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18 CFR Part 35

Refinements to Policies and Procedures for Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities; Proposed Rules

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket No. RM14–14–000]

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

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is proposing to amend its regulations governing market-based rates for public utilities pursuant to the Federal Power Act (FPA). The Commission is proposing to revise its current standards for market-based rates for sales of electric energy, capacity, and ancillary services to streamline certain aspects of its filing requirements to reduce the administrative burden on applicants and the Commission. The Commission seeks comment on the proposed revisions. In addition, the Commission provides some clarification regarding the standards for obtaining and retaining market-based rate authority.

DATES: Comments are due September 23, 2014.

ADDRESSES: Comments, identified by docket number, may be filed in the following ways:

- Electronic Filing through *http://www.ferc.gov.* Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.
- *Mail/Hand Delivery:* Those unable to file electronically may mail or hand-deliver comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE., Washington, DC 20426.

Instructions: For detailed instructions on submitting comments and additional information on the rulemaking process, see the Comment Procedures Section of this document.

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION:

Table of Contents

I. Introduction

1. Pursuant to sections 205 and 206 of the Federal Power Act (FPA),[1] the Commission is proposing to amend its regulations to revise Subpart H to Part 35 of Title 18 of the Code of Federal Regulations (CFR), which governs market-based rate authorizations for wholesale sales of electric energy, capacity, and ancillary services by public utilities.

II. Background

2. In 1988, the Commission began considering proposals for market-based pricing of wholesale power sales. The Commission acted on market-based rate proposals filed by various wholesale suppliers on a case-by-case basis. Over the years, the Commission developed a four-prong analysis to assess whether a seller should be granted market-based rate authority: (1) Whether the seller and its affiliates lack, or have adequately mitigated, market power in generation; (2) whether the seller and its affiliates lack, or have adequately mitigated, market power in transmission; (3) whether the seller or its affiliates can erect other barriers to entry; and (4) whether there is evidence involving the seller or its affiliates that relates to affiliate abuse or reciprocal dealing.

3. In April 2004, the Commission initiated a rulemaking proceeding to consider the adequacy of its market-based rate analysis and whether and how it should be modified to assure that prices for electric power being sold under market-based rates are just and reasonable under the FPA.[2] At that time, the Commission noted that much had changed in the industry since its analysis was first developed and posed a number of questions that would be explored through a series of technical conferences. Following the technical conferences, the Commission issued a notice of proposed rulemaking that led to the issuance in 2007 of Order No. 697, which clarified and codified the Commission's market-based rate policy.[3]

4. In Order No. 697, the Commission adopted two indicative screens for assessing horizontal market power: The pivotal supplier screen and the wholesale market share screen (with a 20 percent threshold), each of which serves as a cross check on the other to determine whether sellers may have market power and should be further examined.[4] The Commission stated that passage of both indicative screens establishes a rebuttable presumption that the seller does not possess horizontal market power. Sellers that fail either indicative screen are rebuttably presumed to have market power and are given the opportunity to present evidence through a delivered price test (DPT) analysis demonstrating that, despite a screen failure, they do not have market power.[5] The Commission uses a ''snapshot in time'' approach based on historical data for both the indicative screens and the DPT analysis.[6]

5. With respect to the horizontal market power analysis, in traditional markets (outside regional transmission organization/independent system operator (RTO/ISO) markets),[7] the default relevant geographic market for purposes of the indicative screens is first, the balancing authority area(s) where the seller is physically located, and second, the markets directly interconnected to the seller's balancing authority area (first-tier balancing authority areas).[8] Generally, sellers that are located in and are members of the RTO may consider the geographic region under the control of the RTO as the default relevant geographic market for purposes of the indicative screens.[9]

6. With respect to the vertical market power analysis, in cases where a public utility or any of its affiliates owns, operates, or controls transmission facilities, the Commission requires that there be a Commission-approved Open Access Transmission Tariff (OATT) on file, or that the seller or its applicable affiliate has received waiver of the OATT requirement, before granting a seller market-based rate authorization.[10] The Commission also considers a seller's ability to erect other barriers to entry as part of the vertical market power analysis.[11] As such, the Commission requires a seller to provide a description of its ownership or control of, or affiliation with an entity that owns or controls, intrastate natural gas transportation, storage or distribution facilities; sites for generation capacity development; and physical coal supply sources and ownership of or control over who may access transportation of coal supplies (collectively, inputs to electric power production).[12] In Order No. 697–C, the Commission revised the change in status reporting requirement in § 35.42 of the Commission's regulations to require market-based rate sellers to report the acquisition of control of sites for new generation capacity development on a quarterly basis instead of within 30 days of the acquisition.[13] The Commission adopted a rebuttable presumption that the ownership or control of, or affiliation with any entity that owns or controls, inputs to electric power production does not allow a seller to raise entry barriers but will allow intervenors to demonstrate otherwise.[14] Finally, as part of the vertical market power analysis, the Commission also requires sellers to make an affirmative statement that they have not erected barriers to entry into the relevant market and will not erect barriers to entry into the relevant market. The Commission clarified that the obligation in this regard applies to both the seller and its affiliates but is limited to the geographic market(s) in which the seller is located.[15]

7. If a seller is granted market-based rate authority, the authorization is conditioned on: (1) Compliance with affiliate restrictions governing transactions and conduct between power sales affiliates where one or more of those affiliates has captive customers;[16] (2) a requirement to file post-transaction electric quarterly reports (EQR) with the Commission containing: (a) A summary of the contractual terms and conditions in

[1] 16 U.S.C. 824d, 824e (2012).

[2] *Market-Based Rates for Public Utilities,* 107 FERC ¶ 61,019, at P 1 (2004) (initiating rulemaking proceeding).

[3] *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities,* Order No. 697, FERC Stats. & Regs. ¶ 31,252, *clarified,* 121 FERC ¶ 61,260 (2007) (Clarifying Order), *order on reh'g,* Order No. 697–A, FERC Stats. & Regs. ¶ 31,268, *clarified,* 124 FERC ¶ 61,055, *order on reh'g,* Order No. 697–B, FERC Stats. & Regs. ¶ 31,285 (2008), *order on reh'g,* Order No. 697–C, FERC Stats. & Regs. ¶ 31,291 (2009), *order on reh'g,* Order No. 697–D, FERC Stats. & Regs. ¶ 31,305 (2010), *aff'd sub nom. Mont. Consumer Counsel v. FERC,* 659 F.3d 910 (9th Cir. 2011), *cert. denied,* 133 S. Ct. 26 (2012).

[4] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 62.

[5] *Id.* P 13; 18 CFR 35.37(c)(3).

[6] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 17.

[7] We will use the term ''RTO'' when referring to either an RTO or ISO for easier readability.

[8] The Commission also noted that ''[w]here a generator is interconnecting to a non-affiliate owned or controlled transmission system, there is only one relevant market (i.e., the balancing authority area in which the generator is located).'' Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 232 n.217.

[9] Where the Commission has made a specific finding that there is a submarket within an RTO, that submarket becomes a default relevant geographic market for sellers located within the submarket for purposes of the market-based rate analysis. *See id.* PP 15, 231.

[10] *Id.* P 408.

[11] *Id.* P 440.

[12] Order No. 697–A, FERC Stats. & Regs. ¶ 31,268 at P 176.

[13] Order No. 697–C, FERC Stats. & Regs. ¶ 31,291 at P 18; 18 CFR 35.42(d).

[14] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 446; 18 CFR 35.37(c).

[15] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 447.

