portion of the Order.

158. Entergy argues that the Commission has offered no evidence that this mitigation measure will result in a material increase in new requests to interconnect to Entergy's system and claims that there has already been an "explosion" of new merchant generation in Entergy's service territory, obviating the need for this mitigation measure. Entergy also objects to posting "optimum" generation sites on its OASIS. It states that price signals from a properly working market, not OASIS postings, should guide siting decisions.

159. AEP states that it is already in basic compliance with the directive that it post and offer on a website a portfolio of longer term products and prices available to entities in AEP's control area.[154]

160. Several other commenters, such as EPSA and Calpine, support the proposal that interconnection customers be treated as a competing network resource, and that optimal areas for locating generation be posted.

161. On January 4, 2002, AEP, Entergy, and Southern Companies filed reports addressing their compliance with the mitigation imposed in section II.F of the SMA Order. AEP, Entergy, and Southern Companies each indicated that they had posted on their websites information as to optimum areas on their systems for locating prospective generating facilities.[155] The companies generally represent that the postings do not address potential environmental issues, zoning issues, or fuel availability considerations. In addition, the postings include a number of disclaimers, including that the postings do not guarantee that any generators can interconnect in those areas, and that system upgrades may be required.

162. With respect to the interconnection study requirement, AEP and Entergy reported that, pending resolution of their respective requests for rehearing, if requested by an entity seeking an interconnection, they would perform a study (feasibility, system impact,

[154] Request for Rehearing of AEP at 7.

[155] Each company indicated that while it would update its website quarterly, it did not intend to make separate quarterly reports for each update.

or facility) that models the proposed generating facility as a network resource serving load within the control area in which it is located.

b. PL02-8-000 October 2002 Comments

163. Commenters generally raise the same concerns as on rehearing. Exelon states that new interconnection policies are unwarranted as this form of mitigation is plainly irrelevant to any current ability of an applicant to exercise market power.

c. Staff Paper Proposal/Technical Conference Comments

164. Staff's paper did not address this aspect of the mitigation directed in the SMA Order. In the supplemental comments, Steel Producers state that they continue to support the requirement from the SMA Order that an unaffiliated entity may request that the output of its proposed project be modeled for study purposes to serve load within the control area in which it is located, without having to formally designate a particular load or without having to be selected as a designated network resource.

d. Commission Determination

165. With respect to the comments raised concerning the requirement in the SMA Order that a mitigated transmission provider study a merchant generator as a network resource when requested to do so by the merchant generator pursuant to its interconnection request and post optimum generation sites, the Commission subsequently addressed these issues in its interconnection rulemaking proceeding, Order No. 2003.[156] In Order No. 2003-A, the Commission has recently identified the importance of all transmission owners posting optimum generation sites on their OASIS, and in that order the Commission strongly encouraged all transmission owners to do so. The need to post this information on OASIS is heightened in the case where a transmission owner (or its affiliate) has generation market power.

166. Because the instant order does not make any findings as to whether AEP, Entergy, and Southern Companies pass the new interim screens we adopt herein and thus whether

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[156] See Standardization of Generator Interconnection Agreements and Procedures, Order No. 2003, 68 Fed. Reg. 49,845 (Aug. 19, 2003), FERC Stats. & Regs., Regulations Preambles P 31,146 (2003) (Order No. 2003), order on reh'g, Order No. 2003-A at P 531, 69 Fed. Reg. 15,932 (March 26, 2004), FERC Stats. & Regs., Regulations Preambles P 31,160 (2004) (Order No. 2003-A); see also Notice Clarifying Compliance Procedures, 106 FERC P 61,009 (2004).

any of these companies has a presumption of generation market power based on the interim screens, we will grant rehearing with regard to the mitigation for size imposed in the SMA Order (Section II. F.) However, we will require the posting of optimum generation sites on OASIS for those who are found to have generation market power.

3. Control Mitigation

167. The SMA Order required Entergy and Southern Companies to employ an independent third party to operate and administer their OASIS sites.[157] The Commission stated in the SMA Order that this requirement addressed concerns about the integrity of the postings of ATC on Entergy and Southern Companies' OASIS[158] and ensures that available competing supplies are deliverable.[159]

a. Rehearing/Intervention Comments

168. Entergy and Southern Companies object to the mitigation measure requiring them to have an independent third-party operate their OASIS, protesting what they regard as the Commission's agreement with unsubstantiated allegations raised by power marketers and the failure to allow them to respond adequately to such allegations.[160] Southern Companies points out that the Commission had recently audited its OASIS and found few problems and none warranting this type of remedy. It claims that the costs of the operator will be borne by native load, and that the operator cannot duplicate the expertise of its own employees and thus might adversely impact reliability. Southern Companies and Entergy both claim that they will soon be members of an RTO, and the presence of an independent OASIS operator for the short period of time before that happens might complicate the transition and be a waste of resources.

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[157] See SMA Order at section II.G.

[158] Specific concerns raised by intervenors include zero posting of ATC, allegations of favorable treatment for affiliates, and posting inaccurate information.

[159] See SMA Order, 97 FERC ¶ 61,219 at 61,973 (2001). The SMA Order noted that AEP was in compliance with this requirement due to its meeting the Commission's merger condition in American Electric Power Co. and Central and SouthWest Corp., 91 FERC ¶ 61,208 at 61,747-48 (2000).

[160] AEP does not raise this issue, since it earlier agreed to have its OASIS operated by Southwest Power Pool as part of the AEP-CSW merger proceeding.

169. Entergy also complains that an independent OASIS operator is a mitigation measure that is not tailored for the market power finding of the Commission's order.[161] A number of other commenters also question the need for an independent third party to operate and administer the OASIS site.[162]

170. On January 10, 2002, Entergy and Southern Companies submitted status reports of their plans to employ an independent third party to operate and administer their OASIS sites. Both reserved the right to challenge the requirement on rehearing. Entergy informed the Commission that it would comply with the requirement to employ an independent third party to operate and administer its OASIS site by supporting and facilitating the rapid selection of the SeTrans Independent System Administer (ISA) and by expeditiously transferring control of the Entergy OASIS site to the SeTrans ISA on an interim basis.[163]

171. Southern Companies stated that, due to efforts to develop SeTrans (which would satisfy the SMA Order in this regard), it would not employ a third party to operate and administer its OASIS site on an interim basis because doing so would unnecessarily consume time and resources, and divert attention from a more permanent resolution. Instead, Southern Companies stated that it would engage SeTrans' ISA "as expeditiously as possible" to facilitate the transfer upon approval of the SeTrans RTO.

b. PL02-8-000 October 2002 Comments

172. Commenters generally raise the same concerns as on rehearing. A number of commenters state that the requirement for an independent OASIS operator is a remedy

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[161] See Request for Rehearing of Entergy at 47-49 (stating that the Commission determined that Entergy had horizontal market power, yet the independent OASIS operator requirement is a remedy for vertical market power).

