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. ER96-2495-018, ER97-4143-006, ER97-1238-013, ER98-2075-012, ER98-542-008 (Not consolidated)
Entergy Services, Inc.	Docket Nos. ER91-569-021
Southern Company Energy Marketing L.P.	Docket Nos. ER97-4166-013
Conference on Supply Margin Assessment	Docket No. PL02-8-001

ORDER ON REHEARING

(Issued July 8, 2004)

Introduction

1. In an order issued on April 14, 2004,[1] the Commission replaced the Supply Margin Assessment (SMA) test announced in the SMA Order[2] with two indicative screens for assessing generation market power and modified the mitigation announced in the SMA Order. The Commission explained that the generation market power screens adopted in the April 14 Order are for interim purposes only. Concurrently with the issuance of the April 14 Order, the Commission issued 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.[3]

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[1] AEP Power Marketing, Inc., *et al.*, 107 FERC ¶ 61,018 (2004) (April 14 Order).

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

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

2. On May 13, 2004, the Commission issued an Order Implementing New Generation Market Power Analysis And Mitigation Procedures[4] addressing the procedures for implementing the new interim generation market power analysis and mitigation policy announced in the Commission's April 14 Order. Among other things, the May 13 Order directs all applicants with three-year market-based reviews pending before the Commission on or before May 13, 2004, to file their revised generation market power analysis in accordance with the schedule contained in Appendix A of the May 13 Order.

3. On June 7, 2004, the Commission issued an Order Granting Rehearing For Further Consideration And Notice Granting Extension Of Time,[5] granting an extension of 30 days from the issuance of the instant order for the submission of revised generation market power analyses in compliance with the April 14 Order.

4. As we recognized in the April 14 Order, in acting on rehearing of the SMA Order, we faced the very difficult task of determining how to achieve a balanced interim approach to assessing and mitigating generation market power. We had to take into account the concerns of all industry participants (often conflicting) and, at the same time, ensure that we were meeting our responsibilities under the Federal Power Act (FPA) to ensure that wholesale rates remain just and reasonable.[6] We concluded that an approach that 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 adopted in the April 14 Order a policy that provides applicants a number of procedural options, several types of generation market screens, and the option of proposing mitigation tailored to the particular circumstances of the applicant.

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[4] Acadia Power Partners, LLC, *et al.*, 107 FERC ¶ 61,168 (2004) (May 13 Order).

[5] AEP Power Marketing, Inc., *et al.* (Docket No. ER96-2495-018, *et al.*, June 7, 2004) (unpublished order) (June 7 Order).

[6] The Commission provided an extensive process for all interested parties to inform the Commission of their views. In addition to requests for rehearing and comments on the SMA Order, the Commission solicited an additional three rounds of comments, issued a Staff Paper that set forth positions and sought comment on specific questions, held a two-day technical conference that featured a variety of presenters from very diverse viewpoints, and invited comments on the issues addressed by the technical conference.

5. On rehearing, numerous entities acknowledge the difficult task the Commission faced in attempting to address the competing recommendations and solutions proposed by commenters in this proceeding, and the extensive effort we undertook to revise, on an interim basis, the generation market power analysis for evaluating market-based rate applications and related mitigation.[7]

6. The requests for rehearing of the April 14 Order continue to evidence the different positions that industry participants have concerning how the Commission should assess generation market power for purposes of the interim generation market power analysis, including whether control areas and certain independent system operators (ISO) or regional transmission organizations (RTO) should constitute the default relevant geographic markets; the appropriate methodology for calculating simultaneous transmission import capability; the appropriate methodology for calculating committed and uncommitted capacity for purposes of performing the indicative screens and the Delivered Price Test; the scope of appropriate mitigation measures for applicants that are found to have market power in generation; and whether the Commission should reinstate its previous blanket exemption from the interim generation market power analysis for sales into ISO/RTO markets with Commission-approved market monitoring and mitigation.[8]

7. The investor-owned utilities that filed for rehearing contend that, on a number of issues, the April 14 Order is too stringent and may fail too many applicants, whereas public power entities and customer advocates argue that on certain issues the order does not go far enough. As discussed in more detail below, although we do not believe that

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[7] *See, e.g.,* Requests for Rehearing of Duke Energy Corporation (Duke) at 1-2; the American Public Power Association and the Transmission Access Policy Study Group (APPA/TAPS) at 1 (Commission serves both buyers and sellers by abandoning the search for a "silver-bullet" screen and instead adopting screens and tests that establish rebuttable presumptions and allow a closer examination of facts; National Rural Electric Cooperative Association (NRECA) at 4 (commending the Commission for its April 14 Order, as it makes substantial improvements to the prior SMA screening regime); Dominion Resources, Inc. (Dominion) at 2 (screens adopted in the April 14 Order are a reasonable interim response in light of the substantial record and conflicting positions).

[8] A number of entities who filed requests for rehearing did not file a motion to intervene in the underlying dockets and, on that basis, are not parties with standing to seek rehearing. 16 U.S.C. § 825l (2000). Nevertheless, we will consider their filings as additional comments and address them on that basis.

rehearing is warranted, we clarify and modify certain instructions for performing the generation market power analysis adopted in the April 14 Order. For example, we clarify the types of data on which applicants and intervenors may rely and clarify that we will allow adjustments in certain circumstances, we clarify a number of issues associated with simultaneous transmission import capability studies, and we clarify the types of firm obligations that may be reflected in the calculation of an applicant's uncommitted capacity. This order benefits customers by improving the assessment and mitigation of generation market power in wholesale markets and, thus, better ensures that prices charged for jurisdictional sales are just and reasonable.

I. Background

8. 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).[9]

9. In the April 14 Order, the Commission adopted an uncommitted pivotal supplier analysis and an uncommitted market share analysis and treated both screens as indicative, rather than definitive, screens of generation market power. Passage of both screens establishes a rebuttable presumption that the applicant does not possess generation market power, while failure of either creates a rebuttable presumption that it does. Applicants and intervenors may, however, rebut the presumption established by the results of the initial screens by submitting a Delivered Price Test and historical data. Alternatively, an applicant may accept the presumption of market power or forego the generation market power analysis altogether and go directly to mitigation. Such an applicant may either file a mitigation proposal tailored to its particular circumstances that would eliminate the ability to exercise market power or inform the Commission that it will adopt the default cost-based rates or propose other cost-based rates.

[9] 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.

II. Analysis

A. Summary of Rehearing Requests and Commission Determinations

10. In response to the April 14 Order, nineteen parties filed requests for rehearing and/or clarification on a wide range of issues. The majority of the comments received focus on clarifying the instructions regarding the application of the April 14 Order's generation market power analysis or criticizing the measures chosen by the Commission in formulating the screens, such as the provisions regarding the default geographic market definition, the calculation of simultaneous transmission import capability, and the proxies used to calculate applicants' committed and uncommitted capacity for the purpose of applying the generation market power analysis.

11. Several parties object to the Commission's decision to use either control areas or certain ISO/RTOs' boundaries as the default relevant geographic market definition. These parties argue that, where there are binding transmission constraints or load pockets, this approach results in an overly broad geographic market definition and thus understates applicants' market power.

12. With respect to simultaneous transmission import capability, a number of parties object to the Commission's instruction that an applicant first allocate simultaneous transmission import capability to its own uncommitted remote generation capacity located in first-tier markets, arguing that this instruction is inconsistent with their Commission-approved Open Access Transmission Tariffs (OATT). Other parties seek clarification regarding the elements used to calculate this measure, for example, arguing for the inclusion of transmission reliability margins and capacity benefit margins.

13. Investor-owned utilities argue that too little native load is deducted from installed capacity, which in turn overstates the market power of traditional utilities. They argue that the proxies used for native load systematically understate committed capacity and overstate uncommitted capacity for both screens. Moreover, they note that the Delivered Price Test's economic capacity analysis does not permit any deduction for native load. As a result of these alleged flaws, they contend that traditional utilities are doomed to fail both the market share analysis and the Delivered Price Test. They also argue that the Commission's methodology overstates the amount of uncommitted capacity by not allowing applicants to deduct, for example, forced outages, "load following" contracts serving retail customers and certain firm contracts.

14. Parties representing public power and cooperative entities, on the other hand, argue that the screens deduct too much native load, which in turn understates market power. These parties contend that the Commission should not permit applicants to deduct for native load at all, as this capacity may also be used to serve the wholesale market. Furthermore, these parties argue that applicants should not be permitted to deduct for long-term firm contracts that are set to expire during the three-year market-based rate authorization period.

15. Parties were sharply divided over the merits of the market share screen. A number of investor-owned utility parties argue that the market share screen is too conservative with the result that it will erroneously fail traditional utilities that lack market power, while other parties contend that the test is too lenient. Investor-owned utility parties argue that the market share screen is an unreliable indicator of market power because, first, market shares are not a meaningful indicator of market power, particularly during off-peak periods. Second, they argue that the 20 percent threshold is either arbitrary or too low and that, in any case, the Commission's methodology for calculating applicants' market shares – which is based on capacity rather than sales and uses an overly conservative native load proxy – overstates traditional utilities' market share. Other parties, however, support the market share screen as an accurate indicator of market power, but urge the Commission to make the test more stringent, for example, by incorporating a measure indicating applicants' ability to engage in coordinated anticompetitive behavior.

16. The investor-owned utility parties argue that the Commission's cost-based default mitigation measures sweep too broadly in terms of geographic or temporal scope and that they do not provide adequate compensation. These parties propose to remedy these defects either by limiting their scope or by developing market-based mitigation measures. On the other hand, a number of other parties argue that the April 14 Order's mitigation measures should go further and that the Commission should impose structural remedies to eliminate the underlying market power instead.

17. The April 14 Order eliminated the SMA Order's blanket exemption from the generation market power analysis for sales into ISO/RTOs with Commission-approved market monitoring and mitigation. A number of parties urge the Commission to reinstate the exemption, arguing that ISO/RTO mitigation measures have in practice proven effective at preventing the abuse of market power. Other parties support the April 14 Order on this point and argue that this exemption is not warranted given that ISO/RTO market rules do not cover significant parts of the market such as bilateral and long-term markets and that the mitigation they do provide has proven to be ineffective.

18. After careful consideration of the rehearing requests, we have determined that rehearing is not warranted. We do not reiterate herein each and every argument raised by parties on rehearing because many are simply a rehashing of previous arguments raised throughout the course of this proceeding and addressed in the April 14 Order. Accordingly, as discussed below, rehearing of the April 14 Order is denied. However, we do provide a number of clarifications of certain aspects of the order.

B. Generation Market Power Analysis

1. Indicative Screens

19. In the April 14 Order, the Commission replaced the single definitive SMA generation market power test and adopted two "indicative" screens for assessing generation market power, failure of which establishes a rebuttable presumption of market power. The pivotal supplier analysis evaluates the potential of an applicant to exercise market power based on the control area market's annual peak demand, while the market share analysis assesses market power on the basis of an applicant's share of the uncommitted capacity during each season.

a. Rehearing Requests

20. On rehearing, several parties commend the Commission's new approach to the evaluation of generation market power, in particular its decision to treat the screens as indicative, rather than definitive, tests of market power.[10] APPA/TAPS praises the Commission for adopting screens that establish a rebuttable presumption, which allows a closer examination of the facts than a definitive test would.[11] The Joint Consumer Advocates applaud the Commission's decision to extend the use of indicative screens to entities operating within ISO/RTOs.[12]

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[10] Requests for Rehearing of Edison Electric Institute (EEI) at 6, NRECA at 4. EEI's request is supported by a number of other investor-owned utility parties, including AEP, Entergy and Southern Companies. *See also* Request for Rehearing of Electric Power Supply Association (EPSA) at 3.

[11] Request for Rehearing of APPA/TAPS at 1.

[12] Request for Rehearing of Pennsylvania Office of Consumer Advocate, Maryland Office of People's Counsel, Ohio Office of Consumer Counsel and Office of People's Counsel for the District of Columbia (collectively, Joint Consumer Advocates) at 1.

21. Southern Companies, however, contends that the screens are in fact more akin to definitive tests than indicative screens because the only way that applicants may rebut the presumption of market power established by their failure of either screen is by passing the Delivered Price Test, which, according to Southern Companies, virtually all traditional utilities are doomed to fail because it does not take into account their native load obligations.[13] Southern Companies argues that applicants should be able to present any type of study or evidence to rebut the presumption of market power in addition to the Delivered Price Test.[14]

22. APPA/TAPS argues that, since the Delivered Price Test is the only additional market power study that the Commission will accept, the Commission should clarify that intervenors may submit a Delivered Price Test and that these intervenor-submitted tests can rebut the presumption established by applicants' passage of the screens. Second, APPA/TAPS proposes that the Commission should allow intervenors to introduce supply curve evidence to assess a seller's ability and incentive to exercise market power based upon the shape and composition of the supply curve and the seller's place on it.[15]

23. Several parties seek clarification regarding the allocation of the burden of proof in market-based rate applications. A number of parties point to an apparent conflict between an applicant's burden of proof under section 205 to demonstrate that its rates are just and reasonable and the April 14 Order's provision that an applicant's failure of either indicative screen will establish a rebuttable presumption that the applicant possesses market power.[16] According to these parties, the April 14 Order suggests that, upon passage of the indicative screens, the burden of proof and persuasion to establish that the

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[13] Request for Rehearing of Southern Companies at 14-15. Southern Companies also contends that the Commission should not characterize applicants that fail the screens as possessing "market power" because, due to the Commission's expertise and authority in the electric industry, a finding of market power in FERC proceedings could be given unintended weight in antitrust proceedings. *Id.* at 10.

[14] *Id.* at 15-17.

[15] Request for Rehearing of APPA/TAPS at 10.

[16] Requests for Rehearing of APPA/TAPS at 10, Calpine Corporation (Calpine) at 7-9, New Mexico Office of Attorney General, Colorado Office of Consumer Counsel, Utah Committee of Consumer Services, Rhode Island Office of Attorney General, and Rhode Island Division of Public Utilities and Carriers (collectively, New Mexico Attorney General, *et al.*) at 6.

applicant has market power shifts to intervenors in violation of section 205. Calpine urges the Commission to clarify that applicants, rather than intervenors, always bear the burden of proving that they lack market power, even if they pass the initial screens.

24. Calpine also seeks clarification regarding the relation between the burden of proof and the rebuttable presumption in the context of the three-year reviews. The April 14 Order states that the Commission will institute a section 206 proceeding where an applicant fails either screen and that their failure establishes a rebuttable presumption of market power. Calpine inquires whether the Commission may simply rely on applicants' failure of the screens in order to carry its burden of proof. Calpine suggests that it would be preferable to treat the three-year reviews as section 205 filings so that the applicant will more clearly bear the burden of proving that it lacks market power and of justifying continuation of its market-based rate authority.[17]

b. Commission Determination

25. Market-based rate authority is not a right. The Commission may grant such authority under the FPA only to applicants who demonstrably lack market power. As discussed in the April 14 Order, the screens are conservatively designed to permit those applicants that clearly do not possess the potential to exercise market power to receive market-based rate authority and to identify the subset of applicants who require closer scrutiny. We recognize that some applicants lacking market power may not pass the screens. For this reason, we have provided applicants and intervenors the opportunity to submit a more robust market power study, *i.e.*, the Delivered Price Test. Applicants and intervenors may also present evidence based on historical wholesale sales or transmission data.[18]

26. We reject Southern Companies' assertion that the indicative screens are in fact more akin to definitive tests. Southern Companies' argument appears to rest on a number of erroneous assumptions. The first is that an applicant's failure of the Delivered Price Test would result in a definitive finding of market power. However, both the April 14 Order and our Revised Filing Requirements Under Part 33 of the Commission's Regulations make clear that applicants have the opportunity to present historical data to

[17] Request for Rehearing of Calpine at 9.

[18] April 14 Order, 107 FERC ¶ 61,018 at P 37 n.11.

refute the results of the Delivered Price Test.[19] Second, Southern Companies erroneously assumes that the Delivered Price Test functions like the initial screens, *i.e.*, failure of either the economic capacity (EC) or available economic capacity (AEC) analyses results in failure of the test as a whole. In fact, neither prong is definitive; the Commission weighs the results of both the EC and the AEC analyses and considers arguments from both applicants and intervenors as to which measure more accurately reflects market conditions. Based on our substantial experience in applying the Delivered Price Test over the past several years, we have found that both analyses are useful indicators of suppliers' potential to exercise market power, and we are unwilling to rely solely on one measure or the other.