[16] 18 CFR 35.39.

every effective service agreement for market-based power sales; and (b) transaction information for effective short-term (less than one year) and long-term (one year or longer) market-based power sales during the most recent calendar quarter; [17] (3) a requirement to file any change in status that would reflect a departure from the characteristics the Commission relied upon in granting market-based rate authority; [18] and (4) a requirement for large sellers to file updated market power analyses every three years.[19]

8. In Order No. 697, the Commission created two categories of sellers.[20] Category 1 sellers are wholesale power marketers and wholesale power producers that own or control 500 megawatts (MW) or less of generation in aggregate per region; that do not own, operate, or control transmission facilities other than limited equipment necessary to connect individual generation facilities to the transmission grid (or have been granted waiver of the requirements of Order No. 888 [21]); that are not affiliated with anyone that owns, operates, or controls transmission facilities in the same region as the seller's generation assets; that are not affiliated with a franchised public utility in the same region as the seller's generation assets; and that do not raise other vertical market power issues.[22] Category 1 sellers are not required to file regularly scheduled updated market power analyses. Sellers that do not fall into Category 1 are designated as Category 2 sellers and are required to file updated market power analyses.[23] However, the Commission may require an updated market power analysis from any market-based rate seller at any time, including those sellers that fall within Category 1.[24]

9. In Order No. 697, the Commission further stated that through its ongoing oversight of market-based rate authorizations and market conditions, the Commission may take steps to address seller market power or modify rates. For example, based on its review of updated market power analyses, EQR filings, or notices of change in status, the Commission may institute a proceeding under section 206 of the FPA to revoke a seller's market-based rate authorization if it determines that the seller may have gained market power since its original market-based rate authorization. The Commission also may, based on its review of EQR filings or daily market price information, investigate a specific utility or anomalous market circumstance to determine whether there has been a violation of RTO market rules or Commission orders or tariffs, or any prohibited market manipulation, and take steps to remedy any violations.[25]

10. As discussed below, after over six years of experience with the implementation of Order No. 697, we propose certain changes and clarifications in order to streamline and simplify the market-based rate program, and to enhance and improve the program's processes and procedures. Based on our experience, we have found that the burdens associated with certain of our requirements may outweigh the benefits in certain circumstances. For these reasons, we propose a number of changes to the market-based rate program which, taken as a whole, will reduce the burden on industry and the Commission, while continuing to ensure that the standards for market-based rate sales of electric energy, capacity and ancillary services result in sales that are just and reasonable. We also include several specifications and propose a number of minor changes that will add clarity to, and improve transparency in, the market-based rate program.

Summary of Proposals

11. Although we intend to retain the horizontal indicative screens, we propose certain modifications to our horizontal market power analysis. First, we propose to allow sellers in RTO markets to address horizontal market power issues in a streamlined manner that would not involve the submission of indicative screens if the seller relies on Commission-approved monitoring and mitigation to prevent the exercise of market power. We also propose to clarify that where all generation capacity owned or controlled by a seller and its affiliates in the relevant balancing authority areas (including first-tier balancing authority areas or markets) is fully committed, sellers may explain that their capacity is fully committed in lieu of submitting indicative screens as part of their horizontal market power analysis.

12. While we are retaining the definition of the default geographic market for the vast majority of sellers, we are proposing a redefined default relevant geographic market for an independent power producer (IPP) with generation capacity located in a generation-only balancing authority area. We propose that, instead of the default geographic market being the generation-only balancing authority area where its generation is located, the IPP's default geographic market(s) will be the balancing authority area(s) of each transmission provider to which the generation-only balancing authority area is directly interconnected.

13. In Order No. 697, the Commission adopted standard indicative screen formats for submitting a horizontal market power analysis. We propose to add rows to the indicative screen format for sellers to specify Simultaneous Transmission Import Limit (SIL) Values, Long-Term Firm Purchases (from outside the study area), and Remote Capacity (from outside the study area), as well as modifications to the descriptive text of the rows to make them more consistent. We further propose to revise the regulations to require that sellers file the indicative screens in a workable electronic spreadsheet format. We also propose to revise the Commission's regulations to codify the requirement, first discussed in *Puget Sound Energy, Inc.,*[26] that sellers submitting SIL studies adhere to the direction and required format for Submittals 1 and 2 found on the Commission's Web site and that sellers submit Submittals 1 and 2 in a workable electronic spreadsheet format.

14. The Commission previously stated that sellers could make simplifying assumptions such as ''performing the indicative screens assuming no import capacity.'' We clarify that ''assuming no import capacity'' means a seller may assume that there is no *competing* import capacity from the first-tier balancing authority areas or markets.

15. The Commission generally permits sellers submitting indicative screens to rate their generation facilities using either nameplate or seasonal capacity ratings. In addition, the Commission allows sellers with energy-limited resources, such as hydroelectric and wind generation facilities, to use a five-year average capacity factor. We

[17] 18 CFR 35.10b.

[18] 18 CFR 35.42.

[19] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 3; 18 CFR 35.37(a)(1).

[20] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 848.

[21] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities,* Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g,* Order No. 888–A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g,* Order No. 888–B, 81 FERC ¶ 61,248 (1997), *order on reh'g,* Order No. 888–C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group* v. *FERC,* 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York* v. *FERC,* 535 U.S. 1 (2002).

[22] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 849 n.1000; 18 CFR 35.36(a).

[23] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 850.

[24] *Id.* P 853.

[25] *Id.* P 5.

[26] *Puget Sound Energy, Inc.,* 135 FERC ¶ 61,254, Appendix B (2011) (*Puget*).

propose to include solar technologies as energy-limited generation resources. We further propose that sellers with energy-limited resources that do not have five years of historical data may use regional capacity factor estimates appropriate to the specific technology as derived by the United States Energy Information Administration (EIA) to determine the capacity for those resources. We also propose to clarify that a seller must use the same capacity rating methodology for similar generation assets throughout a particular filing.

16. The Commission has stated that a seller's uncommitted capacity is determined by adding the nameplate or seasonal capacity of generation owned or controlled through contract and long-term firm capacity purchases, less operating reserves, native load commitments, and long-term firm sales. Therefore, sellers have been reporting their long-term firm purchases as part of their capacity if the purchase granted them control of that capacity. We propose to require sellers to report all of their long-term firm purchases of capacity and/or energy in their indicative screens and asset appendices, regardless of whether the seller has operational control over the generation capacity supplying the purchased power. This approach will help size the market correctly and will establish consistent treatment of long-term firm sales and long-term firm purchases.

17. The Commission's vertical market power analysis examines affiliation, ownership or control of inputs to electric power production, including sites for generation capacity development. In this Notice of Proposed Rulemaking (NOPR), we propose to eliminate the requirement that sellers provide information on sites for generation capacity development in their market-based rate applications and triennial updated market power analyses and to similarly relieve sellers of their obligation to file quarterly land acquisition reports.

18. The Commission requires that sellers report to the Commission any change in status that would reflect a departure from the characteristics the Commission relied upon in granting market-based rate authority. We propose to revise the regulations to clarify that the 100 MW reporting threshold for filing a notice of change in status is not limited to markets previously studied; thus if a seller acquires generation that causes a cumulative net increase of 100 MW or more in *any* relevant geographic market, the seller must file a notice of change in status. We also propose to revise the regulations to include long-term firm purchases of capacity and/or energy in calculating the 100 MW change in status threshold. Although there currently is no threshold for reporting a change in status that results in a new affiliation, we propose to revise the regulations to include a 100 MW threshold for reporting new affiliations.