[162] See, e.g., Request for Rehearing of FirstEnergy at 20-21, Mississippi Commission at 10-11, Exelon at 23, Duke Power at 11, Louisiana Commission at 9, Alabama Commission at P 6.

[163] On January 12, 2004, in Docket Nos. ER02-2014-000 and ER03-1272-000, Entergy submitted a letter to the Commission stating its intent to voluntarily file on or before March 31, 2004, under section 205 of the FPA, a proposal to create an independent transmission entity to oversee the provision of transmission service on the Entergy system.

for vertical market power, not horizontal market power.[164] Others, such as TECO Energy and Calpine, support third-party administration of OASIS sites.[165]

c. Staff Paper Proposal/Technical Conference Comments

173. The Staff Paper did not address this aspect of the mitigation directed in the SMA Order. In its supplemental comments following the technical conference, EPSA states that the Commission should put in place an independent entity to administer certain transmission functions for vertically integrated utilities and their affiliates that do not pass the Commission's generation market power screens. Specifically, EPSA urges that the OASIS site should be operated by a third-party entity, which should also be responsible for calculating and posting TTC and ATC, and also manage or oversee the process of performing transmission studies needed to handle interconnection requests.[166]

174. Steel Producers also support the requirement that parties failing the market power test employ an independent third party to operate and administer their OASIS sites.[167]

d. Commission Determination

175. Upon reconsideration, we will grant the rehearing requests of Entergy and Southern Companies of our decision directing Entergy and Southern Companies, as part of the mitigation imposed in the SMA Order (section II.G), to employ an independent third party to operate and administer their OASIS sites. In granting rehearing, however, we make no findings as to the merits of the arguments raised in this proceeding on this issue. Rather, we agree with commenters that such mitigation has a stronger nexus to issues of transmission market power than to the generation market power analysis adopted herein. Accordingly, we will consider the issue of whether there is a need to mitigate access to, and information on, transmission facilities in other proceedings, as may be appropriate.

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[164] See, e.g., October 2002 Comments of Entergy at 8-9, Exelon at 23, Mississippi Commission at 10-11.

[165] See October 2002 Comments of Calpine at 5, TECO Energy at 10.

[166] See February 2004 Comments of EPSA at 6-7.

[167] See February 2004 Comments of Steel Producers at 7.

E. ISO/RTO Exemption

176. In the SMA Order, the Commission stated that all sales, including bilateral sales, into an ISO or RTO with Commission-approved market monitoring and mitigation are exempt from the SMA and, instead, will be governed by the specific thresholds and mitigation provisions approved for the particular market.

1. Rehearing/Intervention Comments

177. In the comments and requests for rehearing of the SMA Order, several entities oppose exempting from the SMA those entities that make sales to an ISO/RTO with Commission-approved market monitoring and mitigation measures.[168] Opponents generally assert that the SMA Order erroneously assumes that existing ISO or RTO market monitoring and mitigation plans fully address market power concerns. FirstEnergy argues that the effect of the exemption is to unfairly penalize utilities that are not participating in RTOs, particularly in instances where the failure to do so arises from the Commission's own inaction in approving an RTO.[169]

178. San Francisco argues that in many instances the ISO/RTO exemption of sales will permit applicants who possess market power to engage in market-based rate sales without any protecting mitigation measures.[170] Moreover, San Francisco and APPA argue that the Commission's generation market power test recognizes that utilities can and do make sales to markets outside of the ISO/RTO where they are located, and this "export" capacity should be considered within the relevant market.[171]

179. In contrast, other commenters support the exemption. Duke Energy suggests that the Commission expand safe harbor exemptions to any market in which participants agree to be bound by an appropriate Commission-approved market monitoring and mitigation plan, regardless of whether an ISO/RTO is operational in the region.

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[168] See, e.g., Request for Rehearing of APPA at 16, NSTAR at 6-9, NRECA at 11-12, FirstEnergy at 9-10, CEOB at 9-12, San Francisco at 10-11, ELCON at 3-6.

[169] See Request for Rehearing of FirstEnergy at 9.

[170] See Request for Rehearing of San Francisco at 10-11.

[171] See id., APPA at 16.

2. PL02-8-000 October 2002 Comments

180. In the October 2002 comments, commenters remained divided as to the merits of the ISO/RTO exemption. Opponents of the ISO/RTO exemption cite the ability to exercise market power within an ISO/RTO as the basis for their request that the Commission apply the SMA to all suppliers, including those suppliers that participate in ISOs/RTOs with market monitors.[172] The Connecticut PUC argues that the market monitors in presently centralized markets with market monitoring and mitigation are unequipped to mitigate market power in unconstrained areas, and tend to lack the authority to order refunds or apply remedies that have sufficient financial consequences to act as a deterrent.[173] NSTAR states that the Commission should apply the SMA to all entities as there is no evidence that ISOs have mitigated effectively the exercise of market power.[174] Old Dominion states that the ISO/RTO exemption would ignore transmission constraints and the heightened ability to exercise market power in a load pocket area.[175]

181. SMUD proposes removal of the exemption, but alternatively, requests clarification that the Commission will impose a refund condition on market-based rates of public utility sellers in the event that the Commission finds the seller to have engaged in anti-competitive conduct.[176] New Smyrna requests a case-by-case application of the exemption if the Commission does not withdraw its proposal to exempt sellers from the applicable generation market power test.[177] New Smyrna cites California and New

[172] See, e.g., October 2002 Comments of Connecticut PUC at 3, Rayburn at 4-11, Steel Producers at 6-7, Joint Consumer Advocates at 4-5, and NRECA at Attachment A, 11, Citizen Power at 1, New Smyrna Beach at 3, Old Dominion at 3-6, CAISO at 24-25, NSTAR at 5-6, SMUD at 7-11, Seminole at 7-8, APPA/TAPS at 16, ELCON at 4-7, and Florida Industrials at 10-11.

[173] October 2002 Comments of Connecticut PUC at 3-4.

[174] October 2002 Comments of NSTAR at 2, 5-6.

[175] October 2002 Comments of Old Dominion at 6.

[176] October 2002 Comments of SMUD at 3.

[177] October 2002 Comments of New Smyrna at 7-8.