27. With respect to Southern Companies' request for guidance concerning the additional types of data applicants may submit to rebut the presumption, we clarify that applicants and intervenors may present historical data including the analyses that they believe most accurately represent market conditions. With respect to forward-looking analyses or studies, however, the Delivered Price Test is the only market power study applicants may submit. The Commission has developed and refined the Delivered Price Test over the past several years and has gained confidence in its results for electricity markets. In the context of individual market-based rate applications, we find that it would be impractical at this time to attempt to base our decisions on the competing predictions of dueling economic models. Since the screens we adopted in the April 14 Order are only interim in nature, and the development of an economic model would take a considerable amount of time, and it is unclear whether such an economic model would yield accurate results, it is appropriate to rely upon the Delivered Price Test which has a proven track record and is readily available. However, the Commission may investigate the possibility of using economic models to measure market power as part of the generic rulemaking proceeding we recently initiated.

28. For the same reasons, we reject Calpine's argument that the April 14 Order gives too much weight to applicants' initial screen analysis. Neither failure nor passage of the screens is definitive; both applicants and intervenors may present historical evidence in order to rebut the presumption of market power. In order to ensure that applicants and intervenors are on a level playing field, we clarify in response to APPA/TAPS' request that intervenors may submit a Delivered Price Test and that such intervenor-submitted Delivered Price Tests can rebut the presumption established by applicants' passage of the

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[19] April 14 Order, 107 FERC ¶ 61,018 at P 37 n.11, 66, 112; Order No. 642, 65 Fed. Reg. 70,983 (2000), FERC Stats. & Regs., Regulations Preambles July 1996-December 2000 ¶ 31,111 at 31,886-87 (2000), *order on reh'g*, Order No. 642-A, 66 Fed. Reg. 16,121 (2001), 94 FERC ¶ 61,289 (2001).

screens. We note that in such cases we will examine the assumptions in the Delivered Price Test that led to different results and consider the merits of each. Furthermore, with respect to the historical data, we clarify that the April 14 Order allows for the introduction of supply curve evidence and analysis, among other things, for consideration.

29. We also reject Calpine's argument that the April 14 Order improperly places the burden of proof on intervenors by providing that passage of both screens creates a rebuttable presumption that an applicant lacks market power. Nothing in the April 14 Order shifts the burden of proof that section 205 imposes on the filing utility.[20] Passing both screens or failing one merely establishes a rebuttable presumption.[21] To challenge an applicant who passes both screens, the intervenor need not conclusively prove that the applicant possesses market power. Rather, the intervenor need only meet a "burden of going forward" with evidence that rebuts the results of the screens.[22] At that point, the burden of going forward would revert back to the applicant to prove that it lacks market power.

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[20] *Cf.* Generic Determination of Rate of Return on Common Equity for Electric Utilities, Order No. 389-A, 29 FERC ¶ 61,223 at 61,458 (1984) (concluding that rebuttable presumption that a rate of return based on a benchmark is just and reasonable does not shift ultimate burden of proof imposed by Federal Power Act).

[21] *See* Pennzoil Co. v. FERC, 645 F.2d 360, 392 (5th Cir. 1981), *cert. denied*, 454 U.S. 1142 (1982); *accord* Transcontinental Gas Pipe Line Corp., Order No. 135, 17 FERC ¶ 61,232 at 61,450 (1981) ("The presumption . . . is the same as that which arises from a prima facie case: it imposes on the party against whom it is directed the burden of going forward with substantial evidence to rebut or meet the presumption, but does not shift the burden of persuasion.").

[22] *See* Generic Determination of Rate of Return on Common Equity for Electric Utilities, Order No. 389-A, 29 FERC ¶ 61,223 at 61,458 (1984).

30. As to Calpine's inquiry regarding the burden of proof in a three-year market-based rate review procedure, the April 14 Order states that when an applicant fails a screen, the Commission will institute a section 206 proceeding together with a refund effective date.[23] Failure of a screen establishes a rebuttable presumption of market power, which satisfies the Commission's initial burden of going forward in such proceedings. The burden of going forward will then be upon the applicant once such a proceeding is initiated. If the applicant does not present evidence to rebut the presumption of market power, the Commission need not present further evidence in order to establish that the applicant does in fact have market power. Through this approach, the applicant can continue to charge market-based rates, subject to refund, and a complete record can be established to determine whether the applicant has market power.

2. <u>Relevant Geographic Area</u>

31. In the April 14 Order, the Commission concluded that the default relevant geographic market for the interim generation market power analysis should continue to be based on the applicant's control area market or an entire ISO/RTO for applicants located in ISO/RTOs that have sufficient market structure and a single energy market.

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[23] Three-year market-based rate review filings provide the Commission with updated information upon which the Commission can determine whether the seller should continue to be able to charge market-based rates. Because the three-year reviews are not filings to change the rates, terms and conditions of service, they are not filings under section 205. As the Commission explained in the April 14 Order, "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 proceedings 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." April 14 Order, 107 FERC ¶ 61,018 at P 201.

For purposes of running the indicative screens, the control area includes both the control area market where the applicant is physically located,[24] as well as the control areas directly interconnected to the applicant's control area (first-tier control areas).[25]

a. Rehearing Requests

32. On rehearing, several parties state that the April 14 Order is an improvement over the SMA Order because it now permits applicants to show that a control area may not accurately reflect the borders of the market.[26] EEI states that the Commission has made a positive improvement by recognizing that a control area may not be the relevant geographic market.[27]

33. Several parties argue that the Commission's approach of defining the default relevant geographic market as the control area does not take sufficient account of transmission constraints and load pockets, which may justify the use of larger or smaller geographic market. They assert that relevant geographic markets should instead be based on known transmission constraints and key institutional factors.[28] NRECA argues that the Commission should require applicants that are jurisdictional control area operators to report the necessary information, which is readily available from their Energy Management Systems.[29] Cinergy believes that the approach of defining the default

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[24] For applications by sellers with no generation assets in the ground (such as power marketers) that are affiliated with generation asset owning utilities, the Commission stated in the April 14 Order that it will continue to evaluate the affiliate generation owner's market power when evaluating whether to grant market-based rate authority for the power marketer. April 14 Order, 107 FERC ¶ 61,018 at P 73 n.63.

[25] Where a merchant 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 historical practice. *Id.*, 107 FERC ¶ 61,018 at P 73 n.64.

[26] *See, e.g.,* Request for Rehearing of PacifiCorp at 2.

[27] Request for Rehearing of EEI at 7.

[28] Requests for Rehearing of NRECA at 17, Cinergy Services, Inc. (Cinergy) at 19. EPSA, however, notes that there is no commonly established definition of a load pocket needed for the assessment of geographical generation market power. Request for Rehearing of EPSA at 6.

[29] Request for Rehearing of NRECA at 15-19.

relevant geographic market as the control area is flawed because, first, flowgates, rather than control area boundaries, reflect points of transmission congestion and associated separation of market equilibrium prices.[30] Second, the control area functions identified by the Commission are unrelated to any of the established economic principles associated with defining the extent of a geographic market for purposes of analyzing a supplier's ability to exercise market power.[31]

b. Commission Determination

34. Some sellers argue that the relevant default geographic market should be broader than the control area, while public power entities argue that it should be smaller. Although parties have provided additional comments and recommendations, they have submitted no compelling evidence that our historical approach of evaluating market power on a control area-by-control area basis is inadequate for the typical situation. We emphasize that the use of a standard screen requires us to choose a default geographic market. Utilization of a control area for the default geographic market is beneficial because the data necessary to conduct the screens is generally available on a control area-by-control area basis. Further, the April 14 Order allows applicants and intervenors to present evidence on a case-by-case basis to show that some other geographic market should be considered as the relevant market in a particular case. This approach takes into consideration data that may more accurately reflect the market conditions of a particular applicant, which provides flexibility to applicants and intervenors, as well as certainty to the industry as a whole regarding the default relevant geographic market. The case-by-case approach advocated by certain parties does not appear to provide any alternate default market definition, leaving applicants and intervenors the difficult task of guessing what the geographic market may be in any given case. Therefore, parties have failed to persuade us on rehearing that we erred in the April 14 Order by concluding that the default relevant geographic market for the interim generation market power analysis should be based on the applicant's control area market.

35. As noted in the April 14 Order, moreover, we recognize the possibility that defining the relevant geographic market on a control area-by-control area basis may not be appropriate in all circumstances. Accordingly, we will continue with the determination made in the April 14 Order that the approach of defining the default relevant geographic market as the control area is adequate and allow applicants and

[30] Request for Rehearing of Cinergy at 4.

[31] *Id.* at 6.

intervenors on a case-by-case basis to provide historical data and other evidence to demonstrate that, due to transmission limitations, the relevant market or markets is larger or smaller than the control area.[32]

36. This approach takes into consideration data that may more accurately reflect the market conditions of a particular applicant, which provides flexibility to applicants and intervenors, as well as certainty to the industry as a whole regarding the default relevant geographic market. Thus, we deny rehearing of the definition of the default relevant geographic market.

3. Transmission Limitations

37. The April 14 Order replaced total transfer capability (TTC) with simultaneous transmission import capability as the appropriate measure of transmission capability available for imports. The April 14 Order requires transmission-providing utilities seeking to obtain or retain market-based rate authority to conduct simultaneous transmission import capability studies for their home control area market and each of their interconnected first-tier control area markets using methodologies contained in their Commission-approved OATT.[33] The transfer capability should reflect any operational limits (such as for stability and voltage) that were historically used to execute the provisions of the transmission-providing utilities' tariff during each seasonal peak. In approximating its control area's simultaneous transmission import capability, the transmission-providing utility must utilize a comprehensive/aggregated set of contingencies and monitored line listings used historically, during seasonal studies, to analyze both internal and external transmission constraints. We stated in connection with our discussion of the pivotal supplier analysis that any simultaneous transmission import capability should first be allocated to the applicant's uncommitted remote generation.[34]

38. As we explained in the April 14 Order, an applicant may provide a streamlined application that does not include a simultaneous transmission import capability study, provided that it can show that it passes both screens for each relevant geographic market without considering imports. Further, if an applicant demonstrates that it is unable to

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[32] April 14 Order, 107 FERC ¶ 61,018 at P 66, 75.

[33] *Id.*, 107 FERC ¶ 61,018 at P 81, 84.

[34] *Id.*, 107 FERC ¶ 61,018 at P 95.

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.[35]

39. To the extent we allow the use of a geographic market other than the control area market or ISO/RTO, the proponent of using that alternative market must adhere to *all* monitored lines and critical contingencies that were historically applied during the seasonal peaks in assessing available transmission for non-affiliate transmission customers.[36]

a. <u>Rehearing Requests</u>

40. Some parties support the Commission's decision to use simultaneous transmission import capability rather than TTC to measure potential imports into a control area because it provides a more accurate representation of the ability of suppliers located in first-tier markets to compete in the applicant's home control area market.[37]

41. A number of investor-owned utility parties seek rehearing and clarification arguing that there is a contradiction within the April 14 Order as to its instruction to rely on methodologies consistent with the OATT when performing a simultaneous transmission import capability study and the requirement to allocate simultaneous transmission import capability first to the applicant's uncommitted remote generation capacity located in the first-tier market. EEI argues this instruction will artificially reduce the transmission capability available to non-applicant suppliers and that it assumes a violation of the Commission-approved OATT, with the result that it will improperly bias the results of both screens.[38] AEP adds that any requirement to first allocate simultaneous transmission import capability to the applicant's uncommitted remote

[35] *Id.*, 107 FERC ¶ 61,018 at P 85.

[36] *Id.*, 107 FERC ¶ 61,018 at P 86.

[37] Requests for Rehearing of EEI at 41, NRECA at 4.

[38] Requests for Rehearing of EEI at 43, Southern Companies at 24-25.

generation capacity should only occur if that remote generation is a designated network resource.[39] Southern Companies notes that the April 14 Order suggests that applicants should be deemed to have first call on simultaneous transmission import capability for both their "home" control areas and for that of adjacent control areas as well.[40]

42. Various parties contend that the Commission should modify its methodology for calculating simultaneous transmission import capability. While Duke agrees that simultaneous transmission import capability provides a more accurate reflection of the amount of energy that could be delivered into the applicant's control area than the sum of the posted TTCs at an applicant's interfaces, Duke recommends that the Commission allow applicants, in lieu of the methodology adopted in the April 14 Order, to propose the use of simultaneous TTCs to calculate simultaneous transmission import capabilities.[41] According to Duke, the Commission's methodology for determining simultaneous transmission import capability requires applicants to perform a complex series of data-intensive and time-consuming calculations. Applicants will likely employ different models and assumptions in performing them, which will result in widely varying results for the same interfaces. Duke urges the Commission to permit applicants to use reasonable proxies for simultaneous transmission import capability. According to Duke, such an approach would facilitate analyses prepared by non-transmission owning applicants.

43. EEI and Southern Companies propose that the simultaneous transmission import capability measure should include transmission reliability margins (TRM) and capacity benefit margins (CBM) because both TRM and CBM are generally available for non-firm transmission transactions. The exclusion of such measures from simultaneous transmission import capability would, it is asserted, understate the import capability available for commercial transactions. Finally, according to NRECA, the Commission erred in failing to specify that the calculation of simultaneous transmission import capability should exclude the sum of an applicant's and its affiliates' actual transmission uses, as well as its rights, from the amount of capability deemed available to the market, as the actual uses may exceed their reservations.[42]

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[39] Request for Rehearing of AEP at 8-9.

[40] Request for Rehearing of Southern Companies at 41.

[41] Request for Rehearing of Duke at 12-13.

[42] Request for Rehearing of NRECA at 28-29.

44. APPA/TAPS seeks clarification and/or modification on the following points. First, the Commission should require applicants to assign simultaneous transmission import capability subject to firm point-to-point or network reservations to other holders. Second, the Commission should clarify whether the instructions in Appendix E of the April 14 Order mean that the applicant is supposed to perform a power flow study that considers simultaneous imports from all first-tier markets or whether applicants should make the assumption within the power flow study that the first-tier markets are all in the same location. Finally, the Commission should clarify the instructions in Appendix E regarding certain adjustments to the calculations of the quantity of power that the transmission system is physically capable of transferring.[43]

b. Commission Determination

45. In response to the argument that the April 14 Order improperly directs applicants to first allocate simultaneous transmission import capability to their own uncommitted remote generation, we clarify that only the portion of an applicant's uncommitted remote generation capacity that has firm or network reservations should be modeled in the base case and subtracted from available simultaneous transmission import capability.[44] Specifically, remote resources owned or controlled by the applicant or its affiliates that are located in first-tier control areas should be modeled in each seasonal power flow case at the output level that utilizes the network or firm point-to-point transmission reservations historically used by the applicant or its affiliates. The remaining capacity should be modeled as uncommitted capacity and, with other unaffiliated supply, ramped up pro-rata to calculate the simultaneous transmission import capability into the area under study. This treatment is consistent with the pro forma tariff (OATT) that gives priority to network and firm point-to-point reservations over non-firm reservation requests.

46. We will reject Duke's proposal that we allow applicants to utilize simultaneous TTCs for calculating simultaneous transmission import capability. As discussed in detail in our April 14 Order, commenters explained that TTC is a measure of the maximum transfer capacity of a transmission line, but it does not reflect reliability and operational limits on the line that reduce the amount of generation that could be simultaneously imported into an applicant's control area. We therefore replaced the use of TTC with simultaneous import capability as the more accurate and appropriate measure of the effect of transmission limitations on how much generation can actually be imported into the

[43] Request for Rehearing of APPA/TAPS at 30-32.