19. The Commission requires that sellers include with each new application, market power analysis, and relevant change in status notification an asset appendix that lists all affiliates that have market-based rate authority and identifies assets owned or controlled by the seller and its affiliates. We propose to revise the asset appendix by revising the headings of several columns to be more clear and consistent. We also propose several clarifications to the asset appendix requirements. In particular: (1) A seller must enter the entire amount of a generator's capacity, even if the seller only owns part of the generator; (2) a seller must list one of three specified uses for assets in the asset list containing electric transmission and intrastate gas assets; and (3) sellers should not list assets in which passive ownership interests have been claimed. We also propose to modify the asset appendix to add a new column in the list of transmission assets for the citation to the Commission order accepting the OATT or granting waiver of the OATT requirement. We further propose to require that sellers submit the asset lists in an electronic spreadsheet format that can be searched, sorted, and accessed using electronic tools. We also seek comment on whether it would be useful to develop a comprehensive searchable public database of the information contained in the asset appendix, which sellers could access to update their asset appendices.

20. There are two categories of market-based rate sellers. Category 1 sellers are exempt from the requirement to automatically submit updated market power analyses every three years. Market-based rate Category 2 sellers are required to submit an updated market power analysis every three years according to a regional schedule. We include an updated schedule and region map as part of this NOPR.

21. One of the criteria that must be satisfied to be a Category 1 seller in a region is that the seller and its affiliates must own or control 500 MW or less of generation in aggregate in that region. We propose to codify in the Commission's regulations a distinction in determining seller category status for power marketers and power producers. For each region, a power marketer should include all affiliated generation in that region, while a power producer would only need to include affiliated generation capacity that is located in the same region as the power producer's generation asset(s). We propose this difference in treatment based on the fact that a power marketer is assumed to have no home market, while it is assumed that a majority of a power producer's sales will be in market(s) in which it owns generation assets.

22. While sellers have been required to describe their affiliates and upstream owners when filing initial applications, updated market power analyses and notices of change in status involving new affiliations, we propose to add a requirement in the regulations that sellers provide an organizational chart as well. We propose that the organizational chart be similar to that which we require from FPA section 203 applicants.

23. Although we have previously explained that joint filers are permitted to designate one market-based rate seller to file a single, joint master corporate market-based rate tariff for inclusion in the Commission's eTariff database that reflects the joint tariff for all affiliated sellers, many sellers have not taken advantage of the option to file a joint master corporate market-based rate tariff. We propose to clarify on the Commission's Web site how a corporate family that chooses to submit a joint master corporate tariff should identify its designated filer and what each of the other filers should submit into their respective eTariff databases.

24. We also propose to provide clarification regarding several issues related to how to perform SIL studies and regarding the associated Submittals 1 and 2. In particular, we propose to clarify issues relating to what is meant by Open Access Same-Time Information System (OASIS) practices, how to deal with conflicts between OASIS practices and Commission direction provided in Appendix B of *Puget,* and what is the correct load value to use in the SIL study.

25. The Commission has previously stated that the methodology a transmission provider uses to calculate SIL values must be consistent with the methodology it uses for calculating and posting available transmission capability (ATC) and for evaluation of firm transmission service requests. We propose to clarify that ''OASIS practices'' refers to the seasonal benchmark power flow case modeling assumptions, study solution criteria, and operating practices historically used by the first-tier and study area transmission providers to calculate and post ATC and to evaluate requests for

firm transmission service. We further propose to clarify that in performing a SIL study, the transmission provider must follow its OASIS practices consistent with the administration of its tariff. Thus, the seasonal benchmark power flow cases submitted with a SIL study should represent historical operating practices only to the extent that such practices are available to customers requesting firm transmission service. We clarify that where there is a conflict between the transmission provider's tariff or OASIS practices and the Commission's directions in *Puget,* sellers should follow OASIS practices except where use of actual OASIS practices is incompatible with an analysis of import capability from an aggregated first-tier area. We also remind sellers that the calculated SIL value should account for any limits defined in the tariff, such as stability or voltage. We reiterate that sellers may use load scaling to perform a SIL study if they use load scaling in their OASIS practices as long as they submit adequate support and justification for the scaling factor used and how the resulting SIL value compares had the seller used a generation-shift methodology. We also instruct sellers to subtract all long-term firm import transmission reservations, including reservations held by non-affiliated sellers, from the simultaneous total transfer capability (simultaneous TTC) value. Finally, we clarify that the seller should reduce the simultaneous TTC value by subtracting all wheel through transactions used to serve non-affiliated load embedded in the study area using first-tier area generation. These transactions should be accounted for as long-term firm transmission reservations and reported in Submittal 2.

26. We propose to amend Submittal 1 to revise Row 8 to read ''Adjusted Historical Peak Load'' and propose to direct sellers to include all load associated with the balancing authority area(s) within the study area, including non-affiliated load. Submittal 1 requires sellers to use FERC Form No. 714 load values or explain the source of the data used. We seek comment on the appropriate source of historical peak load data.

27. We propose to clarify that where a first-tier market or balancing authority area is directly connected to the study area only by controllable tie lines and is not connected to any other first-tier market or balancing authority area, sellers should follow their OASIS practice regarding calculation and posting of ATC for such areas. If the seller's OASIS practices are incompatible with the SIL study, entities may use an alternative process to account for import capability for such tie lines.

28. We propose to provide standard guidance for data submittals and representations that sellers using the simultaneous TTC must provide, including historical data of actual, hourly, real-time TTC values used for operating the transmission system and posting availability on OASIS for each interface during each seasonal study period. We propose to clarify that sellers may use the maximum sum of TTC values for any day and time during each season as long as they demonstrate that these TTC values are simultaneously feasible. Finally, we reiterate that, if there are limited interconnections between first-tier markets, we will review evidence that potential loop flow between first-tier areas is properly accounted for in the underlying SIL values and we clarify that simply attesting that first-tier markets or balancing authority areas are not directly interconnected is not sufficient evidence that TTC values posted on OASIS are simultaneous.

29. We note that there are certain waivers that the Commission has granted to certain sellers with market-based rate authority, e.g., power marketers and independent or affiliated power producers, such as waiver of the Uniform System of Accounts requirements, specifically waiver of Parts 41, 101, and 141 of the Commission's regulations except §§ 141.14 and 141.15. We clarify that any waiver of Part 101 granted to a market-based rate seller is limited such that waiver of the provisions of Part 101 that apply to hydropower licensees is not granted with respect to licensed hydropower projects. The Commission further directs that, to the extent that a hydropower licensee has been granted waiver of Part 101 as part of its market-based rate authority, the licensee's market-based rate tariff limitations and exemptions section should be revised to provide that the seller has been granted waiver of Part 101 of the Commission's regulations with the exception that waiver of the provisions that apply to hydropower licensees has not be granted with respect to licensed hydropower projects. Similarly, hydropower licensees that have been granted waiver of Part 141 as part of their market-based rate authority should ensure that the limitations and exemptions section of their market-based rate tariffs specify that waiver of Part 141 has been granted, with the exception of §§ 141.14 and 141.15.

30. The Commission's regulations require as part of the vertical market power analysis that sellers make an affirmative statement that they have not erected barriers to entry into the relevant market and will not erect barriers to entry into the relevant market. We propose to revise the regulations to make it clear that the obligation to make the affirmative statement applies to both the seller and its affiliates.