England, regions in which ISOs have operated with market mitigation powers, as examples of markets that can work in unanticipated ways.[178]

182. Supporters of the exemption, on the other hand, argue that the more pervasive, rigorous, and targeted mitigation in ISOs/RTOs with Commission-approved market monitoring and mitigation, including the level of independence and market oversight, vitiates the need for an applicant-specific market power test.[179] FirstEnergy agrees that it is appropriate to exempt from the SMA generation owners that sell into a fully operational ISO/RTO that has Commission-approved market monitoring and mitigation procedures because those markets are generally expected to be large markets in which there are many potential sellers and more fully-developed regional spot markets.[180]

183. The PSEG Companies claim that the best tools to deal with the potential abuse of market power are those found in competitive wholesale energy markets operated by RTOs with well-designed and Commission-approved market monitoring units, which it claims address locational market power in instances where generators are in a must-run situation.[181]

3. Staff Paper/Technical Conference Comments

184. In the Staff Paper, staff invited comments on whether the ISO/RTO exemption should be continued. In the responses to the Staff Paper, in testimony at the technical conference, and in the post-technical conference comments, commenters remain split on whether sales into an ISO/RTO with Commission-approved market monitoring and mitigation should be exempt from the generation market power analysis. Several commenters maintain that the Commission should continue to exempt from the market power analyses any generation located in an approved ISO and/or RTO with

[178] See October 2002 Comments of New Smyrna at 3; see also Florida Industrials at 2.

[179] See, e.g., October 2002 Comments of AEP at 1, Calpine at 3, EPSA at 4, Williams at 3, Allegheny at 8, FirstEnergy at 13, Exelon at 4, Dominion Resources at 1, 5-6, and PSEG.

[180] October 2002 Comments of FirstEnergy at 13.

[181] October 2002 Comments of PSEG Companies at 2, 5-6, 10.

Commission-approved market monitoring and mitigation procedures in place.[182] Cinergy Services, Inc. (Cinergy), moreover, urges the Commission to be flexible by taking into account the progress a newly-forming ISO/RTO is making when allowing for the exemption and by not taking a bright line approach on the exemption.[183] EEI, BPA, Exelon, the Northeast System Operators (NYISO, ISO New England and PJM Interconnection, LLC), the PSEG Companies, Southern California Edison, Tractebel, and the WPS Companies support continuation of the exemption from the generation market power test for sellers in ISOs or RTOs with Commission-approved market monitoring and mitigation measures. The Northeast System Operators explain that their markets provide transparency that does not exist in markets that are not administered by Commission-accepted ISOs or RTOs. The PSEG Companies state that while they do not wish to suggest that market power cannot exist within an ISO or RTO, the proposed exemption recognizes that the tools to monitor and mitigate such market power already are in place. The PSEG Companies state that the proposed exemption should also apply to a new control area joining an independent ISO or RTO with a Commission-approved market monitoring unit.

185. At the same time, other commenters continue to oppose the exemption and argue that the Commission should apply the market power test in all market areas, including those with an ISO/RTO in place.[184] For example, ELCON argues that the mere formation of RTOs does not guarantee that the initial RTO market design will be flawless, or that all forms of market power are mitigated. NRECA states that the Commission should not simply assume that such market monitoring and mitigation mechanisms can substitute for a searching Commission examination of potential market power in such markets. According to NRECA, a seller should not get a free pass simply because it is selling into an ISO/RTO with a meaningful market monitoring mitigation mechanism, but this fact should be considered as a mitigating circumstance if a seller fails the relevant test(s).

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[182] See, e.g., January 2004 Comments of AEP at 2, Cinergy at 5 and App. at 7 (Affidavit of Solomon), Dominion Resources at 1, 4, Duke Energy at 2, FirstEnergy at 7-8, NYISO at 2-5, PacifiCorp at 6-7, and PSEG Companies at 2-3.

[183] January 2004 Comments of Cinergy at 5-6.

[184] See, e.g., January 2004 Comments of CEOB at 2, ELCON at 4, Joint Consumer Advocates at 12-16, NRECA at 3, 12-13, and Seminole at 10-11; see also February 2004 Comments of NRECA at 14-16, APPA/TAPS at 44-47, SMUD at 5-6, and Steel Producers at 6-7.

4. Commission Determination

186. We recognize the pro-competitive benefits of an ISO/RTO including a market of appreciable size and scope that is subject to market monitoring and mitigation. We also believe that subjecting applicants that own or control generation within an ISO/RTO to our indicative screens will provide a further vehicle to check on the potential for market power. Accordingly, we will grant rehearing with respect to the exemption from the generation market power analysis for sales into an ISO or RTO with Commission-approved market monitoring and mitigation, and require all applicants for market-based rate authority to submit the generation market power analyses adopted herein.[185]

187. Similar to our approach under the hub-and-spoke analysis, when performing the generation market power screens adopted herein, applicants located in ISO/RTOs with sufficient market structure and a single energy market may consider the geographic region under the control of the ISO/RTO as the default relevant geographic market for purposes of completing their analyses (e.g., PJM, ISO-NE, NYISO, and CAISO).

188. The ISO/RTO-wide geographic market delineation would not be appropriate for MISO or SPP at this time because neither performs functions such as a single central commitment and dispatch. We note that pending before the Commission is MISO's tariff filing proposing to establish an energy market effective December 1, 2004. Once MISO becomes a single market and performs functions such as single central commitment and dispatch with Commission approved market monitoring and mitigation, MISO would be considered to have a single geographic market for purposes of our generation dominance screens. Likewise, SPP which has been granted conditional RTO status will also be considered under this same framework once it files and obtains Commission approval of its compliance filing and begins to perform functions such as single central commitment and dispatch. Until such time, applicants located in MISO and SPP will be treated as stand alone utilities for purposes of our generation dominance screens.

189. Although we are eliminating the exemption from the generation market power analysis for sales into an ISO or RTO with Commission-approved market monitoring and

[185] We remind applicants that they may make appropriate simplifying assumptions that do no not affect the underlying methodologies utilized by the generation market power screens. We expect that once we act on an applicant's generation market power analysis, under which the relevant geographic market is an ISO/RTO, most subsequent applicants will be able to rely on our findings on the market share analysis of the first applicant to support their own applications for market-based rate authority.

mitigation, applicants can incorporate the mitigation they are subject to in ISO/RTO markets as part of their market power analysis. For example, if a market power study showed that an applicant had local market power, the applicant could point to RTO mitigation rules as evidence that this market power has been adequately mitigated. We believe the added protections provided in structured markets with market monitoring and mitigation generally result in a market where prices are transparent and attempts to exercise of market power would be sufficiently mitigated.

190. In contrast to other markets, markets with Commission-approved market monitoring and mitigation undertake daily and hourly oversight of seller's pricing behavior to ensure, consistent with clearly established Commission approved rules, that prices do not exceed competitive levels. The evaluation and mitigation of market power in markets with Commission-approved market monitoring and mitigation does not depend upon a snapshot test of the size or concentration of ownership of any seller. Such mitigation is typically implemented in real-time and in advance of any market price impact. All sellers' interactions with the market are required to comply with pre-determined bidding restrictions and Commission-approved rules and mitigation protocols. High locational prices or binding transmission constraints can trigger the market monitor into further examining the market outcome.