[44] April 14 Order, 107 FERC ¶ 61,018 at P 95.

relevant market.[45] The April 14 Order, as clarified in the instant order, gives sufficient guidance to ensure that applicants will reach consistent results, whereas Duke's proposal could lead to vastly differing results because under Duke's approach no standard would be established. With respect to Duke's concerns about non-transmission owning applicants, the April 14 Order requires transmission-providing applicants to conduct simultaneous transmission import capability studies for their control area market and for each of their interconnected first-tier control area markets,[46] while the May 13 Order directs transmission-owning applicants to be the first to file their revised generation market power analysis, along with their simultaneous transmission import capability studies.[47] This approach will facilitate making the required data available to non-transmission owning applicants for use in performing their generation market power analyses. However, we note that in instances where an applicant demonstrates that it is unable to perform a simultaneous transmission import capability study for the control area in which it is located, the April 14 Order permits the applicant to propose to use a proxy amount for transmission limits, which we will consider on a case-by-case basis.[48]

47. We reject EEI and Southern Companies' proposal that the simultaneous transmission import capability measure should include TRM. In other words, EEI and Southern Companies propose to ignore TRM in the base case, thus making a larger amount of simultaneous transmission import capability available to competing generators. TRM is controlled by the transmission-providing utility and should not be ignored. Therefore, base cases should include TRM on appropriate flowgates. TRM is a margin prescribed by the North American Electric Reliability Council (NERC) to insure that grid reliability remains a priority.

48. In response to claims by EEI and Southern Companies, we clarify that the simultaneous transmission import capability measure should account for CBM to the extent that it was historically available to non-firm transmission markets during recent seasonal peaks. However, to the extent that CBM transmission margins were utilized for system reliability during recent seasonal peaks, base cases should reflect the amounts actually reserved and thus will not be treated as part of simultaneous transmission import capability. Because the Commission requires that a transmission-providing utility make

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[45] *Id.*, 107 FERC ¶ 61,018 at P 82.

[46] *Id.*

[47] May 13 Order, 107 FERC ¶ 61,168 at P 9.

[48] April 14 Order, 107 FERC ¶ 61,108 at P 85.

CBM available to all transmission customers, CBM should be modeled in the base case to reflect the amount actually reserved for reliability during recent seasonal peaks.[49] Thus, in constructing the base case, it is appropriate to de-rate paths that utilized CBM for unit outages or model the resource that experienced a forced outage, which caused this amount of CBM to be unavailable to non-firm wholesale transmission markets.

49. The April 14 Order stated that non-affiliate, non-network firm contracts should not be modeled when simulating non-affiliate transmission access to the transmission provider's home control area.[50] This simplification to the modeling process was based on the assumption that all reservations historically controlled by non-affiliates would have been used to compete to inject energy into the transmission provider's control area market if market power or scarcity was driving market prices above other regional prices. Therefore, the Commission rejects APPA/TAPS's request to model unaffiliated supply transmission reservations as not available for competing supply.

50. However, we clarify, consistent with APPA/TAPS' request, that all first-tier interconnecting control areas are to be modeled as a single surrounding entity for the purposes of calculating simultaneous transmission import capability, voltage limits, and stability limits.

51. With regard to requests for guidance in modeling or making adjustments to the base case for TRM, and portions of CBM not available to firm and non-firm transactions, we clarify that:

a. If TRM is reserved by the transmission-providing utility applicant on any flowgate or path, the lines associated with such flowgate or path should be de-rated to reflect the reliability margin that is not available to transmission customers for non-firm transmission reservations during recent seasonal peaks;

b. If CBM is not made available, in whole or in part, to non-firm markets, the base case should reflect the reliability margin by modeling generation outage and path de-ratings that simulate the CBM not available to unaffiliated transmission customers in non-firm transmission markets (modeled as inputs in the base case);

[49] *See* Capacity Benefit Margin in Computing Available Transmission Capacity, 88 FERC ¶ 61,099 at 61,237-38 (1999).

[50] April 14 Order, 107 FERC ¶ 61,018 at Appendix E.

c. If counterflow margins are maintained seasonally and not made available for non-firm reservations requested by transmission customers, the applicable lines should be de-rated appropriately on lines/flowgates such that counterflow margins were maintained during each recent seasonal peak;

d. If any other reliability margin was utilized by the applicant during recent seasonal peaks, those margins should appear as de-rated lines, as appropriate, in developing the base case.

4. Reductions in Generation Attributed To Applicants

52. Both the pivotal supplier analysis and the market share analysis recognize utilities' obligations to serve native load. However, because utilities generally use the same generating units to make off-system wholesale sales and to serve native load, and since the amount of generation needed to serve native load can vary from hour to hour, the April 14 Order adopted a reasonable proxy to represent the amount of generation needed to serve native load. The pivotal supplier analysis uses 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 uses the native load obligation on the minimum peak demand day for a given season.[51]

a. Rehearing Requests

53. On rehearing, a number of investor-owned utilities support the Commission's decision to allow applicants to deduct native load, certain long-term firm sales, operating reserves[52] and planned outages for the purpose of calculating the amount of uncommitted capacity available for sale in the wholesale markets.[53] Dominion supports the Commission's determination that native load obligations and operating reserve

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[51] April 14 Order, 107 FERC ¶ 61,018 at P 35.

[52] Request for Rehearing of AEP at 4.

[53] Requests for Rehearing ofDominion at 2, Duke at 4, EEI at 14-15, PacifiCorp at 1.

requirements are to be factored into the new market power screens.[54] PacifiCorp also supports the Commission's consideration of an applicant's operating reserves and planned outages in performing the market power screens.[55]

54. Other parties reject the Commission's decision to deduct native load, arguing that there are inherent problems in determining the proper amount to deduct, that such a deduction is inconsistent with the Merger Policy Statement, and that such a deduction may cause "false" positives with respect to merchant generators.[56] NRECA contends that, due to the inherent problems in determining whether capacity is in fact "uncommitted", the Commission should consider all generation in an applicant's portfolio for purposes of generation market power analysis, while allowing an applicant that fails the relevant screens to present evidence of such native load commitments as a mitigating circumstance.[57]

55. Several investor-owned utilities assert that the Commission's methodology for calculating the amount of uncommitted capacity contains a number of flaws, which, they argue, overstate the applicant's uncommitted capacity and the size of the wholesale market. EEI argues that, because the pivotal supplier analysis uses an average to determine the native load proxy, some part of the applicant's native load is not accounted for and becomes included as part of the wholesale market, which, it alleges, overstates the applicant's uncommitted capacity.[58] FirstEnergy contends that the April 14 Order's native load proxy understates committed capacity because it uses the monthly average, rather than the needle peak for native load. FirstEnergy argues that as demand increases

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[54] Request for Rehearing of Dominion at 2.

[55] Request for Rehearing of PacifiCorp at 1.

[56] Request for Rehearing of NRECA at 29-30, Calpine at 9-11, and EPSA at 11.

[57] Request for Rehearing of NRECA at 29-30. *See also* Requests for Rehearing of Calpine at 9-11, EPSA at 11.

[58] Request for Rehearing of EEI at 21. *See also* Requests for Rehearing of Duke at 5, FirstEnergy at 9.

during peak periods, generation owners with retail native load obligations must preserve their resources to the extent that they may be needed to serve their own power supply needs.[59] In order to address these problems, EEI urges the Commission to allow a case-by-case determination of the appropriate deduction for native load.[60]

56. According to EEI, the market share screen is similarly flawed because the proxy for native load (*i.e.*, the minimum daily peak demand in a given season) is measured at the hour when the applicant will have the greatest amount of seasonal surplus generation capacity.[61] Southern Companies contends that using the lowest peak day of the year as a "proxy" for an applicant's native load obligations overstates the applicant's uncommitted capacity at all other times during the season.[62] AEP suggests instead that the Commission use the average daily peak of the low load month.[63] EEI argues that the Commission has provided no explanation or justification for its choice of the seasonal minimum daily peak demand as a proxy for native load for off-peak periods, or why a seasonal average is used to calculate the deduction for planned outages.[64]

57. Public power parties also argue that it is inappropriate to permit capacity and load deductions for requirements sales and long-term firm non-requirements sales that expire during the market-based rate authorization period because the associated capacity and load will then be available to make wholesale sales.[65] NRECA suggests that long-term firm sales with a term of less than five years should not be deductible,[66] while APPA/TAPS contends that it is only appropriate to deduct capacity associated with firm, long-term commitments where the seller has turned over dispatch rights to a buyer.[67]

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[59] Request for Rehearing of FirstEnergy at 8-9.

[60] Request for Rehearing of EEI at 21.

[61] Request for Rehearing of EEI at 32-33.

[62] Request for Rehearing of Southern Companies at 11-13.

[63] Request for Rehearing of AEP at 7.

[64] Request for Rehearing of EEI at 32-33.

[65] Requests for Rehearing of APPA/TAPS at 24-26, NRECA at 33-38.

[66] Request for Rehearing of NRECA at 36.

[67] Request for Rehearing of APPA/TAPS at 25.

58. A number of parties seek clarification that "load following" or "provider of last resort" contracts will be treated as committed capacity.[68] According to EEI and PSEG, this is appropriate because the obligations that suppliers have under these wholesale contracts are akin to the obligations that an integrated utility would have to serve its native load.[69]

59. Parties suggest a number of other modifications to the Commission's methodology for calculating uncommitted capacity. AEP suggests that a further deduction be provided to allow for forced outages, in addition to that for planned outages.[70] APPA/TAPS argues that the Commission should allow intervenors to challenge applicants' calculation of uncommitted capacity and the specific deductions taken, and that market-based rate authority should be limited to the amount of uncommitted capacity used to calculate the screens.[71] Finally, NRECA argues that the Commission erred in failing to account for the availability of reserve capacity to produce non-firm energy and for the potential for withholding of such energy to increase prices.[i]

b. Commission Determination

60. In the April 14 Order, the Commission concluded that the approach it has adopted balances regulatory certainty with appropriate flexibility for applicants and intervenors to present case-specific evidence that is relevant to the evaluation of market-based rate applications.

61. As an initial matter, we agree with NRECA that there are inherent difficulties in distinguishing between committed and uncommitted capacity. However, we will not adopt NRECA's proposal to continue the SMA's approach of considering all generation capacity, while allowing applicants that fail such a screen to present evidence of native

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[68] Requests for Rehearing of PSEG Energy Resources & Trade LLC and PSEG Power LLC (PSEG) at 10, EEI at 21. These commenters are primarily concerned with the treatment of capacity that is dedicated to serving retail customers under contracts awarded via supply auctions. Such contracts are common in states such as Maryland and New Jersey that have introduced retail choice.

[69] Request for Rehearing of PSEG at 10

[70] Request for Rehearing of AEP at 9.

[71] Request for Rehearing of APPA/TAPS at 21-24.

load commitments as a mitigating circumstance. Such an approach does not adequately address the issue of committed capacity that is already dedicated and not otherwise available to compete in wholesale markets.

62. Regarding the use of proxies to account for native load obligations, a problem inherent to screens is that they sacrifice some degree of precision for administrative convenience. For example, by examining uncommitted capacity only during the system peak month, the pivotal supplier screen may miss an applicant's ability to exercise market power during other system conditions and thereby may understate a utility's potential to exercise market power. The market share analysis' tendency is in the other direction, by looking at the maximum amount of capacity the applicant might be able to sell into the market. Additional conditions and measures could always be taken into account for greater precision, but taking that approach would move away from our balanced approach that employs a relatively simple analysis as initial screens for market power. On this basis, we are not persuaded to change our approach on rehearing.

63. Regarding the pivotal supplier analysis in particular, we reiterate that conditions in peak periods can provide significant opportunities to exercise market power. As capacity is utilized to meet rising demand, there is less available to sell on the margin and often less competition. FirstEnergy's argument regarding a utility preserving its resources discussed above only serves to illustrate this point. As demand increases during peak periods and generation owners preserve their resources to the extent that they may be needed to serve their own power supply needs, fewer units are available to serve anticipated peak needs, with the result that the potential for the exercise of market power increases.

64. We also reject EEI's proposal that we allow a case-by-case determination of the appropriate deduction for native load obligations. Because the portion of capacity solely dedicated to serving native load changes with market conditions, the April 14 Order adopted a conservative approach in determining a proxy for native load obligations under the market share analysis and a less conservative approach under the pivotal supplier analysis. Our approach in this regard, which allows applicants that fail a screen to rebut the presumption of market power by presenting a Delivered Price Test and historical data, balances the need to account for capacity committed to serving native load against the need to develop accurate screens to identify applicants with the potential to exercise market power.[72]

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[72] April 14 Order, 107 FERC ¶ 61,018 at P 90.

65. With regard to concerns that the April 14 Order failed to provide for reductions to installed capacity for long-term firm full-requirements sales, we clarify here that, where appropriate, applicants may deduct for long-term firm requirements sales that are specifically tied to generation owned or controlled by the applicant, as requested by APPA/TAPS.[73] An applicant may only add or subtract long-term firm purchases or sales, respectively, that assign operational control of such capacity to the buyer. In short, if an applicant has control over certain capacity such that the applicant can affect the ability of that capacity to reach the relevant market, then that capacity should be attributed to the applicant when performing the screens.

66. We clarify that applicants may deduct "load following" and "provider of last resort" contracts for terms of one year or more under certain conditions. We recognize that the load following nature of such contracts is not directly captured by capacity measures due to the daily and seasonal variation in use of the generation following the customers' demand. Furthermore, such contracts are not necessarily tied to a specific generating unit and do not convey operational control of generation. It appears that these contracts are more similar to energy products for which market conditions vary hourly, daily and seasonally. Therefore, we will allow applicants to deduct long-term firm load following contracts to the extent that the applicant has included in its total capacity a corresponding generating unit or long-term firm purchase contract (as specified above) that will be used to meet the obligation. The applicant's contractual peak load obligation under the contract should be used as the capacity adjustment in the pivotal supplier analysis and the seasonal baseline demand levels served under the contract should be used as the adjustments in the market share analysis. The residual capacity will be considered available for sales in the wholesale spot markets and treated as uncommitted capacity.

67. We reject NRECA's suggestion that the Commission should treat capacity that is tied up in a long-term contract of less than three years as uncommitted. It would be administratively infeasible and potentially disruptive to require such a minute evaluation of all long-term contracts. Rather, we will continue to require applicants to base their analysis on a "snap-shot" in time as representative of their potential to exercise market power. We counterbalance this approach by allowing intervenors to present historical wholesale sales data and actual historical transmission usage and will continue to require a three-year market-based rate review.

[73] When we referred to "long-term firm non-requirements sales" in the April 14 Order, we intended "long-term firm sales" and the modifier "non-requirements" was inadvertently included. *See* April 14 Order, 107 FERC ¶ 61,018 at P 93.

68. Further, we will not adopt AEP's suggestion to allow deductions for forced outages. Forced outages are non-recurring events that do not reflect normal operating conditions, and AEP has not adequately supported its suggestion.

69. In addition, as suggested by APPA/TAPS, we clarify that parties may challenge representations as to the uncommitted capacity used in the generation market power analysis. While we would not expect disputes of material facts, we will not preclude intervenors from voicing concerns about the accuracy of such inputs and calculations. For example, an intervenor may disagree with an applicant's measurement of the lowest native load level for the season or the number of megawatt-days of planned outages and present the relevant supporting data.

70. We reject APPA/TAPS' suggestion that we limit any market-based rate authority to the amount of uncommitted capacity used in the screen calculations. The screens are indicative of an applicant's ability to exercise market power using its entire fleet of resources. As such, there is no need to limit the scope of market-based pricing authority based on limitations in a screen analysis. If a party believes that an applicant that passes an indicative screen analysis actually has market power, additional evidence and analysis may be presented that demonstrates the applicant's market power. Moreover, the amount of uncommitted capacity used in the screen is a reasonable measure that allows us to identify those firms that do not have market power. We recognize that sellers' true uncommitted capacity will vary across time, and we would not want to restrict sellers that do not have market power from competing whenever possible by limiting market-based sales based on our measure of uncommitted capacity.

71. Finally, with respect to NRECA's criticism that we failed to account for the availability of reserve capacity to produce non-firm energy and for the potential for withholding of such energy to increase prices, we have designed an approach to reflect the specific operating reserve requirements of the relevant market. By specifying that an applicant should employ the operating reserve requirements established by the state or regional reliability council, we are specifying a measure that is known, measurable and publicly available. NRECA's suggested approach, in contrast, would require calculation and analysis of data that may change minute-to-minute, day-to-day or seasonally and cannot be implemented on a generic basis. However, if an intervenor provides conclusive evidence that, in practice, an applicant has not complied with the NERC or regional reliability council operating reserve requirements, we will take this into account in determining the amount of operating reserve deduction.[74]

[74] *Id.*, 107 FERC ¶ 61,018 at P 96.