III. Discussion

A. Horizontal Market Power

1. Sellers in RTOs

a. Current Policy

31. Section 35.37 of the Commission's regulations requires market-based rate sellers to submit market power analyses: (1) When seeking market-based rate authority; (2) every three years for Category 2 sellers; and (3) at any other time the Commission requests a seller to submit an analysis. A market power analysis must address a seller's potential to exercise horizontal and vertical market power. If a seller studying an RTO as a relevant geographic market (RTO seller) fails the indicative screens for the RTO, it can seek to obtain or retain market-based rate authority by relying on Commission-approved RTO monitoring and mitigation.[27]

32. In 2001, the Commission originally proposed that all sales, including bilateral sales, into an RTO with Commission-approved market monitoring and mitigation would be exempt from the generation market power analysis in effect at that time (the Supply Margin Assessment test) and, instead, would be governed by the specific thresholds and mitigation provisions approved for the particular market.[28] However, the Commission subsequently concluded that it would no longer exempt sellers located in markets with Commission-approved market monitoring and mitigation from providing generation market power analyses, on the basis that requiring sellers located in such markets to submit indicative screens provides an additional check on the potential for market power.[29]

[27] In Order No. 697–A, FERC Stats. & Regs. ¶ 31,268 at P 111, the Commission stated that ''to the extent a seller seeking to obtain or retain market-based rate authority is relying on existing Commission-approved [RTO] market monitoring and mitigation, we adopt a rebuttable presumption that the existing mitigation is sufficient to address any market power concerns.''

[28] *AEP Power Marketing, Inc.,* 97 FERC ¶ 61,219, at 61,970 (2001).

[29] *AEP Power Marketing, Inc.,* 107 FERC ¶ 61,018, at P 186 (April 14, 2004 Order), *order on reh'g,* 108 FERC ¶ 61,026 (2004).

33. In Order No. 697, the Commission declined the request that it reinstate the prior RTO exemption, stating it ''will continue to require generation market power analyses from all sellers, including those in [RTO] markets.'' [30] In Order No. 697–A, the Commission denied requests to reconsider its decision stating that

> the dual protections of individual market power analyses and mitigation rules of the [RTOs] provide the Commission with better ability to discern and protect against potential market power. While, as discussed below, mitigation rules for the individual [RTOs] in most cases should be sufficient to guard against the exercises of market power, we are not comfortable at this time with dispensing of the requirement for sellers in [RTOs] to provide us with horizontal market power analyses. Any administrative burden of submitting such analyses is outweighed by the additional information gleaned with respect to a specific seller's market power.[31]

34. Since the issuance of Order No. 697, it has been the Commission's practice to grant sellers market-based rate authority or allow them to retain market-based rate authority where they have failed indicative screens in an RTO but have relied on Commission-approved monitoring and mitigation.[32] RTO sellers are sellers that study an RTO as a relevant geographic market, including those that sell bilaterally. While the burdens of preparing the indicative screens are not necessarily greater for RTO sellers than for sellers in other markets, the submission of indicative screens yields little practical benefit since it has been the Commission's practice to allow RTO sellers that fail the indicative screens to rely on RTO monitoring and mitigation. Thus, for sellers in RTOs, the burden of submitting indicative screens may not be ''outweighed by the additional information gleaned with respect to a specific seller's market power.'' [33]

b. Proposal

35. We propose to modify the approach taken in Order No. 697 to reflect current practice and reduce the burden on these sellers. Specifically, we propose to allow market-based rate sellers in RTO markets with Commission-approved monitoring and mitigation to address horizontal market power issues in a streamlined manner when submitting initial applications requesting market-based rate authority and updated market power analyses. We note that this proposal includes RTO sellers who may have bilateral contracts not subject to the Commission-approved monitoring and mitigation. We find that the existence of monitoring and mitigation in an organized market generally results in a market where prices are transparent.[34] This disciplines forward and bilateral markets by revealing a benchmark price and keeping offers competitive. For example, if a seller offers what a buyer perceives as a non-competitive price in the bilateral market, that buyer can opt to purchase in the spot market. This provides a strong incentive for the seller to offer at a competitive price in the forward and bilateral markets.

36. Under this streamlined approach, RTO sellers would not have to submit indicative screens as part of their horizontal market power analyses if they rely on Commission-approved monitoring and mitigation to prevent the exercise of market power. Rather, to address horizontal market power effects, RTO sellers instead would simply state that they are relying on such mitigation to address any potential market power they might have, and provide an asset appendix and describe their generation and transmission assets. Under this proposal, all RTO sellers seeking market-based rate authority in an RTO market would make an initial filing, consistent with current practice, and those sellers required to file updated market power analyses every three years (i.e., Category 2 sellers) would continue to make their scheduled filings. To address horizontal market power effects, both the initial applications for market-based rate authorization and the updated market power analyses would include: (1) A statement that the seller is relying on RTO mitigation to address any potential market power it might have; (2) identification and description of generation and transmission assets; and (3) an asset appendix.[35] In all scenarios, the Commission would retain the ability to require an updated market power analysis, including indicative screens, from any market-based rate seller at any time.

37. Thus, we propose to add a paragraph to the end of § 35.37(c) (regarding horizontal market power), making it paragraph (c)(6) under this subsection, to read as follows: *In lieu of submitting the indicative screens, Sellers in regional transmission organization and independent system operator markets with Commission-approved market monitoring and mitigation must include a statement that they are relying on such mitigation to address any potential horizontal market power concerns.*

38. In addition, we note that market-based rate sellers are not required by Order No. 697 or the regulations to provide indicative screens in their horizontal market power analyses when submitting change in status filings.[36] In Order No. 697–A, the Commission stated:

> The existing [change in status] reporting requirement provides the Commission a sufficient tool to allow it to assess whether there is a potential market power concern and, if so, the Commission reserves the right to require the seller to submit a market power study. In addition, the seller is required to provide an affirmative statement as to what effect, if any, the added generation has on its market power. *For a seller to make such an affirmative statement, it must determine what effect the added generation has on the market power analysis.* To the extent the seller makes an affirmative statement that there is no effect on its market power, it is bound to that statement and faces remedial action, including civil penalties, if it has misrepresented the effect.[37]

39. Historically, when a change in status filing has created the likelihood that a seller would fail an indicative screen, the seller has often voluntarily

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[30] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 290.

[31] Order No. 697–A, FERC Stats. & Regs. ¶ 31,268 at P 110.

[32] *See, e.g., Niagara Mohawk Power Corp.,* 123 FERC ¶ 61,175, at P 28 (2008) (failures in the New York City and Long Island submarkets of the New York Independent System Operator, Inc.); *Dominion Energy Marketing, Inc.,* 125 FERC ¶ 61,070, at PP 26–27 (2008) (failures in the Connecticut submarket of ISO New England, Inc.); *PSEG Energy Resources & Trade LLC,* 125 FERC ¶ 61,073, at PP 31–32 (2008) (failures in the PJM-East submarket). There are also numerous delegated letter orders granting a seller market-based rate authority where the seller relies on Commission-approved monitoring and mitigation in RTO markets. *See, e.g., TransCanada Energy Marketing ULC,* Docket No. ER07–1274–001 (Jan. 23, 2009) (delegated letter order). Finally, the Commission has not initiated any investigations pursuant to section 206 of the FPA for any RTO sellers failing indicative screens since the issuance of Order No. 697; in all cases where RTO sellers failed, the Commission relied on the Commission-approved monitoring and mitigation to prevent the seller's ability to exercise any potential market power.

[33] Order No. 697–A, FERC Stats. & Regs. ¶ 31,268 at P 110.

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

[35] Applicants making these filings would continue to be required to provide the following information that is related to the *non*-horizontal market power issues: (1) A standard vertical market power analysis; (2) category status representations; (3) a demonstration that sellers continue to lack captive customers in order to support obtaining or retaining a waiver of the affiliate restrictions, if requested; and (4) any other information that is required for that particular filing.