191. Further, in markets with Commission-approved market monitoring and mitigation, electricity products are often broken up into tradable components with distinct markets such as energy, installed capacity and various ancillary services (some of which have forward elements such as forward reserves). The creation of fungible tradable electricity products (e.g., installed capacity and energy balancing) facilitates the development of a competitive market for each of the subcomponents. Thus, a seller can market its energy in such markets and at the same time sell its installed capacity in a separate and distinct capacity market. The segmentation of power into individually-traded components (i.e., energy, installed capacity, ancillary services) permits more competition in markets with Commission-approved market monitoring and mitigation and diffuses any generation market power of sellers compared to more physically-oriented markets, such as traditional vertically-integrated markets, where generation ownership typically concentrates all of these products in the single sale of long-term firm physical power. This segmentation of power into individually-traded components allows for competitive trade in each product market and allows the market monitor to mitigate market power in

each of these product markets separately in the spot market in the event market power would otherwise result in a non-competitive outcome.[186]

F. Native Load Protections

192. This order protects native load customers in several important respects. First, it ensures that when utilities purchase power in wholesale markets they will be able to do so at just and reasonable rates – whether they are cost-based or market-based. Thus, this order protects utilities purchasing in wholesale markets from having to buy power at excessive rates from suppliers with market power. This protection extends to the native load customers of all purchasers in wholesale markets – including native load customers served by cooperatives, municipal utilities and investor-owned utilities. Second, under both screens, utilities that apply for market-based rate authorization do not have to count their generation committed to operating reserves or a reasonable proxy of the amount of generation that is committed to serving their native load customers. Thus, in their capacity as sellers in wholesale markets, explicit recognition is given to utilities' native load obligations and reliability needs. Third, if a utility is found to have market power and it is thus not allowed to sell at market-based rates, the native load customers of that utility are protected by virtue of the fact that the rates adopted to replace the market-based rates will be just and reasonable and based on the utility's costs. Finally, this order protects native load customers by providing greater transparency into how utilities with market power derive the rates they charge at wholesale, so that retail regulators can be sure that the utilities they regulate are flowing through the appropriate portion of revenues from wholesale markets into retail rates.

G. Legal Authority

193. Several entities argue that the Commission erred by replacing the hub-and-spoke analysis with the interim SMA through case-by-case adjudication, rather than through a formal notice-and-comment rulemaking.[187] Citing to the Administrative Procedure

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[186] Of course, safeguards such as the Behavioral Rules for market-based rates, the Commission's ability to revisit grants of market-based rate authority, and FPA section 206 complaints by buyers exist in all markets. While these safeguards provide an important check on market abuses, they are different from the daily and hourly oversight of ISO/RTO cleared transactions in ISO/RTO markets.

[187] See, e.g., Request for Rehearing of AEP at 8-21, Entergy at 2-13, Southern Companies at 7, 17-28, EEI and Alliance at 7-12, Alabama Commission at P 2-4, Florida (continued)

Act,[188] these parties allege that the Commission is required to promulgate any new market power test, including an interim test, through a formal notice-and-comment rulemaking, rather than through case-by-case adjudication. They note that the Commission relied on formal rulemakings in promulgating other major new policies, including Order Nos. 888,[189] 889[190] and 2000.[191] They argue that the SMA fits the statutory definition of a "substantive rule of general applicability" that, by statute, must be issued through a formal rulemaking since it compels significant general obligations on the entire regulated industry and effects major changes in existing policy. The parties allege that failure to meet the SMA threshold determination of generation market power results in substantial effects, including the potential loss of market-based rate authority

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Commission at 1-6, Mississippi Commission at 3-4, Orion at 3-4, PacifiCorp at 3-4, Puget Sound and Avista at 5; see also October 2002 Comments of FirstEnergy at 4, 6-7, Allegheny at 5, 7, and Rayburn at 13.

[188] 5 U.S.C. § 705 (2000).

[189] 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 Fed. Reg. 21,540 (May 10, 1996), FERC Stats. & Regs., Regulations Preambles, January 1991 – June 1996 ¶ 31,036 (1996), order on reh'g, Order No. 888-A, 62 Fed. Reg., 12,274 (March 4, 1997), FERC Stats. & Regs., Regulations Preambles, July 1996-December 2001 ¶ 31,048 (1997), 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, et al. v. FERC, 225 F.3d 667 (D.C. Cir. 2002), aff'd sub nom. New York v. FERC, 535 U.S. 1 (2002).

[190] Open Access Same-Time Information System and Standards of Conduct, Order No. 889, 61 Fed. Reg. 21,737 (1996), FERC Stats. & Regs., Regulations Preambles, July 1996-December 2001 ¶ 31,035 (1996), order on reh'g, Order No. 889-A, 62 Fed. Reg. 12,484 (1997), FERC Stats. & Regs., Regulations Preambles, July 1996-December 2001 ¶ 31,049 (1997), order on reh'g, Order No. 889-B, 81 FERC ¶ 61,253 (1997).

[191] Regional Transmission Organizations, FERC Stats. & Regs. ¶ 31,089 at 30,993 (1999), 65 Fed. Reg. 810 (2000) (Order No. 2000), order on reh'g, Order No. 2000-A, FERC Stats. & Regs.¶ 30,092, 65 Fed. Reg. 12,088 (2000), aff'd, Public Utility District No. 1 v. FERC, 272 F.3d 607 (D.C. Cir. 2001).

and the obligation to implement mitigation measures to avoid such loss, all of which are reasons for using a formal rulemaking.

194. Some parties also allege that their due process rights were violated when the Commission first imposed the new generation market power screen in the SMA Order. They particularly laid claim to their right to be heard before a new substantive policy is applied to them. They argue that they have not been afforded even a paper hearing and that they will experience material loss, through either the loss of market-based rate authority or the imposition of mitigation measures. Entergy notes that the rights of notice, to be heard, and to respond to evidence apply both to rulemakings and to case-by-case adjudication and are particularly important when a new standard is at issue.[192] The parties attack the Commission's use of evidence in the SMA Order, alleging that the Commission did not identify the key data it relied on, other than stating that it used data from Resource Data International, Inc. and the companies' latest Form No. 1.[193] Not only is this improper reliance on material non-record facts, they argue, it also unjustly prevents them from rebutting the Commission's findings and conclusions.[194]

195. Southern Companies and AEP also claim that the Commission's application of the SMA to only a few companies, who had the misfortune of having three-year market power reviews pending before the Commission, is discriminatory since other companies who might also fail the SMA are unaffected and may continue to charge market-based rates without implementing any mitigation measures.[195]

196. Southern Companies also alleges that there has been an unconstitutional "taking" of its property without due compensation through the allegedly "required" relinquishment of control of its OASIS and the "forced sale of power" on the spot market at prices other than "fair market" rates.[196] It alleges that one effect of the SMA Order is to regulate its generating facilities by ordering it to buy and sell power to others, which is unlawful

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[192] See Request for Rehearing of Entergy at 9-13.

[193] See, e.g., Request for Rehearing of AEP at 15-17; cf. Southern Companies at 23-25, Entergy at 29-30.