5. <u>Pivotal Supplier Analysis Using Uncommitted Capacity</u>

72. As outlined in the April 14 Order, the first step in the pivotal supplier analysis is to determine the total amount of uncommitted capacity available for wholesale sales in the relevant geographic market by the applicant and its competitors. The uncommitted capacity for each is determined by, first, adding the total nameplate capacity of generation owned or controlled through contract and firm purchases that is located in the relevant geographic market and first-tier control area markets (limited by simultaneous transmission import capability), then subtracting operating reserves, native load commitments and long-term firm sales, as discussed above.

a. <u>Rehearing Requests</u>

73. Investor-owned utility parties generally support the April 14 Order's modifications to this screen. In particular, they approve of the Commission's decision to adjust for native load and other obligations, which properly recognizes that this capacity is not available for resale.[75] They similarly support the use of the pivotal supplier analysis as a screen and the use of uncommitted capacity as the measure of each supplier's capacity.[76]

74. Some parties contend that the pivotal supplier analysis should be applied in each month, rather than being limited to the month in which the needle peak occurs, because a supplier may be pivotal at other times besides the single, annual peak month.[77]

75. FirstEnergy asserts that the pivotal supplier analysis erroneously relies on inconsistent measures to determine both uncommitted capacity and the size of the relevant wholesale load: native load reflects average monthly peak loads during the peak month, the uncommitted capacity calculation is based on total generation capacity available to serve the needle peak, and the wholesale load calculation is based on the total control area needle peak.[78] FirstEnergy urges the Commission to adopt consistent measures, but does not offer any suggestions as to what these should be.

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[75] *See, e.g.,* Request for Rehearing of EEI at 20.

[76] *See, e.g.,* Request for Rehearing of AEP at 6.

[77] Requests for Rehearing of NRECA at 31-32, APPA/TAPS at 26-27.[78] Request for Rehearing of FirstEnergy at 10.

76. The New Mexico Attorney General, *et al.* asserts that the key terms in the equation defining peak load for the purposes of this test are unclear and need to be clarified. According to the New Mexico Attorney General, *et al.*, the Commission's definitions of peak load and needle peak omit the non-firm wholesale sales actually made that were needed to meet the total peak load at that time.[79] The New Mexico Attorney General, *et al.* also suggests that it would be much clearer if the Commission were to define each screen in terms of a simple mathematical equation, rather than in words, and to provide a list of all the final definitions of the terms input into these equations.[80]

b. Commission Determination

77. In designing the generation market power analysis, the Commission has taken into account the comments and concerns of all industry participants. We reject the suggestion that we broaden the pivotal supplier analysis to include monthly assessments. In adopting two indicative screens (*i.e.*, pivotal supplier and market share) we have struck a balance between two different market power analyses. The pivotal supplier analysis examines the applicant's market power during the peak hour of the year. The hours leading up to that point in time are the most likely time that an applicant will be a pivotal supplier. The market share analysis, on the other hand, examines all seasons of the year for potential market power. We believe these screens provide a fair assessment of generation market power that will indicate the potential for generation market power in those instances where it may be present and "pass" those utilities where the potential for market power is remote. In addition, both applicants and intervenors may rebut the results of the indicative screens.

78. With respect to the request of New Mexico Attorney General, *et al.* for clarification of paragraph 98 of the April 14 Order, we clarify that peak load is the largest electric power requirement (based on net energy for load) during a specified period of time, usually integrated over one clock hour and expressed in megawatts, for the native load, firm wholesale requirements, and non-firm wholesale sales actually made in the relevant geographic market during the relevant time period.[81]

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[79] Request for Rehearing of New Mexico Attorney General, *et al.* at 18 (citing April 14 Order, 107 FERC ¶ 61,018 at P 98).

[80] *Id.* at 18.

[81] Notwithstanding the above, non-firm wholesale sales may not be included in the calculation of the proxy for native load obligations for purposes of determining the applicant's uncommitted capacity.

6. Wholesale Market Share Analysis Using Uncommitted Capacity

79. The market share analysis measures whether an applicant has the potential to exercise market power based on the applicant's share of the total uncommitted capacity in the relevant geographic market. The calculation of uncommitted capacity for use in the market share analysis differs from that used in connection with the pivotal supplier analysis in that, first, the proxy for native load is the minimum peak load day for each season considered,[82] and, second, applicants may deduct for planned outages.

80. Under the market share analysis, applicants with a market share of less than 20 percent for all seasons pass,[83] while those with a market share of 20 percent or more in one or more seasons fail. As discussed above, both applicants and intervenors may submit a Delivered Price Test and other evidence to contest the results of the screen.[84]

a. Rehearing Requests

81. As discussed above, investor-owned utility parties criticize the market share screen as being too conservative, while other parties argue that it is too lenient. A number of investor-owned utilities argue on rehearing that virtually all traditional vertically-integrated utilities will fail the market share analysis because it fails to take into account off-peak demand and supply conditions.[85] According to these parties, the fundamental flaw of the market share analysis is that it ignores the relationship between loads during off-peak times and the amount of generation that is economically available to serve those loads because it, *inter alia*, calculates market share on the basis of capacity rather than actual sales.

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

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

[84] 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.

[85] Requests for Rehearing of Duke at 2, EEI at 31-34, FirstEnergy at 10-13, Pacificorp at 3.

82. According to EEI and Southern Companies, the market share screen systematically overstates vertically-integrated utilities' potential to exercise market power in two ways. First, EEI argues that the Commission's proxy for native load is too low because, by using the minimum daily peak demand, it will necessarily include as part of the wholesale market a portion of capacity used to serve peak native load on all other days during the season. Southern Companies contends that using the lowest peak day of the year (when the exercise of market power is of least concern) as a proxy for an applicant's native load obligations will seriously understate that applicant's generation supply both for capacity sales at any time and for energy sales at higher peak times (when the exercise of market power is of greatest concern).[86] Second, the market share screen does not adequately account for off-peak periods when many wholesale customers are capable of self-supply or may have surplus capacity.[87]

83. Several parties assert that the market share analysis and, in particular, the 20 percent market share threshold is inconsistent with established principles of antitrust law and economics, the DOJ/FTC 1992 Horizontal Merger Guidelines and the Commission's own merger guidelines. EEI argues that the Commission's citation to the DOJ/FTC 1992 Horizontal Merger Guidelines in support of the 20 percent threshold is inappropriate because this threshold applies in the context of non-horizontal mergers, whereas the market share analysis is a measure of horizontal generation market power. EEI also argues that the economic literature cited by the Commission does not in fact justify the 20 percent market share threshold.[88] Southern Companies argues that the Commission is not justified in applying a merger-type analysis, which examines the structural reduction in competition due to the combination of independent firms, in the context of a market-based rate authority application, which concerns the behavior of a single firm.[89] Southern Companies contends that the standards for monopolization established under section 2 of the Sherman Act are more appropriate to the single-firm context.[90]

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[86] Request for Rehearing of Southern Companies at 13.

[87] Request for Rehearing of EEI at 33.

[88] *Id.* at 26-27.

[89] Request for Rehearing of Southern Companies at 27-29.

[90] *Id.* at 29-39.

84. AEP argues that the April 14 Order's methodology for the calculation of market shares is inconsistent with that applied in the merger context, where the Commission performs its analysis based on uncommitted "economic capacity", *i.e.*, capacity with variable costs low enough that energy from such capacity can be economically delivered to the destination market. AEP urges the Commission to allow participants to perform the market share analysis on the basis of uncommitted capacity that is economical, as defined by the Commission's merger guidelines.[91]

85. Other parties, however, support the market share screen, finding it to be an accurate indicator of market power, but urge the Commission to make the test more stringent, for example, by incorporating a measure indicating applicants' ability to engage in coordinated anticompetitive behavior. APPA/TAPS and NRECA argue that a 20 percent threshold may be too high in certain circumstances, particularly where the market structure is conducive to anticompetitive collusion. Both NRECA and APPA/TAPS assert that a screen such as the Herfindahl-Hirschman Index (HHI), which analyzes both for dominance and market concentration, would be more appropriate for assessing the risk of collusion.[92] New Mexico Attorney General, *et al.* proposes an alternative methodology using behavioral modeling, which could detect coordinated anticompetitive behavior such as collective strategic bidding.[93]

86. Finally, PacifiCorp seeks clarification as to whether applicants should calculate uncommitted capacity on a seasonal basis using data for its capacity, purchases, sales and import availability in effect during the applicable season and whether they should use data reflecting the market's peak demand in each season.[94]

b. **<u>Commission Determination</u>**

87. We note that some of the same parties arguing that the wholesale market share screen is fatally flawed argued that it was, in fact, a viable alternative to the SMA in comments filed in response to the Staff White Paper. For example, EEI member company, XCEL Energy Services Inc. (XES), stated: "Only one of the Commission Staff's proposed alternatives, the Wholesale Market Share screen (WMS), solves the

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[91] Request for Rehearing of AEP at 5 (citing Order 642, which defines economic capacity as capacity whose variable costs are 5 percent or less above the market price).

[92] Requests for Rehearing of NRECA at 14, APPA/TAPS at 29-30.

[93] Request for Rehearing of New Mexico Attorney General, *et al.* at 12.

[94] Request for Rehearing of PacifiCorp at 4.

underlying problem by focusing on a utility's uncommitted capacity. As a consequence, it is the only alternative market screen the Commission Staff proposes that XES believes merits the Commission's further consideration. It would constitute a vast improvement over the SMA."[95]

88. The April 14 Order adopted two indicative screens: a pivotal supplier screen and a market share screen, each with its own specific focus and attributes.[96] The pivotal supplier analysis adopted in the April 14 Order evaluates the applicant in relation to the market demand and supply. The market share analysis, on the other hand, evaluates the applicant's size in relation to others in the market. Taken together, we are able to measure market power both at peak and off-peak times and measure the ability to exercise market power both unilaterally and in coordination with other sellers.[97]

89. The April 14 Order balances the concerns of all market participants when determining the native load proxy for the two screens by using a more conservative proxy for the market share analysis than for the pivotal supplier analysis. The market share analysis looks at the relative size of the applicant versus the rest of the market. It is as reasonable to do this for off-peak times as it is for peak times. We reject the statement that the Commission is relying on the lowest annual peak load as a proxy for the market share analysis because a failure in one season is treated as a failure for the entire year. This statement is predicated on a flawed assumption. An applicant can pass the market share screen in the season with the lowest peak load of the year, while still failing for a different season. In addition, an applicant that fails the market share analysis for only one season may, for instance, propose tailored measures to mitigate its market power during that season. An applicant also has the ability to rebut a presumption of market power. The Commission will also consider any relevant market conditions in determining whether mitigation is necessary and, if so, what form of mitigation would be appropriate.

90. While the pivotal supplier analysis examines the potential for the exercise of market power during the system peak, the Commission also needs a screen that examines sellers during other market conditions because the potential to exercise market power is not necessarily limited to the single system peak. Energy is traded extensively, and some

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[95] January 2004 Comments of XCEL Energy Services Inc. on the Supply Margin Assessment Screen and Alternatives at 17.

[96] April 14 Order, 107 FERC ¶ 61,018 at P 36.

[97] *Id.*, 107 FERC ¶ 61,018 at P 72.

suppliers may be capable of exercising market power throughout the year. The market share analysis addresses the potential for applicants to exercise market power during non-peak conditions by measuring applicants' share of uncommitted capacity available to the wholesale market at those times.

91. EEI, Duke and Southern Companies argue that uncommitted capacity during non-peak periods when demand is relatively low is an unreliable indicator of market power because other suppliers will have substantial surplus capacity during those times.[98] This argument misses the point. The market share screen addresses whether an applicant might be a dominant supplier in the market. Electricity is traded even during non-peak times as utilities seek to displace relatively expensive units and to replace capacity that is out of service. Firms can have a position of dominance that can be exploited during these times, and the market share screen appropriately addresses that potential.

92. Regarding EEI's argument that certain wholesale customers are capable of self-supply during off-peak periods, we note that the market share analysis takes into account the uncommitted capacity of all entities in the market. Thus, the screen does account for wholesale customers who may be capable of self-supply or that have surplus capacity available for sales into the market.

93. Some parties are also concerned that the market share analysis will tend to fail large, traditional suppliers. In addressing concerns raised on rehearing regarding the market share analysis, we must separate the appropriateness of the measure itself from its propensity to fail certain types of applicants. The Commission has a responsibility to ensure that rates are just and reasonable and that sellers are not able to exercise market power. The market share analysis is a screening tool offered for administrative convenience and as such must be designed to pass only those applicants that the Commission can be assured do not have market power with a minimum amount of data and analysis. Those that do not pass the indicative screen warrant a close look. In this regard, we believe that an applicant that has a 20 percent or greater share of uncommitted capacity falls into a range of appreciable size that warrants further examination. As noted above, the screen is not definitive, and applicants may submit historical data and a Delivered Price Test that examine their specific situation and address many of the concerns raised here with respect to the market share screen.

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[98] Requests for Rehearing of EEI at 35-36, Duke at 6-8, and Southern Companies at 39-40.

94. As stated in our April 14 Order, the market share screen is intended to identify those applicants that clearly do not have a dominant position in generation in the market. We noted two models in the economic literature, the Dominant Firm and Competitive Fringe Model and the Stackelberg Leader-Follower Model that show that a dominant firm in a market can raise the price above competitive levels. EEI argues that the link between market share and these models is too weak to justify the screen as a tool because the market share does not measure for, or collect data addressing, the presence of the factors that are the source of dominance.[99] The Commission is not persuaded by these arguments. The purpose of the screen is to pass those applicants that are clearly not likely to be a dominant firm. Since an appreciable amount of capacity provides an indication that an applicant has market power, applicants that have a small share of capacity pass that screen and the remaining applicants warrant further evaluation. We recognize that applicants that "fail" the market share screen may not in fact be a dominant firm, but it is necessary and appropriate to take a closer look at those applicants that the market share screen indicates have potential market power. Applicants failing the initial screen may submit additional evidence to demonstrate whether or not they can act as a dominant supplier, such as historical sales data. Moreover, applicants failing the screen can submit a Delivered Price Test, which does consider relative costs, one of the factors leading to market dominance cited by EEI's witness, Dr. Hall.

95. We also believe that the 20 percent market share threshold is appropriate and we will retain it. We note that the DOJ/FTC Guidelines cite a 20 percent market share as cause for concern that a firm may be able to exercise market power. In addition, we believe that a threshold of no more than 20 percent is appropriate for our use in establishing an indicative screen for generation market power because of the lack of demand elasticity in power markets. In the presence of inelastic demand and without meaningful competing sources of supply, a dominant supplier can increase prices without concern for losing sales. Finally, the Commission has relied on the 20 percent market share threshold in market-based rate applications in the past.[100]

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[99] Request for Rehearing of EEI at 26-27. The reasons cited by EEI for why a dominant firm may gain market power are: lower costs, differentiated product, and through coordinated anticompetitive behavior.

[100] *See, e.g.,* Public Service Company of Indiana, Inc., 51 FERC ¶ 61,367 at 62,205 (1990); Entergy Services, Inc., 58 FERC ¶ 61,234 at 61,758-60 (1992); Louisville Gas & Elec. Co., 62 FERC ¶ 61,016 at 61,146 (1993).