[36] Order No. 697–A, FERC Stats. & Regs. ¶ 31,268 at P 506 (''[W]e will not require entities to automatically file an updated market power analysis with their change in status filings. . . . Furthermore, regardless of the seller's representation, if the Commission has concerns with a change in status filing (for example, market shares are below 20 percent, but are relatively high nonetheless), the Commission retains the right to require an updated market power analysis at any time.'').

[37] *Id.* P 505 (emphasis added).

submitted indicative screens in order to determine the effect of the change on its market power. We clarify that, with this proposed streamlined approach, an RTO seller need not submit indicative screens with its change in status filing even where it may have market power. Instead, the seller may state that it is relying on Commission-approved monitoring and mitigation to mitigate any potential market power it may have. However, the Commission still reserves the right to require an updated market power analysis at any time.

40. We seek comment on this proposal.

2. *Sellers With Fully-Committed Long-Term Generation Capacity*

a. Current Policy

41. The Commission has found that, if generation is committed to be sold on a long-term firm basis to one or more buyers and cannot be withheld by a seller, it is appropriate for a seller to deduct such capacity when performing the indicative screens. In Order No. 697–A, the Commission stated:

> once capacity is committed long-term, regardless of how that capacity is priced (e.g., whether linked to spot prices or not), the ability of the firm to use that capacity to exercise market power in the spot market is severely limited or non-existent. The ability to collude will be determined by the remaining uncommitted capacity in the spot market, not the capacity that is already committed under long-term contracts. Therefore, we conclude that it is appropriate to subtract capacity committed under long-term contracts when calculating a seller's uncommitted capacity for purposes of performing the indicative screens.[38]

42. Thus, the capacity dedicated to long-term firm power sales should be deducted from seller and affiliate capacity in Row C (Long-Term Firm Sales) of the standard screen format provided in Appendix A to Subpart H of Part 35 for submitting the indicative screens.[39] However, some sellers have filed indicative screens in which they did not deduct their fully-committed capacity or incorrectly reported capacity as fully committed when it was only committed for some seasons, for less than one year, or under certain market conditions.[40] Moreover, some sellers have argued that there is no need to perform indicative screens when they can demonstrate that all of their capacity is committed under long-term contract.

b. Proposal

43. It is the Commission's policy to study uncommitted generation capacity in the indicative screens.[41] Currently, the seller's owned or controlled capacity in megawatts is entered into the indicative screens and the fully-committed long-term (one year or longer) capacity is then deducted. If all of the seller and its affiliates' capacity in the relevant balancing authority areas or markets including first-tier balancing authority areas or markets is fully committed, this exercise results in a purely mathematical task (netting to zero uncommitted capacity), thus providing no significant additional information. Therefore, we clarify that where all generation owned or controlled by a seller and its affiliates in the relevant balancing authority areas or markets including first-tier balancing authority areas or markets is fully committed, sellers may explain that their capacity is fully committed in lieu of including indicative screens in their filings in order to satisfy the Commission's market-based rate requirements regarding horizontal market power. The Commission proposes to clarify that, in order to qualify as ''fully committed,'' a seller must commit the capacity so that none of the excluded capacity is available to the seller or its affiliates for one year or longer.

44. We propose that sellers claiming that all of their relevant capacity[42] is ''fully committed'' would have to include the following information: The amount of generation capacity that is fully committed, the names of the counterparties, the length of the long-term contract, the expiration date of the contract, and a representation that the contract is for firm sales for one year or longer. In order to qualify as fully committed, the commitment of the generation capacity cannot be limited during that 12-month consecutive period in any way, such as limited to certain seasons, market conditions, or any other limiting factor. Furthermore, a seller's generation would not qualify as ''fully committed'' if, for example, the seller has generation necessary to serve native load, provider of last resort obligations, or a contract that could allow the seller to reclaim, recall, or otherwise use the capacity and/or energy or regain control of the generation under certain circumstances (such as transmission availability clauses).

45. Finally, consistent with the existing regulations, a change in status filing will be required when a long-term firm sales agreement expires if it results in a net increase of 100 MW or more.[43]

46. We seek comment on these proposals.

3. Relevant Geographic Market for Certain Sellers in Generation-Only Balancing Authority Areas

a. Current Policy

47. The Commission stated in Order No. 697 that ''the horizontal market power analysis centers on and examines the balancing authority area where the seller's generation is physically located''[44] and that the default relevant geographic market (default market) under both indicative screens ''will be first, the balancing authority area where the seller is physically located [the seller's home balancing authority area], and second, the markets directly interconnected to the seller's balancing authority area (first-tier balancing authority area markets).''[45] However, the Commission also noted that ''[w]here a generator is interconnecting to a non-affiliate owned or controlled transmission system, there is only one relevant market (i.e., the balancing authority area in which the generator is located).''[46] Similarly, the Commission continued to require RTO sellers ''to consider, as part of the relevant market, only the relevant [RTO] market and not first-tier markets to the [RTO].''[47]

48. The Commission further stated in Order No. 697 that a ''balancing authority area means the collection of generation, transmission, and loads

[38] *Id.* P 41.

[39] 18 CFR 35.37(c)(4). We note that the market share screen was inadvertently deleted from Appendix A to Subpart H of Part 35 at the time that the Commission made a correction to the pivotal supplier screen in Order No. 697–A. *See* Order No. 697–A, FERC Stats. & Regs. ¶ 31,268 at n.6. We propose to amend Appendix A to Subpart H of Part 35 to add the market share screen that was inadvertently removed and to make proposed changes to both indicative screens as discussed herein.

[40] The EQR data dictionary defines firm power sales as sales that are non-interruptible for economic reasons and states that contracts with durations of one year or greater are long-term.

[41] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at PP 37–38; April 14, 2004 Order, 107 FERC ¶ 61,018 at P 71 (''We will adopt an uncommitted pivotal supplier analysis that will evaluate the potential of an applicant (including its affiliates) to exercise market power based on the control area market's annual peak demand. We will also adopt an uncommitted market share analysis that will seasonally evaluate the market share of the uncommitted capacity of an applicant and its affiliates.'').

[42] ''Relevant'' capacity refers to seller and affiliated capacity in the study area, including the first tier.

[43] Such a change would be a departure from the characteristics the Commission relied upon in granting market-based rate authority. *See* 18 CFR 35.42(a).

[44] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 37.

[45] *Id.* P 232.

[46] *Id.* n.217.

[47] *Id.* P 231 n.215.

within the metered boundaries of a balancing authority, and the balancing authority maintains load/resource balance within this area.'' [48] Order No. 697 rejected the concept of a ''hub'' as a relevant geographic market, noting that for purposes of evaluating market power, ''trading hub data alone does not provide a foundation for the Commission to analyze transmission limitations and other transfers of energy.'' [49] However, Order No. 697 did not specifically address the default market for a seller located in a balancing authority area that has generation capacity but no load or customers (a generation-only balancing authority area). As discussed below, the Commission is concerned that the default market definition from Order No. 697 does not accurately reflect the market for all sellers, particularly in the Western Electricity Coordinating Council (WECC), which has several generation-only balancing authority areas with generation that is not sited close to load.