[194] See, e.g., Request for Rehearing of AEP at 15-17.

[195] See Request for Rehearing of AEP at 18-21, Southern Companies at 23.

[196] See Request for Rehearing of Southern Companies at 28-32.

since the Commission lacks any statutory authority over any generating facilities. Other commenters also argue that the Commission has no authority under the FPA to require purchases and sales.[197]

197. AEP, Entergy, and Southern Companies claim that the Commission's actions in the SMA Order are not justified by either section 205 or section 206.[198] They argue that the three-year reviews are only reports, not tariff filings submitted under section 205, and thus the Commission cannot modify them absent the commencement of a formal 206 proceeding (which would include the right to file an answer) and appropriate section 206 findings as to the unjustness and unreasonableness of the existing rate schedule, neither of which happened. AEP points out that the Commission clearly did not regard its three-year filing as a section 205 application, since it did not act on the filing for over a year, a particularly egregious delay considering the Commission now demands compliance with the mitigation measures in place in such a short time frame. PSEG Companies urges the Commission to move forward in establishing a generic proceeding to evaluate whether the SMA, or some other test, is appropriate to evaluate the ability to exercise market power.[199]

Commission Determination

198. The challenges to the Commission's legal authority center on claims that the Commission erred by failing to proceed through a notice and comment rulemaking; by applying the SMA to AEP, Entergy, and Southern Companies without giving those utilities an opportunity to be heard and to respond; and by imposing mitigation measures that exceed the Commission's authority to ensure that rates for wholesale sales are just and reasonable. All of these arguments have effectively been rendered moot by the actions that the Commission has taken since the issuance of the SMA Order and in this proceeding.

199. As an initial matter, we note that the Commission is not limited to notice and comment rulemaking in developing policy. Agencies generally are permitted

[197] See Request for Rehearing of Alabama Commision at P 4, Southern Companies at 33-34, Xcel at 4.

[198] See Request for Rehearing of AEP at 8-11, Entergy at 13 n.10, Southern Companies at 20-21.

[199] October 2002 Comments of PSEG Companies at 4.

considerable discretion to choose whether to proceed by rulemaking or by adjudication.[200] Our decision to establish new policy in the context of case-specific proceedings is clearly within our authority.

200. In response to the argument that the three-year market-based rate review filings are only reports and not tariff filings under section 205, and that the Commission may not modify market-based rate authorizations without commencement of a formal section 206 proceeding, we note that public utilities filing three-year reviews make those filings pursuant to a condition placed on the Commission's initial authorization of market-based rates under section 205. The filings provide the Commission with the ability to monitor the market power situation and assure that the originally approved rates remain within a zone of reasonableness, consistent with our obligation under the FPA.[201] In this particular case, the Commission made the requisite findings that its generation market power analysis could no longer be relied upon to assure just and reasonable rates and that a new analysis needed to be applied for future market-based rates of these companies, as well as those of other jurisdictional sellers. Even if the Commission were required to commence a section 206 proceeding, as AEP, Entergy, and Southern Companies suggest, the Commission has in any event made the requisite findings and provided sufficient due process to change public utilities' rates prospectively if they do not meet the new standards set forth in our orders.

201. Nevertheless, in light of the concerns on rehearing concerning whether Commission action on three-year market-based rate reviews is undertaken pursuant to section 205 or 206, to avoid confusion, in the future the Commission will institute a section 206 proceeding where the applicant in a three-year market-based rate review proceeding is found to have failed either of the new generation market power screens. Failure of a screen will provide the basis for instituting a section 206 proceeding and will establish a rebuttable presumption of market power in the section 206 proceeding.

202. The Commission believes that it has provided the public with ample notice, rights to be heard, and rights to respond to evidence in this proceeding. Subsequent to the issuance of the SMA Order, the Commission has implemented a comprehensive process

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[200] See Order Seeking Comments on Proposed Revisions to Market-Based Rate Tariffs and Authorizations, 103 FERC ¶ 61,349 at P 51 (2003).

[201] Moreover, in its initial authorization of market-based rates under section 205, the Commission reserves the right to require an updated market analysis at any time.

to provide an opportunity for all interested persons to submit comments and to provide input to the Commission as to possible modifications of the interim generation market power analysis adopted in the SMA Order and related price mitigation. The Commission deferred the date by which AEP, Entergy, and Southern Companies, or any other public utilities, must implement the mitigation for spot market energy sales set forth in section II.E of the SMA Order, and announced its intention to hold a technical conference open to all interested entities, prior to its consideration of the rehearing requests. On August 23, 2002, we issued a notice establishing the proceeding in Docket No. PL02-8-000 to give all interested persons an opportunity to submit written comments regarding the SMA and related mitigation measures. Numerous entities submitted comments. The Commission issued a notice of technical conference that included a Staff Paper that identified possible modifications or alternatives to both the SMA and price mitigation measures. We invited all interested persons to submit written comments on the Staff Paper. Many persons filed comments in response. We heard from representatives throughout the industry at the technical conference held at the FERC offices on January 13-14, 2004; and after the technical conference, provided an opportunity for all interested persons to file supplemental comments. Many more comments were received. Therefore, the Commission has provided multiple rounds of notice and opportunity for all interested person to file comments in these proceedings. We have given careful consideration to the numerous comments received by industry participants in these proceedings, and adopted numerous modifications to the generation market power analysis and related mitigation based on those comments. As a result, we conclude that all entities have been given a full opportunity to be heard. Accordingly, we dismiss as moot the due process arguments raised on rehearing.

203. We also dismiss as moot Southern Companies' allegation that there has been an unconstitutional "taking" of its property without due compensation through the allegedly "required" relinquishment of control of its OASIS and the "forced sale of power" on the spot market at prices other than "fair market" rates, given the Commission's resolution of these issues on rehearing. As discussed above, the Commission is granting rehearing of its decision in the SMA Order directing Southern Companies and Entergy to employ an independent third party to operate and administer its OASIS site. We will consider the issue of whether there is a need to require a change of control of transmission facilities in other proceedings, as may be appropriate. Further, the Commission has decided to replace the spot market mitigation measures imposed in the SMA Order with other mitigation options.[202]

[202] On this basis, commenters' arguments that the Commission has no authority under the FPA to require purchases and sales are moot as well.

204. Further, we dismiss as moot the arguments raised on rehearing that, by announcing the SMA in an order addressing the three-year market-based rate reviews of AEP, Entergy, and Southern Companies, and applying the SMA to those companies in that order, the Commission discriminated against those companies. In this order we are not making any findings regarding whether a particular entity (i.e., AEP, Entergy, Southern Companies) passes the interim screens, as modified herein, nor are we imposing in this order mitigation on any entity. Instead, consistent with the implementation process set forth below, each company will have an opportunity to demonstrate that it satisfies our generation market power concerns. Moreover, no mitigation will be imposed (including default cost-based rates) until there has been a Commission order making a definitive finding that the applicant has market power or the applicant accepts a presumption of market power and so mitigates.