96. EEI argues that the Commission inappropriately cites the DOJ/FTC 1992 Horizontal Merger Guidelines in support of the 20 percent threshold. For horizontal mergers, EEI points out that the DOJ/FTC Horizontal Merger Guidelines state that a market share of at least 35 percent may indicate the ability to profitably increase price through the reduction of output. While EEI is correct that a 20 percent threshold discussed by the DOJ and FTC is in the context of non-horizontal mergers and a 35 percent threshold is discussed in the context of horizontal mergers, EEI misconstrues our point in referring to the 20 percent standard used by the DOJ and FTC. In the context of a non-horizontal merger referred to in section 4.134 of the 1984 Merger Guidelines, the relevant issue is the relative presence of the "acquired firm" in the downstream market. Here, the Guidelines are making the point that a firm with a 20 percent share is unlikely to be a "fringe" firm that is not a significant factor in the market. This is the same reason that we use the 20 percent threshold in our indicative screen: firms larger than that are likely to be significant. We also note that while section 2.22 of the 1992 Horizontal Merger Guidelines discusses the 35 percent threshold referenced by EEI in the context of an ability to unilaterally exercise market power, section 1.51(c) of the Guidelines also concerns mergers that produce very small changes in concentration that occur in markets with HHIs above 1800. Such markets are considered highly concentrated. A market comprised of five firms each with a 20 percent market share would produce a 2000 HHI. Thus, a firm with a market share of 20 percent can be cause for concern and is properly included in our indicative screen. Finally, we note that in markets with low demand price-responsiveness like electricity, market power is more likely at lower market shares.[101]

97. NRECA argues that the market share screen is too high because the analysis does not consider the possibility of coordinated behavior, thus the screen may miss some applicants with a market share less than 20 percent that have the potential to exercise market power. On the other hand, Southern Companies argues that the screen is too low, because the Commission should evaluate market-based rate applicants under the monopolization standards of section 2 of the Sherman Act. The 20 percent threshold strikes a balance between these two conflicting arguments. Specifically, we share NRECA's concern, but we must weigh it against imposing undue regulatory burdens and consider it in context. That is, (1) such applicants may, in fact, fail the other initial screen; and (2) intervenors have the opportunity to present a Delivered Price Test and historical data in order to rebut the presumption that applicants lack market power

[101] In the Cournot model, a standard model of oligopoly theory, the markup of price over cost is calculated as the HHI divided by the absolute value of the price elasticity of demand, *i.e.*, a high markup results from low elasticity. *See*, *e.g.*, Carlton and Perloff, *Modern Industrial Organization* 375 (2nd ed. 1994).

established by passage of both screens. Regarding Southern Companies' argument, section 2 of the Sherman Act addresses market power for different statutory purposes and provides for different remedies. We have a duty to ensure just and reasonable rates, regardless of whether a seller has violated the Sherman Act. In electricity markets, which have relatively little demand response, sellers need not be monopolists to exercise market power and raise prices above competitive levels. For our purposes, such a high threshold would lead to too many false negatives, thus failing to adequately protect wholesale customers. We recognize the need to balance the costs of false negatives and false positives. NRECA and Southern Companies have pointed out examples in which each could occur, and we have considered both in arriving at our 20 percent threshold.

98. We reject AEP's argument that the Commission should perform the market share analysis based on uncommitted "economic capacity". The market share analysis is intended to provide an indication of market power using a straightforward analysis that all applicants will have the resources to provide. The Delivered Price Test provides a more thorough analysis using economic capacity.

99. We deny the requests of parties that the market share analysis be abandoned completely because of the perceived flaws described above. In conjunction with the pivotal supplier analysis, the market share analysis provides useful information for evaluating which market-based rate applications require further scrutiny.

100. Further, as requested by PacifiCorp, we clarify that when calculating uncommitted capacity for each season, data relevant to each season should be used.

7. <u>Delivered Price Test</u>

101. An applicant's failure of either screen establishes a presumption of market power, which an applicant may rebut by presenting a more thorough market power 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,[102] using the framework described in Appendix A of the Merger Policy Statement and revised in Order No. 642.[103] The Delivered Price Test is well established:

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[102] 16 U.S.C. § 824b (2000).

[103] 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. &

(continued)

it has been used routinely by the Commission to analyze market power in the merger context for many years. Since 1996, it has been used in over 100 cases involving mergers, dispositions and acquisitions before the Commission.[104]

a. Rehearing Requests

102. Investor-owned utilities argue that the Delivered Price Test's EC prong – the Delivered Price Test's analog of installed capacity – is too conservative because it does not permit the deduction of native load and other firm sales obligations from a supplier's capacity, as is done with the indicative screens. They argue that traditional utilities are almost certain to fail the Delivered Price Test and thus will not have a reasonable opportunity to avoid the imposition of mitigation measures.[105] These parties urge the Commission to clarify that it will rely only on the AEC prong of the Delivered Price Test – the Delivered Price Test's analog of uncommitted capacity – in order to ensure that native load and other firm sales obligations may be deducted from applicants' capacity and to ensure consistency with the approach taken under the indicative screens.[106]

103. Other parties argue that the Delivered Price Test is too lenient on applicants. APPA/TAPS contends that the 2500 HHI threshold adopted by the Delivered Price Test is an unsupported departure from the Commission's prior reliance on HHIs in the merger context. APPA/TAPS suggests that the Commission should instead adhere to the 1800 HHI threshold for highly concentrated markets as stated in its Merger Policy Statement, which is based on the DOJ's 1992 Horizontal Merger Guidelines. Alternatively, if the Commission retains the 2500 HHI threshold, APPA/TAPS contends

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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).

[104] *See, e.g.*, Commonwealth Edison Co., 91 FERC ¶ 61,036 (2000); American Electric Power Co., 90 FERC ¶ 61,242 (2000); Energy East Corp., 96 FERC ¶ 61,322 (2001).

[105] Request for Rehearing of FirstEnergy at 18.

[106] Requests for Rehearing of AEP at 7-8, Duke at 13-15, EEI at 38-40, Entergy at 22-24, FirstEnergy at 17-18.

the market share threshold should be reduced to 15 percent.[107] The New Mexico Attorney General, *et al.* argues that the Commission has failed to demonstrate that the HHI has any relevance to the assessment of market power in the electricity markets.[108]

b. <u>Commission Determination</u>

104. We deny the requests to clarify that we will rely only on the AEC prong of the Delivered Price Test. The Commission will weigh the results of both the EC and AEC analyses. Applicants and intervenors will have the opportunity to argue which measure more accurately represents the relevant market conditions. Moreover, as indicated by the variety of comments we received regarding the appropriate way to account for native load in the analysis, there is considerable disagreement over how to account for native load obligations. Therefore, we are reluctant to rely solely on AEC in our definitive test for market power.

105. We deny APPA/TAPS' request that the HHI threshold be lowered to 1800 from 2500. We have adopted a conservative test in that applicants must pass all three prongs: pivotal supplier, market share and market concentration for all season/load conditions. Moreover, we stated that passing all three prongs would constitute a showing of a lack of market power, absent contrary evidence from intervenors.[109] Finally, while APPA/TAPS is correct that the 2500 HHI threshold cited in the April 14 Order was proposed in the context of market-based rates for oil pipelines, the procedural circumstances are very similar: in both cases, applicants make a showing that overall market conditions are

[107] Request for Rehearing of APPA/TAPS at 32-34.

[108] Request for Rehearing of New Mexico Attorney General, *et al.* at 15-17.[109] For example, in a case where the market is highly concentrated, but the HHI is less than 2500, and the applicant has a market share close to 20 percent, intervenors could show that the applicant would have market power – especially in cases where there are other large sellers in the market. However, we note that the presence of other large sellers in the market would often result in an HHI greater than 2500, which would fail the HHI threshold.

conducive to competitive outcomes. The other two tests (pivotal supplier and market share) directly assess the role of the applicant in the market. Moreover, while the HHI thresholds contained in the DOJ/FTC 1992 Horizontal Merger Guidelines provide useful measures for analyzing market conditions, these thresholds are based on the antitrust agencies' obligations to prohibit mergers that substantially lessen competition under section 7 of the Clayton Act. Our standards are based on the Commission's statutory obligation under section 205 of the FPA to ensure that wholesale rates are just and reasonable. Therefore, we find that the 2500 HHI threshold, taken in context with the other tests, provides a reasonable balance between the need to identify applicants possessing market power and the goal of avoiding undue regulatory burdens imposed by false positives.

106. We reject the arguments made by the New Mexico Attorney General, *et al.* that concentration measures such as the HHI have no relevance to the assessment of market power in the electricity markets.[110] As we noted in the April 14 Order, concentration statistics, such as the HHI, can indicate the likelihood of coordinated interaction in a market. Moreover, the HHI is used by the antitrust agencies and the Commission in the context of both horizontal and vertical mergers and acquisitions to measure competitive conditions in markets before and after a merger or acquisition in electricity markets. While electricity markets have a unique set of characteristics (such as lack of storability and very low demand elasticity), HHIs have been used in the analysis of electricity market in a number of contexts. The DOJ/FTC 1992 Horizontal Merger Guidelines describes the usefulness of the HHI:

> "Unlike the four-firm concentration ratio, the HHI reflects both the distribution of the market shares of the top four firms and the composition of the market outside the four firms. It also gives proportionately greater weight to market shares of the larger firms, in accord with their relative importance in competitive interactions."[111]

8. <u>Streamlined Applications</u>

107. The rehearing requests of the SMA Order urged the Commission to allow small utilities that are unlikely to possess generation market power to submit streamlined applications expressing concern that, in the case of small, independent power producers,

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[110] The HHI measures market concentration by adding the squared market shares of all suppliers.

[111] DOJ/FTC 1992 Horizontal Merger Guidelines, Revised April 8, 1997, § 1.5.

a comprehensive generation market power analysis may not be necessary and would be unduly burdensome.[112] Accordingly, in the April 14 Order we clarified that such power producers may avoid submitting a generation market power 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 and codified in Order No. 888. While there is 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 that do not affect the underlying methodology utilized by these screens.

a. Rehearing Requests

108. NRECA faults the April 14 Order for not providing a safe harbor or streamlined procedure for small applicants. NRECA argues that this will impose a substantial burden on small electric cooperatives to comply with the April 14 Order because, unlike larger public utilities, smaller systems are unlikely to have access to the data and resources needed to conduct the analyses that the Commission requires.[113]

109. With respect to the scope of the section 35.27 exemption, EPSA requests that the Commission confirm that applicants need not perform the generation market power analysis if construction on all the generation in the relevant market commenced after July 9, 1996. EPSA also requests clarification as to the meaning of the term "area", specifically, if an applicant has a single plant in a control area that qualifies for the section 35.27 exception, would existing facilities owned by the applicant or its affiliate in the adjacent control area require the applicant to perform the generation market power screens; whether transmission ownership is relevant in this analysis; and whether it matters if capacity in the adjacent control areas is committed or uncommitted.[114]

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[112] January 2004 Comments of NRECA at 11; February 2004 Comments of NRECA at 2.

[113] Request for Rehearing of NRECA at 37-39.

[114] Request for Rehearing of EPSA at 19-20.

b. Commission Determination

110. NRECA reiterates on rehearing its earlier comments regarding an exemption for small utilities, which we have already addressed in the April 14 Order.[115] On this basis, we deny NRECA's rehearing request. However, we clarify that in circumstances where construction on all of an applicant's generation commenced after July 9, 1996, no interim generation market power analysis need be performed.

111. With respect to EPSA's request for clarification as to the meaning of "area", we clarify that this term is meant to refer to the relevant market (control area) as described in the April 14 Order. Further, with respect to EPSA's example of a new generator locating in a control area adjacent to a control area where an affiliate owns generation, footnote 64 of the April 14 Order states that "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)."[116] Accordingly, in EPSA's example, the new generator has only one relevant market and no generation market power analysis would be required. On the other hand, if the existing generator was part of the portfolio of an interconnected transmission-owning utility, then the new generator would be part of the interconnected transmission-owning utility's relevant market, and the utility would be required to perform the generation market power analysis.

9. Use of Historical Data

112. In the April 14 Order, the Commission specified that, in performing all screens, applicants are required to prepare them as designed 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. However, as discussed below, we will permit applicants to use the most recently available historical data and to make certain adjustments to the data, provided that the adjustments are sufficiently justified and supported. Accordingly, we will allow the introduction of historical evidence beyond the most recently available 12 months. Finally, applicants filing abbreviated studies may request waiver of the full data requirements.

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[115] Request for Rehearing of NRECA at 37-39.

[116] April 14 Order, 107 FERC ¶ 61,018 at P 73 n.64.

a. Rehearing Requests

113. EEI and Southern Companies seek clarification of the April 14 Order's instruction that directs applicants to use "the most recent unadjusted 12 months' historical data" in performing the screens, which may not have been compiled, much less published, at the time of application. EEI requests that the Commission clarify that an applicant may present the most recently available data rather than just the most recent 12 months' historical data.[117]

114. Southern Companies asserts that the April 14 Order appears to impose an absolute prohibition on the adjustment of data for any reason. It suggests that the Commission should permit applicants to make reasonable, well-supported adjustments to the data. In the alternative, Southern Companies suggests that the Commission could clarify that applicants may produce other evidence that is more factually accurate than the data available to the public.[118]

115. Southern Companies argues that the Commission should clarify that information that is not publicly available cannot be a required element of a filing, or alternatively that entities may make reasonable assumptions based on publicly-available information.[119] For example, the only public source for data on competitors' planned outages is FERC Form 714, which is not in the format required to run the screens.[120]

[117] Request for Rehearing of EEI at 22.

[118] Request for Rehearing of Southern Companies at 22-23.

[119] Southern Companies cites a number of examples of non-public data it would be required to submit as part of its application: independent power producers are not required to submit generation data to be included in EIA-411; non-jurisdictional entities generally do not submit information for inclusion in FERC Form 714; the data reported in EIA-411 is by NERC region/subregion, which Southern Companies contrasts with data by control area which is the metric required in the April 14 Order; publicly-available commercial sources also do not include all of the data needed, for example information on operating reserves or firm contractual obligations. Request for Rehearing of Southern Companies, Little Affidavit at 5, 8.

[120] Request for Rehearing of EPSA at 19. Similarly, FERC Form 714 accounts only for scheduled sales and purchases – not total firm sales and purchases – which may include capacity under firm contract that is not dispatched. Request for Rehearing of Southern Companies, Little Affidavit at 6.

116. Several parties submit that intervenors lack sufficient access to information and the time necessary to perform the generation market power analysis. They suggest that access to the following types of data would be helpful in performing the generation market power analysis: the most timely available native load and control area daily peak demands, simultaneous transmission import capability data, CBM, TRM, committed capacity, uncommitted capacity, planned outages, and reserve levels; the data needed to perform the Delivered Price Test; and information regarding where the applicant's units fall on the supply curve for relevant geographic market or markets.[121] As a remedy, NRECA proposes that the Commission require control area operators that have or are seeking market-based rate authority to post the data necessary to perform the screens on their Open Access Same-Time Information System (OASIS) sites and to regularly update the data.[122] EPSA requests that transmission owners be required to post both simultaneous transmission import capability and operating reserves on their OASIS and to keep them current; alternatively, if the Commission is unwilling to require applicants to post such information, EPSA suggests that applicants should be able to use the TTC as a proxy for the amount of uncommitted capacity in first-tier control area markets.[123] Finally, in order to streamline the process and promote consistent analyses, EPSA urges the Commission to require ISO/RTOs to post the critical inputs for the generation market power analysis.[124]

117. EPSA submits that many elements of the newly-announced screens are susceptible to multiple interpretations and permit a variety of approaches. To allow the industry and the Commission to become more familiar with the new screens and to see what, if any, adjustments are necessary, EPSA suggests the Commission consider a "test run" of the new generation market screens to a small subset of companies, perhaps those identified in the initial orders, before applying this new approach generically.

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[121] Requests for Rehearing of EPSA at 17-19, Joint Consumer Advocates at 6, NRECA at 12.

[122] Request for Rehearing of NRECA at 11-12.

[123] Request for Rehearing of EPSA at 17-18.

[124] *Id.* at 10. These inputs include nameplate generating capacity within the footprint, needle peak, daily average peak demand during the month the peak load day occurs, minimal peak load day for each season, simultaneous transmission import capability, operating reserve and planned outages.

b. <u>Commission Determination</u>

118. Regarding requests for clarification as to the vintage of data to be used in calculating the indicative screens, we clarify here that when we state that applicants are to use the most recent unadjusted twelve months' historical data, we intend this to mean available data. Applicants are to use the most recently available data. We also note that the twelve months need not necessarily track the calendar year. All data used in the screens should be consistent, using data from the same time period for all inputs. However, to the extent necessary, we will allow applicants to use data from different time periods if the need for doing so is sufficiently supported and documented.

119. Further, as requested by Southern Companies, we will allow adjustments that are necessary to perform the screens, provided that the applicant fully justifies the need for and methodology used for the adjustments and files all workpapers supporting the adjustments and documenting the source data used. For example, an adjustment could be allowed where needed data is available only for a region that is not identical to the applicant's control area in order to put it in a form that can be used in the analysis as designed.

120. The April 14 Order allows for the deduction of planned outages consistent with those as reported in FERC Form 714.[125] To the extent the planned outage data in Form 714 is not in the format necessary to perform the screen, we reiterate that applicants can make streamlined applications containing simplifying assumptions based on available data. For example, an applicant could subtract its planned outages, if any, from the total amount identified in the FERC Form 714 and attribute the remaining planned outages to other local generation. In addition, to the extent necessary, applicants may use sources other than FERC Form 714, provided that the applicant sufficiently justifies and supports this adjustment.