49. The issue of what constitutes an appropriate market for an IPP in a generation-only balancing authority area has arisen because there is often no clear nexus between the default market, the generation resources an IPP competes with, and the customers an IPP actually serves.[50] Since the implementation of Order No. 697, we have observed several instances in which the default market may not be appropriately defined for some IPPs in generation-only balancing authority areas.[51] Moreover, the issue of proposing an appropriate geographic market for IPPs in generation-only balancing authority areas that do not serve load in the default market (i.e., their home balancing authority area) is further complicated when the IPP makes sales to a trading hub (e.g., Palo Verde). The following factors illustrate some differences between IPPs and franchised public utilities in terms of identifying the appropriate geographic markets.

50. Franchised public utilities typically have a geographically-defined franchised service territory and an obligation under state law to serve retail customers residing within that service territory.[52] Thus, the home balancing authority area reflects the primary market in which a franchised public utility sells electricity, because this is where its customers are located. In addition, a franchised public utility's generation capacity is usually dedicated primarily to serving load in its franchised service territory even though it may sell at least some wholesale power outside of its service territory. Therefore, the default market (home and first-tier balancing authority areas) is appropriate for franchised public utilities because there is a clear nexus between the physical location of a franchised public utility's generation and the load served by that generation.

51. In contrast, an IPP does not have a franchised service territory, or an obligation to serve retail customers.[53] Moreover, generation-only balancing authority areas do not have any load; therefore, these balancing authority areas do not appear to meet the Commission definition of a default market as they do not, by definition, ''maintain[] load/resource balance with the area.'' [54] IPPs may directly interconnect to transmission providers at energy trading hubs to facilitate sales to one or more markets within the broader region.

b. Proposal

52. In light of the unusual and complex circumstances identified above that are associated with defining the relevant geographic market of an IPP located in a generation-only balancing authority area, and in light of the fact that a generation-only balancing authority area is not a market, we propose that the default relevant geographic market(s) for such a seller would be the balancing authority areas of each transmission provider to which its generation-only balancing authority area is directly interconnected.[55] Thus, if an IPP's generation-only balancing authority area is directly interconnected with one or more balancing authority areas, the IPP would provide indicative screens for each of those balancing authority areas.

53. We further propose that such IPP seller study *all* of its uncommitted generation capacity from the generation-only balancing authority area in the balancing authority area(s) of each transmission provider to which it is directly interconnected, since *all* such uncommitted capacity could potentially be sold in each market that is directly interconnected to the IPP's generation-only balancing authority area, even if the IPP has not sold into that market in the past.

54. To illustrate how this proposal would work, if an IPP is located in a generation-only balancing authority area that is embedded within a transmission provider's balancing authority area, and that balancing authority area is the only balancing authority area that the IPP's generation-only balancing authority area is directly interconnected with, then the IPP will provide indicative screens for that transmission provider's balancing authority area. An IPP in this situation would not need to study the transmission provider's balancing authority first-tier markets, just as would be the case if that generator were similarly located in the transmission provider's balancing authority area. An example of this situation is NaturEner Power Watch, LLC (NaturEner), which has a generation-only balancing authority area that is located within the NorthWestern Energy balancing authority area. Thus, NaturEner would provide indicative screens that examine all of its uncommitted capacity in the NorthWestern Energy balancing authority area. NaturEner would not need to study itself in any other balancing authority areas unless its generation-only balancing authority area is directly interconnected to other balancing authority areas.

55. Similarly, if an IPP is located in a generation-only balancing authority area in a remote area such as the desert

[48] *Id.* P 251.

[49] *Id.* P 275. We note that a number of hubs (e.g., Palo Verde, Four Corners, and Mead, etc.) are located at the intersections of clearly-defined balancing authority areas. Historically, identifying the market for generation located at the hub was not important because vertically-integrated utilities used their own generation to meet their load. As the markets have evolved, many hubs have become trading centers and some IPPs have built generation near hubs. The Commission has defined a trading hub as ''a representative location at which multiple sellers buy and sell power and ownership changes hands, typically with trading of financial and physical products.'' *Id.*

[50] For purposes of market power analyses for market-based rate authority, we propose to define an IPP as a generation resource that has power production as its primary purpose, does not have a native load obligation, is not affiliated with any transmission owner located in the first-tier markets in which the IPP is competing and does not have an affiliate with a franchised service territory. This IPP could also have an OATT waiver on file.

[51] *See, e.g., Sundevil Power Holdings, LLC,* Docket No. ER10–1777–000 (Sept. 15, 2010) (delegated letter order).

[52] *See* 18 CFR 35.36(a)(5). A franchised public utility's obligation to serve is modified, but not entirely eliminated, in states that have implemented ''retail choice.''

[53] Thus, the Commission's policy is to use the balancing authority area(s) (or RTO) where an IPP's generation is physically located as the relevant geographic market(s). Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 232 n.217.

[54] *Id.* P 251; *see also* NERC Glossary of Terms Used in NERC Reliability Standards 10 (2014) (''The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.''), *http://www.nerc.com/files/glossary_of_terms.pdf.*

[55] Consistent with the Commission's proposal above in the section dealing with proposed new filing requirements for sellers in RTOs, the IPP would not need to study itself in any RTO market to which its generation-only balancing authority area is directly interconnected. Instead, the IPP must include a statement that it is relying on Commission-approved market monitoring and mitigation to address any potential horizontal market power concerns.

Southwest, then the Commission proposes that the IPP would have to provide indicative screens for the balancing authority area(s) of the transmission provider(s) to which its generation-only balancing authority area is directly interconnected. We further propose that an IPP assume that *all* of its uncommitted capacity may compete in each balancing authority area to which its generation-only balancing authority area is directly interconnected, since, as noted above, *all* such uncommitted capacity could potentially be sold in each market to which there is a direct interconnection, even if the IPP has not sold into that market in the past. Thus, for example, if it were the case that the generation-only balancing authority areas of the Gila River Power Company LLC and Sundevil generating plants are each directly interconnected with the balancing authority area operated by Arizona Public Service Co. (APS), then each of those IPPs would study themselves in the APS balancing authority area, and each would include all other competing generators from generation-only balancing authority areas directly interconnected with the APS balancing authority area in that study as well. These IPPs in generation-only balancing authority areas would also study themselves in the same manner in any other balancing authority areas to which their generation-only balancing authority area is directly interconnected.[56] Consistent with what is proposed above, an IPP in this situation would not need to study any first-tier markets, just as would be the case if it were a generator located within the transmission provider's home balancing authority area.[57]

56. If an IPP in a generation-only balancing authority area is directly interconnected to a transmission provider at an energy trading hub, we propose that the IPP would provide screens that study itself in the balancing authority area of each transmission provider that is directly interconnected at the trading hub. Thus, the balancing authority areas that are directly interconnected at the hub would each be relevant geographic markets for that IPP, and the IPP would provide screens that study the IPP in each of those transmission providers' balancing authority areas.[58] Consistent with what is proposed above, we propose that the IPP should provide indicative screens that assume that *all* of its uncommitted capacity may compete in each of the balancing authority areas that are directly interconnected at that trading hub, since *all* such uncommitted capacity could potentially be sold in each market to which there is a direct interconnection, even if the IPP has not sold into that market in the past.[59] Thus, for example, if an IPP in a generation-only balancing authority area in the Arizona desert is directly interconnected to a transmission provider at the Palo Verde trading hub at the Palo Verde and Hassayampa switchyards,[60] then it would provide screens that study all of its uncommitted capacity in each balancing authority area that is directly interconnected at the switchyard. Also, consistent with what is proposed above, an IPP in this situation would not need to provide screens that study itself in any markets that are first tier to the various balancing authority areas that are directly interconnected at the switchyard.