205. Further, we will apply these same generation market power screens and, where appropriate, mitigation measures to all pending and future market-based rate applications, including three-year market-based rate reviews, until such time as a long-term generation market power analysis may be adopted pursuant to the rulemaking proceeding that the Commission is instituting in a companion order that will address all aspects of the Commission's program to review requests for market-based rate authority by electric public utilities. On this basis, we have fully addressed arguments raised on rehearing that the Commission is applying the tests in a discriminatory manner.

H. Implementation Process

206. We are not making any findings at this time, in connection with the three-year market-based rate review filings of AEP, Entergy, and Southern Companies that are the subject of this rehearing, as to whether those applicants pass the interim screens, as modified herein. Nor are we imposing in this order mitigation on those applicants. Instead, each of these companies will have 60 days from the date of issuance of this order to make a filing with the Commission submitting its generation market power analyses pursuant to the two indicative screens (pivotal supplier and market share) adopted in this order. Thus, each company will have an opportunity to demonstrate that it passes the interim screens.

207. Each of these revised filings will be noticed in the Federal Register, with an opportunity for comment by interested parties. Following Commission review of these analyses, the Commission will issue an order addressing the filings on the indicative screens. Applicants that do not pass the two indicative screens (thus creating a rebuttable presumption of market power) will have the option of presenting a more thorough analysis using the Delivered Price Test. In the alternative, each of these companies may

proceed directly to mitigation. Should they choose this route, each company will have the option of proposing specific mitigation tailored to its particular circumstances sufficient to alleviate any market power concerns, or adopting default rates, as set forth herein.

208. An applicant that fails the initial screens will have 60 days from the date of issuance of an order finding a screen failure to: (1) file a Delivered Price Test analysis (if it so chooses); (2) file a mitigation proposal tailored to its particular circumstances that would eliminate the ability to exercise market power; and/or (3) inform the Commission that it will adopt the default cost-based rates discussed herein or propose other cost-based rates and submit cost support for such rates.[203] As discussed below, this proceeding will be pursuant to section 206 of the FPA.

209. Failure to pass either of the indicative screens (which, as noted above, creates a rebuttable presumption of market power) will constitute a prima facie showing that the rates charged by the applicant pursuant to its market-based rate authority may have become unjust and unreasonable and that continuation of the applicant's market-based rate authority may no longer be just and reasonable. Accordingly, in the order addressing the applicant's failure of the indicative screen(s), the Commission will institute a section 206 proceeding to examine whether the applicant may continue to charge market-based rates. That order will establish a refund effective date pursuant to the provisions of section 206. The floor for any refunds ultimately ordered would be based on the default rates set forth in this order or, if applicable, any case-specific cost-based rates proposed by the applicant and accepted by the Commission for a particular application. Thus, the Commission's review of the applicant's Delivered Price Test analysis (if one is submitted) and its review of a case-specific mitigation proposal (if one is submitted) will proceed pursuant to section 206.

210. Following the Commission's review of the Delivered Price Test analysis (if one is submitted), the Commission will issue a subsequent order making a definitive finding as to whether the applicant has market power. No mitigation will be imposed (including default rates) until there has been a Commission order making a definitive finding that

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[203] If the applicant files a mitigation proposal that is not sufficient to mitigate market power, the Commission will set the just and reasonable rate at the default rate unless the applicant has proposed a different cost-based rate that is just and reasonable. In either case, the applicant will have to provide cost support for the rate.

the applicant has market power or, where the applicant accepts a presumption of market power, an order is issued addressing whether default cost-based rates or case-specific cost-based rates are to be applied.

211. The Commission will apply these same implementation procedures to other applicants with pending or future market-based rate applications, including three-year market-based rate reviews, pending the completion of the market-based rate rulemaking that we discuss above.[204]

The Commission orders:

(A) The Commission grants rehearing of the SMA Order to the extent that it modifies the generation market power analysis and mitigation policy set forth in the SMA Order, as discussed in the body of this order.

(B) The Commission dismisses as moot the arguments raised on rehearing challenging the Commission's legal authority, as discussed in the body of this order.

(C) AEP, Entergy and Southern Companies are directed to file within 60 days of the date of issuance of this order generation market power analyses pursuant to the two indicative screens (pivotal supplier and market share), as discussed in the body of this order.

By the Commission.

(S E A L)

Linda Mitry,
Acting Secretary.

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[204] The Commission intends to issue a subsequent order addressing the implementation process for pending three-year market-based rate reviews as well as pending applications for initial market-based rate authority.

Appendix A
Motions to Intervene Out of Time, Requests for Rehearing, etc.

Alabama Electric Cooperative, Inc. (AEC)	Motion to intervene out-of-time
Alabama Public Service Commission (Alabama Commission)	Notice of intervention, or in the alternative, motion to intervene out-of-time; Motion to withdraw order or, in the alternative, motion for stay and request for rehearing
AEP	Request for rehearing, motions to extend or stay the compliance deadline, and request for expedited action
American Public Power Association (APPA)	Motion to intervene, request for partial consolidation, request for rulemaking and comments
Arizona Electric Power Cooperative, Inc. (AEPCO)	Motion for late intervention, request for rehearing and comments
Avista Energy (Avista Energy)	Motion to intervene out-of-time and request for rehearing
California Electricity Oversight Board (CEOB)	Motion to intervene out-of-time and request for rehearing and clarification
Calpine Corporation (Calpine)	Motion to intervene out-of-time and comments
Duke Energy North America, LLC and Duke Energy Trading & Marketing, LLC (collectively, Duke Energy)	Motion to intervene out-of-time and request for rehearing
Duke Power Company (Duke Power)	Motion to Intervene out-of-time and request for rehearing
Edison Electric Institute and Alliance of Energy Suppliers (collectively, EEI)	Motion to Intervene, Motion to Vacate, or in the alternative to stay and Request for Rulemaking; Comments[205]
El Paso Merchant Energy, L.P.; Berkshire Power Company, LLC; BIV Generation Company LLC; Camden Cogen; Cedar Brakes I, LLC; Cedar Brakes II, LLC; Cedar Brakes III, LLC; Colorado Power	Motion to intervene out-of-time and request for rehearing

[205] EEI filed additional comments on January 4, 2002.