121. With respect to data that is only available from commercial sources, we clarify that commercial sources may be used to the extent the data is made available to intervenors and other interested parties. Applicants utilizing commercial information to perform the screens should include it in their filing.

122. With respect to Southern Companies' concern that some of the data necessary to perform the screens is not publicly available, we observe that the information cited by Southern Companies is generally known to the control area operator for transactions within its system. In addition, we find that applicants' ability to submit streamlined applications, to use commercial information and to make certain data adjustments should

[125] April 14 Order, 107 FERC ¶ 61,018 at P 100.

alleviate any impediments based on data availability to performance of the screens as specified in the April 14 Order. Further, parties are reminded that the Electric Quarterly Reports database, which is available to the public on the Commission's website, provides information on all types of wholesale transactions by jurisdictional entities.

123. Similarly, for non-control area operator applicants, we believe that the flexibility the Commission provides will ensure that there are no significant impediments to performing the screens. However, we agree that in certain instances control area operators may have superior access to information. In the April 14 Order, we required that a transmission-providing utility provide simultaneous transmission import capability studies for its home control area and each of its interconnected first-tier control areas when filing its generation market power analysis.[126]

124. Furthermore, in response to concerns about access to data, we would expect control area operators with market-based rate authority to provide simultaneous transmission import capability studies, consistent with the methodology described herein, for their control area and interconnected first-tier control areas in response to requests by applicants seeking market-based rate authority. We do not believe this to be a burdensome request, as we understand that these studies are routinely performed. We have received three-year market-based rate review filings using simultaneous transmission import capability before this requirement was adopted by the April 14 Order.[127] As discussed above, we reject the suggestion that we revert to TTC as a default measure because the simultaneous transmission import capability study is a more comprehensive and accurate measure of the effect of transmission limitations on imports than TTC, even though TTC may be easier to calculate. As stated in the April 14 Order, if an applicant demonstrates that it is unable to perform a simultaneous transmission import capability study for the control area in which it is located, a proxy amount for transmission limits based on reasonable assumptions will be considered on a case-by-case basis. Further, if an applicant can show that it passes our screens for each relevant geographic market without considering imports, a simultaneous transmission import capability study need not be filed.

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[126] *Id.*, 107 FERC ¶ 61,018 at P 82.

[127] *See*, *e.g.*, Triennial Market Power Study Update of Entergy-Koch Trading LP, Docket No. ER01-2781-004, dated January 26, 2004.

125. With respect to comments on intervenors' access to data and the request that workpapers be included in applicants' submittals, we reiterate that applicants are required to submit the minimum data listed in Appendix G of the April 14 Order, as well as appropriate support and workpapers. All of the relevant information will be made available to intervenors and the public when the filing has been posted on the Commission's eLibrary. We will not here require that control area operators post information such as planned outages and operating reserves on their OASIS sites. In the immediate future, we encourage applicants to submit streamlined applications where applicable. To the extent a request for information is received by a public utility, we expect that this request will be satisfied.

126. Regarding operating reserves, applicants are to use, as stated in the April 14 Order, the State or Regional Reliability Council operating reserve requirements as the default measure when calculating the requirement for the analyses.[128] ISO/RTOs may, on a voluntary basis, post information relevant for the analysis to assist their members in performing the screens. We will not conduct test runs of the screens, as the new generation market power screens have already gone into effect as of April 14, 2004. Many entities have already filed the screens, and test runs would impose a burdensome and unnecessary duplication of effort on the part of these applicants.

C. Accommodations for Hydroelectric and Western Interconnect Issues

127. In the April 14 Order, the Commission acknowledged that, because hydroelectric facilities are energy-limited units, using nameplate capacity can bias the results of the generation market power screens and permitted them to de-rate their capacity based on historical capacity factors. The Commission further recognized that the control area market approach may not be the appropriate methodology for defining the relevant geographic market for Western markets and allowed applicants in such markets to present evidence that the relevant geographic market may be wider.

1. Rehearing Requests

128. PacifiCorp believes that the April 14 Order is an improvement over the SMA Order insofar as the Commission has acknowledged the special character of the energy markets in the West and now permits applicants to more accurately reflect the output of their hydropower resources.[129] However, PacifiCorp notes that wind energy units are also energy-limited because they have no storage capability and because their operators

[128] April 14 Order, 107 FERC ¶ 61,018 at P 96.

[129] Request for Rehearing of PacifiCorp at 1.

have no ability to dispatch the units on command, so that nameplate capacity of wind energy units is even less accurate and relevant to the generation market power screens than is nameplate capacity of hydro units. PacifiCorp urges the Commission to clarify that wind energy units may also de-rate their capacity in a manner similar to the de-rating of hydro units. Pacificorp also states that the Commission should allow applicants to submit estimated capacity factors for new units that do not yet have a history of actual output.[130]

2. <u>Commission Determination</u>

129. We agree with PacifiCorp that wind energy units, like hydroelectric units, are energy-limited and clarify that applicants may de-rate the available capacity of wind energy units using a five-year average of historical output. We will also allow applicants to submit estimated capacity factors for new units that do not yet have a history of actual output. We do not want to impede development of wind energy by overstating the market shares of wind energy producers and imposing regulatory burdens.

D. <u>Mitigation</u>

130. The FPA requires that all rates charged by public utilities for the transmission or sale for resale of electric energy be "just and reasonable."[131] 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.[132] 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.[133] Thus, where a market-based rate applicant is found to have market power, 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.

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[130] *Id.* at 3.

[131] 16 U.S.C. § 824d(a) (2000).

[132] *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).

[133] *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).

1. **Price Mitigation**

131. Under the April 14 Order, applicants that have a presumption of market power because they have either failed or foregone the market power screens may either accept the Commission's default cost-based mitigation measures or propose their own case-specific measures tailored to their particular circumstances that eliminate their ability to exercise market power. Such applicants will also have their rates prospectively made subject to refund. 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 or a Commission order addressing whether default or case-specific cost-based rates are to be applied.[134]

a. **Rehearing Requests**

132. Several parties seek rehearing and clarification regarding the scope of the mitigation measures outlined in the April 14 Order. Some parties urge the Commission to impose a broader range of mitigation measures, in particular, structural remedies. APPA/TAPS proposes that the Commission impose a range of structural remedies that will ensure access to alternative suppliers, relieve transmission constraints, reduce concentration and increase the liquidity of markets.[135] EPSA argues that the Commission should focus on structural mitigation measures that will address affiliate abuse, in particular, adopting rules precluding all affiliate transactions, except in cases where there is an effective competitive procurement program in place.[136]

133. Others argue that the scope of the mitigation measures should be narrowed. Duke, EEI, FirstEnergy and Southern Companies argue that mitigation should apply only to short-term sales and that the Commission has provided no justification to now require mitigation for long-term sales into relevant markets where the applicant has market power.[137] EEI asserts that, in changing its policy, the Commission relied on comments made primarily by public power groups that were unsupported by evidence. EEI argues that it is a fundamental precept of market economics that new capacity will be brought to

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[134] April 14 Order, 107 FERC ¶ 61,018 at P 151-155.

[135] Request for Rehearing of APPA/TAPS at 38-39.

[136] Request for Rehearing of EPSA at 12-13.

[137] Requests for Rehearing of Duke at 19-20, EEI at 50-54, FirstEnergy at 16-17, Southern Companies at 17-18, 43-45.

the market when there are shortages. To not recognize the potential long-term alternatives to customers will, EEI asserts, leave suppliers found to possess market power in today's short-term market restricted to only offering cost-based pricing for a 10 year contract. EEI therefore urges the Commission to reverse the April 14 Order's presumption that mitigation is warranted in long-term markets, at least until it has sufficiently developed the record on the factual issue of whether mitigation is required in long-term markets.[138] FirstEnergy argues that cost-based limits should not be imposed for long-term power sales agreements based on the evaluation of short-term market conditions, as this will impair competitive market development.[139] Similarly, FirstEnergy and Duke ask the Commission to determine the need for mitigation of long-term sales based on case-by-case evidence that there are impediments to alternative supplies.[140]

134. EEI argues that access to power sold under mitigated prices should be restricted to buyers serving end-use customers within the relevant geographic market in which the applicant has been found to have market power.[141] An applicant should not be required to make sales at mitigated prices to power marketers or brokers without end-use customers in the relevant market.

135. With respect to the section 35.27 exemption, the Joint Consumer Advocates request that the Commission clarify that mitigation measures described in the April 14 Order will apply to facilities for which construction commenced on or after July 9, 1996, if the applicant is found to have market power.[142]

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[138] Request for Rehearing of EEI at 52-55.

[139] Request for Rehearing of FirstEnergy at 16-17, 54.

[140] Request for Rehearing of Duke at 19-20, FirstEnergy at 16-17.

[141] Request for Rehearing of EEI at 50.

[142] Request for Rehearing of Joint Consumer Advocates at 10.

136. Some parties express concern that suppliers with market power would be able to manipulate or game the mitigation measures proposed in the April 14 Order. APPA/TAPS and NRECA submit that the Commission should adopt measures to prevent such gaming, for example, by limiting applicants' discretion in choosing the units used to calculate their incremental costs.[143]

137. Calpine argues that applicants who fail the screens should not be permitted to design their own mitigation measures, as this would be an abdication of the Commission's responsibility to ensure that market-based rates are just and reasonable.[144]

138. Southern Companies argues that mitigation measures are unnecessary because the Commission's Market Behavior Rules are sufficient to alleviate any generation market power.[145] Similarly, FirstEnergy notes that the Market Behavior Rules should be adequate to protect buyers because they prohibit the exercise of market power or the manipulation of markets and provide for sanctions against suppliers that do so.[146]

139. As an alternative to cost-based mitigation, some parties propose market-based mechanisms for mitigating market power. Dominion suggests a market-based default regime under which the marginal clearing prices set in organized and Commission-approved bid-based markets administered by an ISO/RTO serve as the default market-based rate, where feasible.[147] Similarly, EEI proposes that market-based default rates could be determined based on prices at geographically proximate regional competitive energy market hubs or by use of market clearing prices in adjacent ISO/RTOs that have implemented Commission-approved bid-based markets.[148]

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[143] Requests for Rehearing of NRECA at 39-40, APPA/TAPS at 36.

[144] Request for Rehearing of Calpine at 13-14.

[145] Requests for Rehearing of Southern Companies at 46-48 (citing Order Amending Market-Based Rate Tariffs and Authorizations, 105 FERC ¶ 61,218 (2003)).

[146] Request for Rehearing of FirstEnergy at 12.

[147] Request for Rehearing of Dominion at 13.

[148] Request for Rehearing of EEI at 45.

140. Investor-owned utilities submit that the cost-based default mitigation measures are not just and reasonable as they prevent adequate cost recovery and will have negative effects on investment and retail customers.[149] FirstEnergy argues that cost-based mitigation measures may prevent adequate investment in cases where the mitigation price acts as a price cap on all suppliers, discouraging new investment.[150] Cinergy, EEI and FirstEnergy discuss a number of situations where these measures will effectively raise the retail rates of the mitigated entity's customers, while providing a subsidy to those of the buying entity or customers located in a different geographic area.[151]

141. On rehearing certain parties[152] contend that the Commission rejected such a cost plus adder in *PJM Interconnection, L.L.C.*[153]

142. Several parties seek clarification regarding the refund effective date for applicants that fail the screens. EEI asserts that the April 14 Order suggests that the applicant may be at risk from the point when it fails the screens.[154] EEI seeks clarification that an applicant will not face potential refund liability until the Commission has made a definitive determination that the applicant actually possesses market power in a section 206 proceeding on the basis of the modified Delivered Price Test discussed (*i.e.*, using only available economic capacity) and that only revenues collected after the Commission has given notice of its intent to initiate such proceedings will be subject to refund.[155] NRECA seeks clarification as to whether the prospective refund effective date for three-year market-based rate review refers to the refund effective date the Commission will

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[149] Requests for Rehearing of Cinergy at 13, Dominion at 12, Duke at 16-20, Entergy at 26-27, EEI at 44-54, Southern Companies at 41-43.

[150] Request for Rehearing of FirstEnergy at 13.

[151] Requests for Rehearing of Cinergy at 14-15, EEI at 48-49, FirstEnergy at 12-13.

[152] Requests for Rehearing of Cinergy at 13, Dominion at 12, Duke at 16-20, Entergy at 26-27, EEI at 44-54.

[153] 107 FERC ¶ 61,112 (2004) (*PJM*).

[154] Request for Rehearing of EEI at 58.

[155] Requests for Rehearing of EEI at 58-60, FirstEnergy at 6-7.

establish pursuant to a subsequent section 206 proceeding finding the existence of market power, the date the review filing is made, or the date the Commission issues the order taking official notice of the fact that the applicant did not pass the market power screens.[156]

b. Commission Determination

143. APPA/TAPS suggests that the Commission impose structural remedies, including relieving transmission constraints and rules on affiliate transactions, in order to mitigate market power. Our task in establishing this interim approach is to determine whether an applicant may charge market-based rates, not to undertake structural change. Thus, the purpose of the market-based rate analysis specified in our April 14 Order is to examine whether the applicant has the potential to exercise market power in the relevant geographic market. Applicants found not to have market power will be authorized to charge market-based rates. Applicants found to have market power or the presumption of market power will have the appropriate mitigation imposed that eliminates the ability to exercise market power, or authorization to use market-based rates will be revoked. Structural remedies may, however, be proposed as tailored mitigation measures.

144. With regard to APPA/TAPS' request that mitigation measures apply to all geographic areas affected by market power, not just those in the geographic market applied in analyzing the seller's market power, we clarify that mitigation will be imposed in all markets where the applicant is found to have generation market power, or the applicant's market-based rate authorization will be revoked. We also note that concerns with transmission market power, although not part of the generation market power analysis at issue in this case, are examined as part of the total market-based rate application.

145. Duke, EEI, FirstEnergy and Southern Companies argue that the Commission should limit mitigation to short-term sales and that the Commission did not provide justification for the change in policy. We disagree. We determined in our April 14 Order that in markets where we have found the potential for market power and where there are impediments to long-run alternatives (including lumpy generation investment, insufficient transmission access and insufficient access to fuels), the long-term markets are not inherently competitive.[157] Parties appear to have confused contracts entered into today for terms of longer than one year with the development in the long-term of alternative supplies. We explained in our April 14 Order that customers bargaining for

[156] Request for Rehearing of NRECA at 41.

[157] April 14 Order, 107 FERC ¶ 61,018 at P 155.

long-term purchases today may not have credible alternatives to suppliers with market power. For the reasons discussed in our April 14 Order, there often are impediments to development of new supply alternatives. The theoretical possibility that alternatives may develop in coming years provides the customer with limited bargaining power in transacting with a seller that has generation market power today. On rehearing, the parties offer theoretical arguments for the existence of alternative supplies, but such potential may not negate the ability to exercise market power as described by customers and market participants and discussed in our April 14 Order. Therefore, we affirm that where an applicant has been found to have market power, we will on a prospective basis mitigate market power in long-term markets by requiring prior approval for all contracts for long-term wholesale sales and these contracts must be priced on an embedded cost-of-service basis.

146. We reject suggestions that the Commission restrict mitigated applicants to selling power only to buyers serving end-use customers, as we would reject any suggestion that we restrict participation in markets by buyers who have met all requirements of law and their tariff. Our role is to assure customers that sellers who are authorized to sell at market-based rates do not have market power or have adequately mitigated it. Thus we do not believe it is appropriate to determine the third party buyers with whom the seller will transact, nor is it appropriate to restrict, as suggested by EEI, who may buy power from a seller whose sales have been mitigated.

147. As requested by the Joint Consumer Advocates, we clarify that if an applicant is found to have market power in a control area, all sales made in that control area will be subject to the default mitigation (regardless of when the generating facilities were built), unless any Commission-approved case-specific mitigation provides for different treatment.

148. Concerns about the ability of applicants to manipulate or "game" mitigation measures are unsupported and speculative. To the extent a mitigated applicant is believed to be manipulating or circumventing mitigating measures, section 206 of the FPA provides a process for filing a complaint. The potential for market power abuse will be examined on a case-by-case basis in determining the appropriate mitigation to ensure that the applicant's market-based rates are just and reasonable.