57. We seek comment on these proposals.

4. Reporting Format for the Indicative Screens

a. Current Policy

58. When submitting a horizontal market power analysis, sellers are required to use the standard screen format provided in Appendix A to Subpart H of Part 35 for submitting their indicative screens. Although sellers submit their indicative screens based on the formats provided in Appendix A to Subpart H of Part 35 and in Commission Order Nos. 697 [61] and 697–A,[62] they currently perform their own mathematical calculations. The Commission does not currently provide pre-programmed spreadsheets that allow for automated mathematical calculations for sellers' indicative screens. When preparing their screens, certain sellers also perform SIL studies, which produce data (e.g., SIL values) applicable to the indicative screens.

59. In *Puget,*[63] the Commission adopted a standardized format for reporting SIL study results in order to help ensure greater efficiency. The Commission directed sellers to refer to the guidance, directions, and reporting format provided in Appendix B of *Puget* when preparing and submitting SIL studies.[64] Appendix B of *Puget* discusses various submittals, including ''Submittal 1,'' which is a spreadsheet that calculates the SIL values to be used in the indicative screens. Submittal 1 is a summary spreadsheet of the SIL components used to calculate the SIL values and is currently posted on the Commission's Web site. The last line of Submittal 1 (Row 10) contains the SIL values that sellers should use in preparing their screens.[65] Currently, the screen reporting format in Appendix A of Subpart H, which is discussed in Order Nos. 697 and 697–A, does not have a row for SIL values even though the Uncommitted Capacity Import values in the indicative screens are constrained by the SIL value from Row 10 of Submittal 1, i.e., the sum of the affiliated and non-affiliated Uncommitted Capacity Import values cannot exceed the SIL value.[66]

60. Appendix B of *Puget* also discusses ''Submittal 2,'' which is a spreadsheet that identifies long-term firm transmission reservations used to import power from seller and affiliate generating resources in the first-tier area to serve native load in the study area. The calculations performed in Submittal 2 provide detailed data summed to produce the total value of long-term firm transmission reservations, which are included in Row 5 of Submittal 1.

61. The Commission provided additional direction on the completion of the indicative screens in *Vantage Wind Energy, LLC.*[67] In particular, the Commission provided direction on how to account for both remote generation resources and long-term firm power purchases from generation resources located outside a seller's home balancing authority area when

[56] However, the transmission provider, in all cases, would consider the IPP generation capacity as first-tier generation when conducting its SIL studies and indicative screens.

[57] *See* Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 232 n.217.

[58] When we state that the transmission providers' balancing authority areas are directly interconnected at the hub we are assuming that all such balancing authority areas are directly interconnected with each other.

[59] When providing screens for the directly interconnected balancing authority areas, the IPP would also include the uncommitted capacity of any other generation-only balancing authority area also interconnected to the same transmission providers at that hub. However, the transmission providers, in all cases, would consider the IPP generation capacity as first-tier generation when conducting their SIL studies and indicative screens.

[60] A generator interconnected to a transmission provider at a location where the transmission provider is directly interconnected to other transmission providers would also be directly interconnected to those other transmission providers.

[61] *See* Order No. 697, FERC Stats. & Regs. ¶ 31,252 at PP 305–306.

[62] *See* Order No. 697–A, FERC Stats. & Regs. ¶ 31,268 at P 17 n.6, Appendix A.

[63] *Puget,* 135 FERC ¶ 61,254 at Appendix B.

[64] *Id.* P 20.

[65] *Id.* at Appendix B.

[66] *See* Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 361 (explaining that a SIL study determines ''how much competitive supply from remote resources can serve load in the study area.'').

[67] *Vantage Wind Energy, LLC,* 139 FERC ¶ 61,063, at P 21 (2012) (*Vantage Wind*).

performing the indicative screens.[68] Currently, the indicative screen reporting formats in Appendix A of Subpart H and Order Nos. 697 and 697–A do not have separate rows for the value of installed capacity of remote generation resources or the capacity of resources that are external to the study area that support long-term firm power purchase agreements that serve load in the study area; both values are components of the SIL value used in the screens.

b. Proposal

62. We propose to amend the indicative screen reporting format in Appendix A of Subpart H. We propose that Appendix A include both the pivotal supplier and market share screen reporting formats with new rows for SIL values, Long-Term Firm Purchases (from outside the study area), and Remote Capacity (from outside the study area). Including a row in the indicative screens for SIL value will help reinforce the relationship between the values for affiliated and non-affiliated capacity imports and the SIL value. For purposes of clarification, we also propose to modify the descriptive text of the rows in the indicative screens for Installed Capacity, Long-Term Firm Purchases, Long-Term Firm Sales, and Uncommitted Capacity Imports.[69] As discussed below, the new rows and their descriptions will clarify that the resources are either inside or outside the study area for Installed Capacity and Long-Term Firm Purchases. Furthermore, the description for Uncommitted Capacity Imports will now be consistent across both indicative screens. An example of the proposed new indicative screen reporting formats for Appendix A to Subpart H is provided in Appendix A of this NOPR.

63. Additionally, we propose to revise the regulations at 18 CFR 35.37(c)(4) to require sellers to file the indicative screens in a workable electronic spreadsheet format.[70] The proposed new language is as follows: When submitting (*proposing to delete*) [a horizontal market power analysis]*the indicative screens,* a Seller must use the form*at* provided in Appendix A of this subpart and *file the indicative screens in an electronic spreadsheet format. A Seller must* include all supporting materials referenced in the *indicative screens (proposing to delete*) [form].

We propose to post on the Commission's Web site a pre-programmed spreadsheet as an example that sellers may use to submit their indicative screens.[71] The example spreadsheet contains pre-programmed cells that allow for summations and data comparisons, as well as cells that restrict entries to negative or positive values where appropriate. We believe that these proposed changes to the indicative screens, as reflected in Appendix A to this NOPR, will aid sellers when preparing screens and minimize the need for follow up inquiries from staff and amended filings.

64. We also propose to add a paragraph to the end of § 35.37(c), making it paragraph (c)(5), to codify the requirement in *Puget* that sellers submitting SIL studies adhere to the direction and required format for Submittals 1 and 2 found on the Commission's Web site[72] and submit their information, as instructed, in workable electronic spreadsheets. The proposed new language is as follows: *Sellers submitting simultaneous transmission import limit studies must file Submittal 1, and, if applicable, Submittal 2, in the electronic spreadsheet format provided on the Commission's Web site.*

Revising the regulations to reflect this requirement will help ensure that sellers are aware of the requirement to include Submittals 1 and 2 in workable electronic spreadsheets as well.[73]

65. We seek comment on these proposals.

5. Competing Imports

a. Current Policy

66. The Commission permits sellers to make simplifying assumptions, where appropriate, and to submit streamlined horizontal market power analyses.[74] In Order No. 697, the Commission stated that ''a seller, where appropriate, can make simplifying assumptions, such as performing the indicative screens assuming no import capacity or treating the host balancing authority area utility as the only other competitor.''[75]

b. Proposal

67. We clarify that the phrase ''assuming no import capacity'' means that a seller may assume ''no *competing* import capacity'' from the first-tier markets (i.e., adjacent balancing authority areas or markets). This clarification is consistent with the April 14, 2004 Order[76] and other Commission orders.[77] We further clarify that the seller must still include any uncommitted capacity that it and its affiliates can import into the study area. We believe that this clarification will aid sellers when preparing screens and minimize the need for follow up

[68] *Id.* (''[L]oad serving entities should add their share of remote generation to Installed Capacity (Line A of the market share screen and the pivotal market share screen) and the amount of any long-term firm purchases in 'Long-term Firm Purchases' (Line B of the market share screen and the pivotal supplier screen) of the indicative screens, when load-serving entities have long-term firm transmission rights associated with those resources.'').