Partners; Dartmouth Power Associates LP; Eagle Point Cogeneration Partnership; Fulton Cogeneration Associates; L.P.; Milford Power Company, LLC; Mohawk River Funding III, LLC; Newark Bay Cogeneration Partnership, LP; Poquonock River Funding, LLC; and San Joaquin Cogen Limited (collectively, El Paso)	
Electricity Consumers Resource Council (ELCON)	Motion to Intervene and Comments
Electric Power Supply Association (EPSA)	Motion to Intervene out-of-time and request for rehearing
Entergy	Motion for Extension of Time; Request for Rehearing and Emergency Motion for Extension of Time, or in the alternative, Stay Pending Rehearing; Workpapers Supporting J. Stephen Henderson
FirstEnergy Corp. (FirstEnergy)	Motion for Leave to Intervene out-of-time; Request for Rehearing
Florida Public Service Commission (Florida Commission)	Notice of Intervention and Motion for Stay and Request for Rehearing
FPL Energy, LLC (FPLE)	Motion to intervene and comments
Louisiana Public Service Commission (Louisiana Commission)	Notice of Intervention and Request for Rehearing
Lott, Senator Trent	Comments
Mississippi Public Service Commission (Mississippi Commission)	Motion to intervene, request for rehearing & request for stay
Monongahela Power Company, Potomac Edison Company, West Penn Power Company and Allegheny Energy Supply Company, LLC (Allegheny)	Motion to intervene out-of-time and request for rehearing
National Rural Electric Cooperative Association (NRECA)	Motion to intervene out-of-time; Request for Rehearing and Clarification

New Mexico and Rhode Island Offices of Attorney General and the Rhode Island Division of Public Utilities and Carriers[206]	Comments; Reply Comments (filed on February 5, 2002)
NSTAR Electric & Gas Corporation (NSTAR)	Motion to Intervene out-of-time and comments
Nordstar Market Consultants (Nordstar)	Comments (no motion to intervene)
Oklahoma Corporation Commission (Oklahoma Commission)	Motion of Intervention [207]
Oklahoma Municipal Power Authority (OMPA)	Reply to AEP's Motion to Extend or Stay the Compliance Deadline
Orion Power Midwest, L.P. and Orion Power New York GP, Inc. (collectively, Orion)	Motion to Intervene out-of-time; Request for Rehearing and Clarification
PacifiCorp	Motion for Late Intervention and Request for Rehearing
Puget Sound Energy, Inc., and Avista Corporation (collectively, Puget/Avista)	Motion to intervene out-of-time; Request for Rehearing and Clarification
Attorney General of the State of Rhode Island and Rhode Island Division of Public Utilities (collectively, Rhode Island)	Motion to intervene out-of-time and comments
City and County of San Francisco (San Francisco)	Motion to Intervene Out-of-Time; Request for Clarification and Rehearing and Comments
Southern Companies	Request for Rehearing and request for stay
Xcel Energy Services, Inc. and Xcel Operating Companies (The Xcel Operating Companies are: Public Service Company of Colorado, Southwestern Public Service Company, Northern States Power Company, and Northern States Power Company (Wisconsin)) (collectively, Xcel)	Motion to intervene and request for rehearing

[206] On December 7, 2001, the Attorney General of the State of Rhode Island and Rhode Island Division of Public Utilities (collectively, Rhode Island) filed a motion to intervene,

[207] Oklahoma Commission filed separate motions to intervene in Docket Nos. ER96-2495 and ER91-569

Appendix B
PL02-8-000 Comments

AEP
Allegheny
APPA and Transmission Access Policy Study Group (APPA/TAPS)[208]
California Independent System Operator (CAISO)
California Public Utilities Commission (California Commission)
Calpine
Carolina Power & Light Company, Florida Power Corporation and WPS Resources Corporation (collectively, CP&L)
Citizen Power
Connecticut Department of Public Utility Control (Connecticut PUC)
Dominion Resources, Inc. (Dominion)
Duke Energy Corporation (Duke Energy)
EEI
ELCON
Entergy
EPSA
Exelon Corporation (Exelon)[209]
FirstEnergy
Florida Phosphate Council and Florida Industrial Cogeneration Association (collectively, Florida Industrials)
Gerdau Ameristeel, Nucor Steel, SMI Steel and Steel Dynamics (collectively, Steel Producers)
LG&E Energy Corp. (LG&E)
Louisiana Commission
Mississippi Commission
NRECA
NSTAR
Old Dominion Electric Cooperative (Old Dominion)

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[208] APPA/TAPS also filed a motion for acceptance of late-filed comments.

[209] Exelon also filed a motion to accept comments one day late.

Pennsylvania Office of Consumer Advocate, Maryland Office of People's Counsel and District of Columbia Office of the People's Counsel (collectively, Joint Consumer Advocates)[210]
PSEG Energy Resources & Trade LLC and PSEG Power LLC (collectively, PSEG)
Rayburn Country Electric Cooperative, Inc. (Rayburn)
Reliant Resources, Inc. (Reliant)
Sacramento Municipal Utility District (SMUD)
Seminole Electric Cooperative, Inc. (Seminole)
Southern Companies
TECO Energy, Inc. (TECO)
Utilities Commission, City of New Smyrna Beach, Florida (New Smyrna Beach Commission)
Williams Energy Marketing & Trading Company (Williams)
Xcel

[210] Joint Consumer Advocates also filed a motion to accept comments one day late.

Appendix C
Comments on Staff Paper

AEP
Alliant Energy Corporate Services, Inc. (Alliant)
APPA/TAPS
Bonneville Power Administration (BPA)
California Commission
Carnegie Mellon Electricity Industry Center (Carnegie Mellon)
Carolina Power & Light Company and Florida Power Corporation (collectively, Progress)
CEOB
Cinergy Services, Inc. (Cinergy)
Delaware Municipal Electric Corporation, Inc. (DMEC)
Dominion
Duke Energy Corporation (Duke Energy)
Edison Mission Energy and Midwest Generation, L.L.C. (EME)
EEI
ELCON
Entergy
Exelon
FirstEnergy
Joint Consumer Advocates
Louisiana Commission
New York Independent System Operator, Inc. (NYISO)[211]
New York Transmission Owners[212]
NRECA
PacifiCorp
PSEG
Reliant

[211] NYISO also filed a motion to intervene.

[212] Central Hudson Gas & Electric Corporation; Consolidated Edison Company of New York, Inc.; LIPA; New York Power Authority; New York State Electric & Gas Corporation; Rochester Gas and Electric Corporation; Orange and Rockland Utilities, Inc.; and Niagara Mohawk Power Corporation, a National Grid Company (collectively, New York Transmission Owners).