149. Calpine argues that applicants who fail the screen should not be allowed to propose their own mitigation measures and that allowing them to do so would be an abdication of the Commission's responsibilities. We recognize that the Commission has to make the final determination as to whether any proposed mitigation measure is effective and produces just and reasonable results. We do not believe that examining alternative mitigation plans will have detrimental effects. The generation market screens are indicative, and the default mitigation method is generic by design. As a result, we

believe it is appropriate to offer applicants and intervenors the opportunity to present facts and evidence specific to the applicant regarding the ability of proposed mitigation methods to eliminate the ability to exercise market power and to propose alternative mitigation plans. Thus, the decision regarding the appropriate mitigation will be made on reasoned consideration of the merits of the case.

150. With regard to comments related to the role of our Market Behavior Rules, we note that those rules are another tool that the Commission employs to protect customers from market power abuse. However, to the extent that an applicant is found to have market power, it is our obligation to ensure that proper safeguards are in place and that result in just and reasonable rates. Accordingly, consistent with our obligations in this regard, we will require such an applicant to adopt the default cost-based rates or other tailored mitigation that we may find appropriate.

151. Dominion and EEI propose market-based mitigation options for suppliers failing the market power screens. Neither Dominion nor EEI have provided adequate justification to support their proposal. However, applicants may propose tailored mitigation that eliminates an applicant's ability to exercise market power and we will examine such proposals on case-by-case basis. In addition, we will further examine market power and mitigation measures in our rulemaking on all aspects of market-based rates, Docket No. RM04-7-000, and parties may provide generic proposals for our consideration.

152. Investor-owned utilities complain that cost-based default mitigation will prevent adequate cost recovery, and are thus not just and reasonable, and will discourage new investment. We are not persuaded by such arguments because our ratemaking policy is designed to provide for recovery of prudently incurred costs plus a reasonable return on investment.

153. In particular, the Commission's ratemaking policy on cost-based rates is designed to track the operations of a utility and all related costs, including costs of fuel and other variable costs for very short-term sales and the longer-term costs of financing, constructing and maintaining infrastructure to provide electricity service for longer-term sales. The design of default rates in our April 14 Order specifically considers cost and operational factors.

154. Further, the cost-based mitigation provided in our April 14 Order is a default option, that is, the applicant may choose to propose the default mechanism or an alternative mitigation mechanism that it believes is more appropriate to individual circumstances and that eliminates the ability to exercise market power. The claims with regard to the effect of mitigation on new investment and retail rates are unsupported and speculative. We note that our cost-based ratemaking policy provides for recovery of

longer-term costs, as discussed above, and the opportunity for the applicants to propose alternative, tailored mitigation measures should allow adequate consideration of the effect on investment and customers. Further, suppliers without other generation in the market would not be required to demonstrate a lack of market power under section 35.27 of the Commission's regulations for new investments, and thus would receive market-based rate authority.

155. The Commission is not persuaded that a 10 percent adder[158] is an inappropriate default mitigation technique to provide for a reasonable margin above incremental cost in sales of power of one week or less.[159] In general, absent market power, such short-term opportunity sales made in a competitive market cover incremental generation costs plus a level of return permitted by the competitive market. As a default mitigation component, incremental costs plus 10 percent represents a conservative proxy for a reasonable margin available in a competitive market.

156. With regard to arguments on rehearing[160] certain parties contend that the Commission rejected such a cost plus adder in *PJM*. Rather than reject the incremental cost plus 10 percent offer cap in *PJM*, the Commission generally upheld its reasonableness and did not disturb its use in the PJM market structure. It is only in the context of unusual cases where a unit is frequently mitigated (80 percent of its run hours), necessary for reliability, and not recovering sufficient revenues to cover its costs, that the Commission found the cost plus 10 percent offer cap to be problematic.[161] In fact, the Commission found the cost plus 10 percent offer cap to be "fair to most generating units."[162] Thus, rather than provide a basis to contest the use of a cost plus 10 percent default mitigation, the Commission's order in *PJM,* to the degree the offer capping

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[158] Amendment to Part 35 of the Regulations Under the Federal Power Act, Limits for Percentage Adders in Electric Rates for Transmission Services, Order No. 84, 45 Fed. Reg. 31,294 (May 7, 1984), FERC Stats. & Regs. ¶ 30,153 (1980), *clarified and reh'g denied*, Order No. 84-A, 12 FERC ¶ 61,017 (1980), *further clarified*, Order No. 84-B, 12 FERC ¶ 61,157 (1980).

[159] April 14 Order, 107 FERC ¶ 61,018 at PP 143-155.

[160] Requests for Rehearing of Cinergy at 13, Dominion at 12, Duke Energy at 16-20, Entergy at 26-27, EEI at 44-54.

[161] PJM, 107 FERC ¶ 61,112 at P 39.

[162] *Id.*, 107 FERC ¶ 61,112 at P 36.

component of its market design is relevant to the issues raised herein, supports the conclusion that such a pricing approach is fair and reasonable for most units. Like *PJM*, if this default mitigation is not appropriate for the applicant's units, an alternative approach can be proposed as set forth in the April 14 Order.

157. In the instant case, the 10 percent adder is to be used only as a backstop or default measure in the event that an applicant does not opt to propose its own mitigation. That said, the Commission recognizes that all available alternatives must be just and reasonable, and we believe that, for this purpose, in the limited instance of sales of power of one week or less, it is just and reasonable to price sales of power at the applicant's incremental cost plus a 10 percent adder.

158. With regard to questions related to the refund effective period in the context of a three-year market-based rate review, if an applicant fails to pass one or both of the indicative screens, the Commission will issue an order initiating a section 206 investigation and establishing the refund effective date. The refund effective date shall not be earlier than sixty (60) days from the date on which notice of the initiation of the section 206 investigation is published in the Federal Register. In the event that the Commission makes a definitive finding of market power, revokes market-based rates and imposes cost-based rate mitigation, sales made on or after the refund effective date will be subject to refund, where the refund floor would be the default cost-based rate or the case-specific cost-based rate approved by the Commission, if any.

2. Size Mitigation

159. The SMA Order imposed a number of measures regarding the mitigation for size, including measures requiring transmission-providing utilities to perform interconnection studies regarding merchant generation and to post certain information on their OASIS sites. In the April 14 Order, the Commission granted rehearing on those measures that were not addressed in Order No. 2003-A and required the posting of optimum generation sites on OASIS for those who are found to have generation market power.[163]

a. Rehearing Requests

160. Calpine urges the Commission to reinstate the mitigation measures contained in the SMA Order by requiring applicants with market power to interconnect merchant generators as network resources if requested by the generator.[164]

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[163] April 14 Order, 107 FERC ¶ 61,018 at P 165-166.

[164] Request for Rehearing of Calpine at 11-13.

b. Commission Determination

161. Calpine has raised no new issues or arguments from those addressed in the April 14 Order nor does it claim that Order No. 2003 is inadequate. Accordingly, we deny Calpine's rehearing request in this regard.

3. Control Mitigation

162. The SMA Order required Entergy and Southern Companies to employ an independent third party to operate and administer their OASIS sites.[165] In the April 14 Order, the Commission granted rehearing of its decision directing Entergy and Southern Companies to employ an independent third-party to operate and administer their OASIS sites, without making any findings with regard to the merits of the arguments raised.[166]

a. Rehearing Requests

163. Calpine and EPSA urge the Commission to require applicants with market power to ensure that third parties are in place to handle certain transmission functions, including the operation of their OASIS sites.[167]

b. Commission Determination

164. We reiterate our determination in our April 14 Order that the requirement to employ an independent third party to operate and administer the OASIS site of an applicant found to have generation market power is more relevant to the discussion of transmission market power. The Commission will appropriately consider this issue in the generic rulemaking proceeding wherein we will conduct a comprehensive review of the appropriate analysis for granting market-based rate authority, including transmission market power concerns.[168] The present proceeding involves generation market power only, hence we reject parties' requests to reinstate transmission control mitigation here.

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[165] *See* SMA Order at section II.G.

[166] April 14 Order, 107 FERC ¶ 61,018 at 175.

[167] Requests for Rehearing of Calpine at 11-13, EPSA at 13.

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

E. ISO/RTO Exemption

165. In the April 14 Order, the Commission granted rehearing with respect to the exemption from the generation market power analysis for sales into an ISO/RTO with Commission-approved market monitoring and mitigation and required all ISO/RTO-located applicants for market-based rate authority to submit the generation market power analyses adopted in the April 14 Order. Furthermore, applicants located in ISO/RTOs with sufficient market structure and a single energy market (*i.e.*, PJM, ISO-NE, NYISO, CAISO) were permitted to use the geographic region under the control of the ISO/RTO as the default relevant geographic market.[169]

1. Rehearing Requests

166. Some parties argue that the Commission did not go far enough in eliminating the ISO/RTO exemption because it still permits ISO/RTO-located applicants to incorporate the ISO/RTO mitigation measures in their market power analyses. These parties argue that this is inappropriate because ISO/RTO mitigation measures are not sufficient to adequately mitigate market power.[170] First, these parties contend that there is little evidence that the mitigation regimes currently in place ensure fully competitive price levels because none of these regimes explicitly considers the possibility of collusion among sellers. Furthermore, ISO/RTO mitigation measures do not apply to markets that are not operated by the ISO/RTOs, such as bilateral and long-term markets.[171] Second, NRECA argues that the Commission's reliance on ISO/RTOs' assertions about the effectiveness of their own mitigation measures is an impermissible delegation of its responsibilities under the FPA to ISO/RTOs. NRECA states that the Commission is obligated to independently verify the effectiveness of ISO/RTO mitigation measures.[172] Finally, according to NRECA, such an approach would make the screens redundant: if the existence of the ISO/RTO's own market monitoring and mitigation schemes are a full remedy mitigating any generation market power, there is no reason to make them run the generation market power screens in the first place.[173]

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[169] April 14 Order, 107 FERC ¶ 61,018 at P 186.

[170] Requests for Rehearing of NRECA at 23-28; New Mexico Attorney General, *et al.* at 12-13.

[171] Requests for Rehearing of APPA/TAPS at 16-20, NRECA at 25-26.

[172] Request for Rehearing of NRECA at 27.

[173] *Id.* at 23.

167. Investor-owned utilities, on the other hand, urge the Commission to reinstate the blanket ISO/RTO exemption, arguing that the Commission has not adequately explained or supported its departure from established policy by imposing the new market power screens for ISO/RTO participants[174] and that the elimination of the exemption creates an undue regulatory burden in areas where market power is already mitigated.[175] These parties argue that there is substantial evidence in the record that Commission-approved ISO/RTOs have effectively performed their market monitoring and mitigation functions, which are further reinforced by Commission oversight and enforcement; the imposition of the market power screens in ISO/RTO markets is thus an unnecessary duplication of existing safeguards. Dominion and EEI also contend that the elimination of the exemption will discourage participation in ISO/RTOs.[176] Finally, EPSA also argues that the lack of such an exemption may give rise to inconsistent approaches to mitigation in ISO/RTO markets because ISO/RTO-located applicants with market power will be free to propose their own tailored mitigation measures, which may or may not be consistent with those in Commission-approved ISO/RTOs.[177]

168. Some of these parties suggest that the change may have been motivated by the Commission's concern that the ISO/RTO exemption was an inappropriate delegation of the Commission's authority under the FPA. EEI and PSEG contend that such a concern is unfounded.[178] PSEG asserts that, under existing judicial precedent, federal agencies may rely on another governmental agency or private entity for assistance in the performance of their statutorily-mandated duties under specific circumstances provided

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[174] Requests for Rehearing of Dominion at 5-10, EEI at 54-57, FirstEnergy at 13-16, PSEG at 3-8.

[175] Requests for Rehearing of Calpine at 16-17, EPSA at 7-8.

[176] Requests for Rehearing of Dominion at 7, EEI at 55.

[177] Request for Rehearing of EPSA at 8.

[178] Requests for Rehearing of EEI at 56-57, PSEG at 4-8.

that certain conditions are satisfied.[179] PSEG contends that the ISO/RTO exemption satisfies these conditions because the Commission retains the sole authority to grant or revoke market-based rates and because the Commission works closely with ISO/RTO market monitoring units to identify and address inappropriate behavior.[180]

169. If the Commission is unwilling to reinstate the ISO/RTO exemption, parties propose a number of alternate solutions. EEI proposes that the Commission should consider waiver requests by individual ISO/RTOs that demonstrate that they have adequate market oversight and mitigation.[181] EPSA argues that the Commission should clarify that applicants located in ISO/RTOs have the ability to expedite their market-based rate application by accepting ISO/RTO-imposed mitigation.[182] PSEG suggests that the Commission should consider performing a three-year review of ISO/RTOs, focusing on the degree of competition in its market and its market monitoring practices and policies. In the event that the ISO/RTO is found to have an adequately competitive market and adequate market monitoring in place, then the Commission would not need to impose the expensive and time consuming generation market power screen on each and every market participant in that region. To the extent that the Commission was not fully satisfied with the ISO/RTO, the Commission would then require each market participant to submit to a thorough review under the Commission's generation market power screen analysis.[183]

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[179] Request for Rehearing of PSEG at 7-8 (citations omitted). According to PSEG, such delegation is permissible where: (1) an agency with broad authority to grant or prohibit certain activities may condition their grant of permission on the decision of another entity; (2) an agency may rely upon an outside entity to provide the agency with factual information provided that the agency does not transfer its decision making authority to the outside entity; and (3) an agency may turn to an outside entity for advice and policy recommendations, provided the agency makes the final decision itself.

[180] *Id.* at 8-9.

[181] Request for Rehearing of EEI at 57.

[182] Request for Rehearing of EPSA at 8.

[183] Request for Rehearing of PSEG at 8.

170. APPA/TAPS commends the Commission for the use of cost-based rates as a default mitigation measure,[184] but suggests other ways in which the scope of mitigation measures should be broadened. First, APPA/TAPS agrees that the Commission should not exempt ISO/RTO-located applicants. APPA/TAPS questions the efficacy of the current ISO/RTO mitigation measures and argues that ISO/RTO mitigation covers only spot market mitigation, but not bilateral market mitigation. APPA/TAPS concludes that the generation market power analysis should function as an outside check on market monitors and ISO/RTO spot market mitigation and that entities found to have generation market power by the Commission should be subject to both ISO/RTO spot market mitigation and long-term mitigation by FERC; in cases where the two overlap, the mitigation measures most protective of customers should apply.[185] Similarly, New Mexico Attorney General, *et al.* argue that, since bilateral contracts are not typically subject to ISO/RTO-administered mitigation measures, the Commission should clarify that applicants for market-based rate authorization for bilateral contracts who fail the screens are all subject to FERC's generic price mitigation rules, whether or not they belong to an ISO/RTO.[186] APPA/TAPS also urges the Commission to clarify that mitigation measures apply to all geographic areas affected by market power, not just those in the relevant geographic market.[187]

171. Some parties argue that the Commission erred in the April 14 Order where it determined that applicants in regions where an ISO/RTO has a sufficient market structure and a single energy market can use the ISO/RTO region as the default relevant geographic market.[188] APPA/TAPS and NRECA both assert that load pockets and internal transmission constraints can give rise to relevant geographic markets smaller than a single control area and/or a single ISO/RTO.[189] Furthermore, NRECA contends that the Commission cannot rely on the existence of market monitoring and mitigation mechanisms in ISO/RTO markets as a rationale for picking an erroneous default relevant

[184] Request for Rehearing of APPA/TAPS at 35.

[185] *Id.* at 20.

[186] Request for Rehearing of New Mexico Attorney General, *et al.* at 12-13.

[187] Request for Rehearing of APPA/TAPS at 34-35.

[188] Request for Rehearing of NRECA at 19.