Seminole
Southern Companies
Tractebel Energy Marketing, Inc. (Tractebel)
Wisconsin Public Service Corporation, WPS Power Development Inc., and WPS Energy Services Inc. (collectively, WPS Companies)
Xcel

Appendix D
Post-Technical Conference Comments

AEP
APPA/TAPS
Arkansas Public Service Commission (Arkansas Commission)
BPA
CEOB
Carolina Power & Light Company (CP&L)
Duke
East Texas Cooperatives (ETC)[213]
EME
EEI
EPSA
Exelon
InterGen Services, Inc. (InterGen)
Louisiana Commission
Montana Consumer Counsel (MCC)
New Mexico Office of Attorney General, Colorado Office of Consumer Counsel and Utah Committee of Consumer Service (collectively, New Mexico/Colorado/Utah)
New York Independent System Operator, Inc.; ISO New England Inc. and PJM Interconnection, LLC (collectively, Northeast System Operators)
North Carolina Electric Membership Corporation (NCEMC)
NRECA
PacifiCorp
PSEG
Puget Sound Energy, Inc. (Puget)
Reliant
SMUD
Southern Companies
Southern California Edison Company (SCE)
Steel Producers
The Brattle Group
Tractebel

[213] East Texas Electric Cooperative, Inc.; Northeast Texas Electric Cooperative, Inc.; Sam Rayburn G&T Electric Cooperative, Inc.; Tex-La Electric Cooperative of Texas, Inc. (collectively, East Texas Cooperatives).

Transmission Dependent Utility Systems (TDU Systems)
WPS Companies [this filing also includes Upper Peninsula Power Company]
Xcel

Appendix E

We will set the amount of supply that can reach the relevant market as uncommitted capacity limited by the simultaneous transmission import capability. In order to provide transparency, the following supporting data/documents are required to be provided by any applicant, including its affiliate, as applicable, that is also a transmission provider (TP).

Simultaneous Import Capability for the transmission provider's control area market (study area) is a total transfer capability calculation that estimates the simultaneous imports that could have historically been utilized by remote resources. The import capability calculations considers both the TP's tariff as a basis and the transmission reliability margins existing on the applicant's flow gates during each seasonal peak being studied. The TP applicant is required to treat the TP control area as a single area ("study area") and treat the first-tier markets (single aggregated control area) as a single area (representing the surrounding/available control areas to import power from). The import capability of the study area is the simultaneous transfer limit from the aggregated first-tier market area into the study area. The power flow cases should represent the TPs tariff provisions, the operational practices historically used, all reliability margins (TRM, CBM, counter flow, generating operating limits, operating reserves) existing during each peak, and all firm/network reservations held by applicant/affiliate resources during the most recent seasonal peaks. The applicant shall also apply an aggregation of all internal/external contingency facilities and all monitored/limiting facilities that were used historically to approximate area-area transmission availability (TTC/ATC limits available to non-affiliated resources). In addition, the applicant shall scale up available generation in the exporting (aggregated first tier areas) and scale down the study area resources according to the same methods used historically in assessing available transmission for non-affiliate resources. Therefore, this calculation represents an estimate of the total import capability available to remote resources.

Simultaneous Import Capability for the TP's first tier markets The approach to approximate this transmission import capability is slightly different than the approach used to determine import capability for the TP applicant study area. For each first tier market, the "benchmark" seasonal cases are modified by backing out the first tier market into a separate area to be studied. Other directly interconnected first tier control areas are then aggregated together with original applicant study area. Import capability (aggregate to first tier market being studied) into the first tier market is approximated using the same techniques as used for the TP's study area. If the applicant fails the generation market power study when centered on any of its first tier markets, another approximation may be submitted for Commission consideration. That study would incorporate interconnected second-tier control areas into the previously aggregate control areas described above. If this option is utilized, the applicant may get additional information (TRM, CBM, counter flow, generating operating limits, operating reserves) to complete the study.

Power Flow Benchmark Cases of Historical Monthly Peaks. In addition, we will require TP applicants to submit power flow benchmark cases (with supporting data) used in calculating total simultaneous import capability for each of the previous four seasonal peaks. The cases should reasonably simulate the historical conditions that were present including; facility/line deratings used to maintain capacity benefit margins (CBM) and transmission reliability (TRM/CBM), actual unit dispatch used to fulfill network and firm reservation obligation, the actual peak demand, generator operating limits opposed on all resources in real time, other limits/constraints imposed by the TP during the season peaks. Non-affiliate, non-network firm contracts should not be modeled in order to simulate non-affiliate transmission access to the TP's home control area. The TP applicant is required to provide documentation listing all historical assumptions used to develop each historical seasonal benchmark case. Additionally, the applicant should include the referenced base case, regional or MMG (NERC planning loadflow case) case was used as a starting point.

Appendix F

A staff summary regarding the steps in the Delivered Price Test is as follows:[214]

(1) choose a destination market:

(2) choose the season/load levels to analyze: Super-Peak, Peak, and Off-Peak, for winter, shoulder and summer periods, and an extreme Summer Peak, for a total of ten season/load levels;

(3) choose a market price to correspond to each season/load period;[215]

(4) determine the suppliers that could sell into the destination market at a price less than or equal to 5% over the market price. That is, determine which generators have costs less than or equal to 1.05 times the market price,[216] and;

(5) allocate transmission availability.[217]

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[214] For a complete description of the Delivered Price Test and its requirements, see Appendix A of the Merger Policy Statement and Order No. 642.

[215] This is one of the critical parameters. It is usually based on a combination of observed prices from the trade press or RTO/ISO data and system lambdas. Since the results of the Delivered Price Test depend critically on the assumed market price, applicants are required to provide tests of the sensitivity of their results to changes in the market price

[216] The costs include running costs, transmission charges, O&M and environmental adders.

[217] Since there is usually more generation capable of supplying a destination market than available transmission, access to the critical interfaces must be allocated. Either an economic allocation (least cost) or pro-rata (shares based on share of supply) can be used. Simultaneous transfer limits are also considered. For example, suppose the Available Transfer Capability (ATC) on one line is 500 MW and the ATC on another line is 600 MW. If, for physical reasons, the two lines together can only handle 900 MW, this constraint is imposed in the Delivered Price Test.

Next, calculate the number of megawatts of all the suppliers that can compete in the destination market, given their costs and the transmission availability. This number is called their "economic capacity". In order to calculate available economic capacity, subtract the supplier's native load obligation and adjust transmission availability accordingly.

Appendix G

Unless submitting as part of their pivotal supplier and market share screens, a streamlined application, Applicants should provide the minimum data listed below including appropriate support and work papers:

Home Control Area:

For each screen, as applicable, include applicant's installed capacity (nameplate capacity) plus long-term firm purchases, separately stated and uncommitted capacity. Provide work papers for all reductions to installed capacity (i.e., native load obligations, planned outages, reserve requirements, long-term firm non-requirement sales). Provide a similar analysis for non-affiliate capacity (these amounts can be aggregated provided any applicant-owned generation is separately stated). Also, include the control area's peak demand (annual and seasonal amounts as discussed herein). Where applicable, include simultaneous import capability studies.

First-Tier Markets:

For each screen, as applicable, identify any applicant-owned generation and provide installed and uncommitted capacity as discussed above. Provide a similar analysis for non-affiliate capacity (these amounts can be aggregated provided any applicant-owned generation is separately stated). Also, include the control area's peak demand (annual and seasonal amounts as discussed herein). Where applicable, include simultaneous import capability studies.

Applicants should provide documentation to all data used, and list all assumptions relied upon in all figures derived by the applicant.