[189] Requests for Rehearing of NRECA at 19-23, APPA/TAPS at 13-16.

market in the first instance.[190] APPA/TAPS suggests that, in single control area ISO/RTOs, the relevant geographic market delineation should be a rebuttable presumption. In multiple control area ISO/RTOs, the control area presumption should apply while allowing applicants to propose larger or smaller geographic markets based upon specific facts, as is currently the case for control areas that are not part of an ISO/RTO.[191]

172. NSTAR Electric & Gas Corporation (NSTAR) seeks clarification as to whether an applicant with market power selling into an ISO/RTO is automatically subject to that ISO/RTO's mitigation measures or if it has discretion to adopt the April 14 Order's cost-based rate mitigation.[192]

173. Finally, Williams Power Company (Williams) requests clarification as to the allocation of the burden of proof in cases where intervenors challenge the effectiveness of ISO/RTO mitigation measures. The April 14 Order states that applicants who fail the screens may point to ISO/RTO mitigation measures as evidence that their market power has been adequately mitigated, though intervenors may challenge the effectiveness of the ISO/RTO mitigation measures. Williams proposes that intervenors should carry the burden of proof when they do so.[193]

2. Commission Determination

174. We agree with NRECA that the Commission must independently verify the effectiveness of any alternative mitigation measures, including the ISO/RTO mitigation, which would serve to replace the default mitigation adopted in the April 14 Order. NRECA states that exempting all participants in ISO/RTOs would make the screens redundant. We have allowed, however, that any applicant, whether or not a member of an ISO/RTO, can accept a presumption of market power, skip the screens and go directly to mitigation. If a participant in an ISO/RTO points to the mitigation imposed by the ISO/RTO as eliminating the ability to exercise market power, we would analyze this proposal on a case-specific basis, where intervenors would be able to argue that the ISO/RTO mitigation was not sufficient to adequately mitigate the applicant's market power.

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[190] Request for Rehearing of NRECA at 22.

[191] Request for Rehearing of APPA/TAPS at 14.

[192] Request for Rehearing of NSTAR at 9.

[193] Request for Rehearing of Williams at 2.

175. As noted above, several parties, including a number of investor-owned utilities, EPSA and Calpine ask the Commission to reinstate the blanket ISO/RTO exemption, contending: (1) that the elimination creates an undue burden and duplication of mitigation measures; (2) that the ISO/RTOs have performed their market monitoring and mitigation well and making these participants subject to the Commission's screens and mitigation is a duplication of safeguards; and (3) that removing the exemption will remove an incentive to join ISO/RTOs. In response to the first two points, we recognize the benefits of an ISO/RTO that uses appropriate market monitoring and mitigation measures, but believe our indicative screens provide an additional measure to check for the potential of market power. In addition, once we act on a generation market power analysis for a given ISO/RTO, future applicants can rely on that analysis to support their market-based rate applications. On the third point, while an exemption from the generation market power analysis may be viewed as an incentive to join an ISO/RTO, our purpose here is to adopt a process that treats all applicants fairly and equally while protecting customers from unjust and unreasonable rates. Accordingly, we deny the request for rehearing of our determination to eliminate the exemption from the generation market power analysis for sales into an ISO/RTO with Commission-approved market monitoring and mitigation measures.

176. Further, we will not adopt a one-size-fits-all approach, as suggested by some parties, and the requests for tailored mitigation will be considered on a case-by-case basis. EPSA's argument that, due to the lack of a blanket ISO/RTO exemption, case-specific mitigation may lead to inconsistent approaches is premature. Interested parties may intervene at such time as an applicant proposes mitigation that conflicts with the relevant ISO/RTO mitigation.

177. As noted above, some parties claim that the Commission should not have allowed participants in ISO/RTO markets to use that region as the default relative geographic market because internal transmission constraints can give rise to relevant geographic areas smaller than a single control area and/or an entire ISO/RTO. We recognize, however, that the ISO/RTO footprint or control area will not always be the appropriate geographic area to consider and have afforded the opportunity for the default relevant geographic market to be rebutted on a case-specific basis. We note that all ISOs and RTOs have forms of local market power mitigation in place, and this mitigation can be taken into account in the analysis.

178. The April 14 Order stated that:

> [A]pplicants can incorporate the mitigation that 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 his market power had been adequately mitigated.[194]

This may have led to some confusion regarding the default geographic market for applicants that have been determined to have local market power and are subject to specific mitigation within an ISO/RTO (*e.g.*, New York City). We clarify that the example above was only intended to illustrate that an applicant that fails one or both of our indicative screens could present evidence that any market power it may possess is adequately mitigated. We did not intend to imply that an applicant in an ISO/RTO with a single dispatch and commitment needs to perform the indicative screens on a smaller geographic region than the ISO/RTO-wide geographic market. Rather, an applicant may point to ISO/RTO mitigation if it is presumed or found to have market power in the ISO/RTO-wide geographic market, not only in a local market as our example may have suggested.

179. APPA/TAPS supports the April 14 Order's elimination of the ISO/RTO exemption and argues that the current ISO/RTO spot market mitigation is not adequately stringent. However, APPA/TAPS' argument is premature and unpersuasive. An entity in an ISO/RTO that fails the screens, or wishes to go straight to mitigation, may point to ISO/RTO spot market mitigation as adequately mitigating market power. At that time, the Commission will examine applicant's proposal to determine whether the mitigation is sufficient to eliminate the ability to exercise market power.

180. As requested by APPA/TAPS and the New Mexico Attorney General, *et al.*, we clarify that applicants for market-based rate authorization outside of ISO/RTO-operated markets who are found to possess market power are subject to our generic default price mitigation measures, including bilateral contracts, unless we approve an alternative mitigation approach, regardless of membership and participation in ISO/RTO-operated markets in the geographic area.

181. We generally agree with APPA/TAPS that an ISO/RTO is a single market when it is a single control area. However, as stated in our April 14 Order, we believe the key determinant of whether such a region is a single market for purposes of these screens is whether there is a single regional generation unit commitment and dispatch function.

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[194] April 14 Order, 107 FERC ¶ 61,018 at P 189.

Where such a centralized function is operational in a region, generating units may be dispatched to meet load even if they are located multiple subregional control areas away from the load. Thus, the region with single central commitment and dispatch would be considered a single geographic market. In contrast, the role of a control area operator is to identify which generators are eligible to meet real time regulation (load following) needs resulting from the slight variations in load and generation within the control area, but not to coordinate maintenance outages or economically dispatch the available generation with other control areas in the region. Thus, an ISO/RTO with multiple control areas that do not follow a single central unit commitment and dispatch protocol cannot be considered a single market.

182. NSTAR asks whether an applicant with market power selling into an ISO/RTO is automatically subject to the ISO/RTO's mitigation measures or if it can instead adopt the April 14 Order's cost-based rate mitigation. Entities in an ISO/RTO are required to abide by the market rules and tariffs applicable in each ISO/RTO and cannot bypass the ISO/RTO mitigation on transactions in ISO/RTO markets. As a result, on a case-by-case basis, we will address the issue of whether the ISO/RTO mitigation in effect for an applicant that is found to have market power adequately mitigates its market power or whether additional cost-based default price mitigation should be imposed. We expect applicants proposing tailored mitigation will raise this issue within the context of their individual facts and circumstances for the Commission to resolve based on the merits of the case.

183. Williams proposes that the party challenging a market power analysis should carry the burden of proving the ineffectiveness of ISO/RTO mitigation measures. While applicants that fail the screen may point to the ISO/RTO's mitigation as evidence that their market power has been adequately mitigated, this evidentiary showing is not definitive. Applicants still bear the burden of proving that the ISO/RTO measures are effective.

F. Legal Authority

1. Rehearing Requests

184. Entergy and Southern Companies contend that the April 14 Order violates fundamental principles of due process and administrative law insofar as the Commission has failed to comply with the Administrative Procedure Act's notice and comment procedures and failed to provide them with an opportunity to be heard before applying it to them.[195] Entergy argues that the April 14 Order is a new, substantive rule of general

[195] Requests for Rehearing of Entergy at 4-19, Southern Companies at 53-54.

applicability, which requires the institution of notice and comment procedures, rather than merely a procedural rule or statement of policy, because it effects a major change in existing policy and establishes a standard of conduct that has the force of law. Entergy cites the fact that the Commission has simultaneously initiated a generic rulemaking on the same subject matter as a tacit admission by the Commission that it does not have sufficient information before it to make a final and reasoned decision on this subject.[196]

185. With respect to the right to be heard, Entergy states that having an opportunity to file comments in a proceeding does not provide a full opportunity to be heard where the new interim policy is announced by the Commission only after parties have submitted their comments.[197] Instead, Entergy submits that such notice and opportunity to respond must be provided before final agency action and not merely in the reconsideration period or through the appeals process.[198]

186. Finally, Entergy contends that the April 14 Order does not provide a reasoned basis for adopting a second "interim" market power screen pending the completion of the generic rulemaking proceeding. Because there are no exigent circumstances justifying the application of an interim market power test to a selected group of entities, the Commission should instead await the outcome of the generic market-based rates rulemaking in Docket No. RM04-7-000.[199]

2. Commission Determination

187. 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 and by applying the April 14 Order to AEP, Entergy, and Southern Companies without giving those utilities an opportunity to be heard and to respond. As an initial matter, we note that the Commission is not limited to notice and comment rulemaking in developing policy. Agencies generally are permitted considerable discretion to choose whether to

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[196] Request for Rehearing of Entergy at 8-9 (citations omitted).

[197] *Id.* at 9.

[198] *Id.* 12-13.

[199] *Id.* at 16-17.

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.

188. Moreover, 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, including the establishment of the proceeding in Docket No. PL02-8-000, 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 has provided applicants and interested parties multiple opportunities to submit comments in the course of this proceeding, issued a Staff Paper and invited written comments on the Staff Paper, held a technical conference open to applicants and other interested parties, and given interested parties a further opportunity to comment following the technical conference. Therefore, the Commission has provided multiple rounds of notice and opportunity for all interested persons to file comments in these proceedings. We have given careful consideration to the numerous comments received by industry participants in these proceedings, including comments submitted by Entergy and Southern Companies, and adopted in the April 14 Order numerous modifications to the generation market power analysis and related mitigation earlier announced in the SMA Order based on those comments. As a result, we will deny rehearing on this issue.

189. Further, we disagree with Entergy's allegation that we have not provided a reasoned basis for adopting an "interim" market power screen pending the completion of the generic rulemaking proceeding. As we explained in the SMA Order and reiterated in the April 14 Order, the purpose of the generic proceeding is to undertake a comprehensive review of the current four-part test for market-based rate authority.[201] That review will include whether and how that test should be modified to assure that electric market-based rates are just and reasonable under the FPA.[202] In the meantime, pending completion of that review, we determined that it was necessary to adopt a new generation market power analysis on an interim basis. We concluded that, because of

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[200] *See, e.g.,* SEC v. Chenery, 332 U.S. 194, 202-03, *reh'g denied*, 332 U.S. 747 (1947); NLRB v. Beech Nut Lifesavers, Inc., 406 F.2d 253, 257-58 (2d Cir. 1968), *cert. denied*, 394 U.S. 1012 (1969).

[201] SMA Order, 97 FERC ¶ 61,219 at 61,969; April 14 Order, 107 FERC ¶ 61,018 at P 2.

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

significant structural changes and corporate realignments in the electric industry, the hub-and-spoke analysis that the Commission had employed to determine generation market power (the first part of the four-part test to determine whether to grant a public utility market-based rate authority) no longer adequately protected customers against generation market power in all circumstances.[203] 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. On this basis, we determined it was appropriate to adopt a new generation market power analysis on an interim basis to ensure that customers are protected against the exercise of market power in generation, pending completion of the comprehensive generic rulemaking proceeding.

190. Further, Entergy is in error when it claims that the Commission is applying the interim generation market power analysis to only selected entities. As we made clear in the April 14 Order and in the subsequent May 13 Order, 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.

G. Implementation Process

1. Rehearing Requests

191. A number of parties request that the Commission defer compliance with and application of the April 14 Order until a reasonable time after the Commission acts on the requests for rehearing. AEP and Southern Companies request that they be allowed to defer submission of the required generation market power analyses until 30 days after the

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[203] SMA Order, 97 FERC ¶ 61,219 at 61,969; April 14 Order, 107 FERC ¶ 61,018 at P 10.

Commission acts on their requests for rehearing.[204] Entergy requests that the Commission either grant an extension of time to implement the April 14 Order until at least 60 days after the Commission rules on rehearing requests, or alternately, that it should stay the effect of the April 14 Order pending rehearing.[205]

192. Duke argues that the 30 days allotted for rehearing petitions has not provided sufficient time for market participants to fully analyze the concerns about off-peak market power or to propose screens that could provide meaningful results. EEI cites the cost of analyses, potential costs of mitigation, and irreparable harm that would occur if companies comply and then the Commission modifies the new interim screens and mitigation measures.[206]

2. Commission Determination

193. The Commission addressed the requests for extensions of time to comply with the April 14 Order in the June 7 Order. In the June 7 Order, the Commission granted AEP, Entergy and Southern Companies an extension of time to submit their generation market power analysis until 30 days after the Commission issues an order on rehearing of the April 14 Order.[207]

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[204] Requests for Rehearing of AEP at 10, Southern Companies Motion for Extension of Time at 2.

[205] Request for Rehearing of Entergy at 27-36.

[206] Request for Rehearing of EEI at 57-58.

[207] On July 2, 2004, East Texas Electric Cooperative, Inc. (ETEC) and Northeast Texas Electric Cooperatives, Inc. (NTEC) filed a request for rehearing of the June 7 Order. They ask the Commission to grant rehearing of the June 7 Order and either "(1) reinstate the filing dates of the April 14 Order with, perhaps, a short extension of no more than 30 days for AEP to make the requisite filing or (2) provide a date certain, within the next 90 days, for rehearing and require the submission of the required filings within that same 90-day period." Because the instant order directs AEP, Entergy and Southern Companies to file their generation market power analyses within 30 days of the date of issuance of this order, we dismiss as moot ETEC and NTEC's request for rehearing.

The Commission orders:

(A) The Commission hereby denies rehearing of, and grants clarification of, the April 14 Order as discussed in the body of this order.

(B) AEP, Entergy and Southern Companies are directed to file within 30 days of the date of issuance of this order generation market power analyses pursuant to the two indicative screens (pivotal supplier and market share) adopted in the April 14 Order.

By the Commission. Commissioner Kelly not participating.

(S E A L)

Magalie R. Salas,
Secretary.

Appendix A
Requests for Rehearing and/or Clarification

AEP Power Marketing, Inc., AEP Service Corporation, CSW Power Marketing, Inc., CSW Energy Services, Inc. and Central and South West Services, Inc. (AEP)	Request for Rehearing and Clarification, Motions to extend or stay the compliance deadline
American Public Power Association and the Transmission Access Policy Study Group (APPA/TAPS)	Request for Rehearing and Clarification*
Calpine Corporation (Calpine)	Request for Rehearing
Cinergy Services, Inc. (Cinergy)	Request for Rehearing
Dominion Resources, Inc. (Dominion)	Request for Rehearing and Clarification**
Duke Energy Corporation (Duke)	Motion for Clarification and Request for Rehearing
Edison Electric Institute and Alliance of Energy Suppliers (collectively, EEI)	Request for Rehearing
Electric Power Supply Association (EPSA)	Request for Rehearing and Clarification
Entergy Services, Inc. (Entergy)	Request for Rehearing and Expedited Motion for Extension of Time, or in the alternative, Stay Pending Rehearing
FirstEnergy Corp. (FirstEnergy)	Request for Rehearing and Clarification
National Rural Electric Cooperative Association (NRECA)	Request for Rehearing and Clarification
NSTAR Electric & Gas Corporation (NSTAR)	Request for Clarification or, in the Alternative, Rehearing
New Mexico Office of Attorney General, Colorado Office of Consumer Counsel, Utah Committee of Consumer Services, Rhode Island Office of Attorney General, and Rhode Island Division of Public Utilities and Carriers (New Mexico Attorney General, *et al.*)	Request for Rehearing*
Occidental Chemical Corporation (Occidental)	Motion to Intervene out-of-time
PacifiCorp	Motion for Clarification

Pennsylvania Office of Consumer Advocate, Maryland Office of People's Counsel, Ohio Office of Consumer Counsel and Office of People's Counsel for the District of Columbia (collectively, Joint Consumer Advocates)	Request for Rehearing or Clarification**
PSEG Energy Resources & Trade LLC and PSEG Power LLC (PSEG)	Request for Rehearing and Clarification**
Southern Companies	Request for Rehearing and request for stay
Williams Power Company, Inc. (Williams)	Request for Rehearing**
Wisconsin Public Service Corporation, WPS Power Development Inc. and WPS Energy Services (WPS)	Request for Rehearing**

* Of the entities listed as filing a joint rehearing request, only APPA, the Rhode Island Office of Attorney General and Rhode Island Division of Public Utilities and Carriers filed a motion to intervene.

** These entities did not file motions to intervene.