[69] We propose to change the phrase ''Imported Power'' in Rows D and H of the pivotal supplier screen to ''Uncommitted Capacity Imports.'' We also propose to make the same change to Row E of the Market Share Screen. Thus, all four rows in the indicative screens will have the same text for this field, which represents affiliate and non-affiliate uncommitted capacity able to be imported from the first tier.

[70] ''Workable electronic spreadsheet'' refers to a machine readable file with intact, working formulas as opposed to a scanned document such as an Adobe PDF file.

[71] If a seller chooses to create its own workable electronic spreadsheet, the file it submits must have the same format as the sample spreadsheet on the Commission Web site. Specifically, it must have one worksheet for each of the indicative screens and each screen must have the same exact rows, columns, and descriptive text as the sample worksheets. Cells requiring negative values must be pre-programmed to only allow negative values. Likewise, cells with calculated values must contain a working formula that calculates the value for that cell. Finally, the file must be submitted in one of the spreadsheet file formats accepted by the Commission for electronic filing. *See* FERC, Acceptable File Formats (Jan. 2012), *available at http://www.ferc.gov/docs-filing/elibrary/accept-file-formats.asp.*

[72] The sample spreadsheets for Submittals 1 and 2 are found at the Commission's Web site at *http://www.ferc.gov/industries/electric/gen-info/mbr/authorization.asp* under ''Quick Links.''

[73] Here, as with the indicative screens, if a seller chooses to create its own workable electronic spreadsheet, the file it submits must have the same format as the sample spreadsheet on the Commission Web site. Specifically, it must have the same exact rows, columns, and descriptive text as the sample spreadsheet. Likewise, cells with calculated values must contain working formulas that calculate the value for that cell. Finally, the file must be submitted in one of the spreadsheet file formats accepted by the Commission for electronic filing. *See* FERC, Acceptable File Formats (January 2012), *available at http://www.ferc.gov/docs-filing/elibrary/accept-file-formats.asp.*

[74] *See* Order No. 697, FERC Stats. & Regs. ¶ 31,252 at PP 308, 321; April 14, 2004 Order, 107 FERC ¶ 61,018 at P 38.

[75] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 321.

[76] April 14, 2004 Order, 107 FERC ¶ 61,018 at P 38 (''Where appropriate, the screens allow the applicant to submit streamlined applications or to forego the generation market power analysis entirely and, in the alternative, go directly to mitigation. For example, if an applicant would pass the screens without considering *competing* supplies from adjacent control areas, the applicant need not include such imports in its studies.'' (emphasis added)).

[77] *See, e.g., Acadia Power Partners, LLC,* 107 FERC ¶ 61,168, at P 12 (2004) (''We remind applicants that they may provide streamlined applications, where appropriate, to show that they pass both screens. For example, if an applicant would pass both screens without considering *competing* supplies imported from adjacent control areas, the applicant need not include such imports.'' (emphasis added) (footnote omitted)).

inquiries from staff and amended filings.

6. Capacity Ratings

a. Current Policy

68. The Commission allows sellers submitting indicative screens to rate their generation facilities using either nameplate or seasonal capacity ratings.[78] With regard to sellers with energy-limited resources, such as hydroelectric and wind generation facilities, in lieu of using nameplate or seasonal capacity ratings in their submissions, the Commission stated in Order No. 697 that it would allow such sellers to provide an analysis based on historical capacity factors reflecting the use of a five-year average capacity factor, including a sensitivity test using the lowest and highest capacity factors for the previous five years.[79] Since the issuance of Order No. 697, the Commission has recognized that sellers with newly-built energy-limited generation facilities may not have five years of historical data for use in their analyses. To address this situation, the Commission has allowed the use of the five most recent years of regional average capacity factors from the EIA to determine capacity factors for those resources.[80]

b. Proposal

69. We recognize that there are energy-limited generation resources, such as solar photovoltaic and solar thermal facilities (collectively, solar technologies), which were not identified in Order No. 697. We propose to identify solar technologies as energy-limited generation resources and to allow such sellers to use either nameplate capacity or five-year historical average capacity ratings to determine the capacity rating for their solar technology generation resources, and, as noted above, sellers may use EIA regional average capacity factors for the previous five years to determine capacity for those resources. Similar to other energy-limited generation resources, sellers using the five-year historical average must include sensitivity tests using the lowest and highest capacity factors for the previous five years. We propose that sellers with energy-limited generation facilities (including those using solar technology) that do not have five years of historical data may use the EIA-derived, regional capacity factor estimates appropriate to their specific technology as defined in the EIA publication *Annual Energy Outlook*.[81] We also propose to require that sellers without five years of historical data use either nameplate capacity or the EIA-derived, regional capacity factor estimates, but not seasonal ratings.[82] For sellers using EIA-derived estimates, we propose to require that they submit their calculation of the regional capacity factor as well as copies of the appropriate tables of regional generation capacity ratings from EIA's *Annual Energy Outlook* in their filing. In addition, the Commission seeks industry input in identifying additional technologies that are energy-limited generation resources, and what capacity factors should be used to rate them.

70. While we are proposing this treatment for solar capacity, we acknowledge that photovoltaic solar facilities will effectively function with zero capacity during nighttime hours or during heavy overcast conditions, as the sun does not provide much, if any, solar energy from photovoltaic solar facilities during such conditions. Thus, we are seeking comment on whether it may make more sense to assign different capacity factors to solar generation as compared to other generation based on these operating characteristics. In particular, we seek comment on whether we should allow such sellers to use either nameplate capacity or five-year historical average capacity ratings during peak hours to determine the capacity rating for their solar technology generation resources, and, as noted above, sellers may use EIA regional average capacity factors over peak hours for the previous five years to determine capacity for those resources. *In other words, we seek comment on whether using peak hours will provide a better measure of capacity for photovoltaic solar, as compared to all hours, which would necessarily include hours in which we can predict that output will be zero.*

71. Finally, consistent with Order No. 697, we propose to clarify that, within each filing, a seller must use the same capacity rating methodology for similar generation assets.[83] Specifically, if a seller chooses in a particular filing to use seasonal ratings for one of its thermal units, it must use seasonal ratings for all of its thermal units in that filing. Likewise, if the seller chooses to use an alternative rating methodology, such as the five-year average for any energy-limited generation resource, it must use the five-year average for all energy-limited generation resources in that filing, for which five years of historical data is available; otherwise it must use the EIA-derived capacity factors for those resources for which the seller does not have five years of data. The seller must specify in the filing's transmittal letter or accompanying testimony, and in the generation asset appendix, which rating methodologies it is using. The seller must use the specified rating methodologies consistently throughout its entire filing, including in its transmittal letter, asset appendix, and indicative screens. This proposal does not preclude the seller from using a different capacity rating methodology for each type of generation facility (thermal or energy-limited) in subsequent filings (e.g., in its initial filing a seller may use nameplate ratings for its thermal units, then in its next filing choose to use seasonal ratings for its thermal units). We believe that when a seller consistently uses the same rating methodology within a filing, it will improve the accuracy of the horizontal market power analysis by linking the capacity values in the transmittal letter, accompanying testimony, generation asset appendix, and the indicative screens.

72. We seek comment on these proposals.

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[78] *See* Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 343 (''We will adopt the NOPR proposal that allows sellers to use seasonal capacity. We clarify that each seller must be consistent in its choice and thus must choose either seasonal or nameplate capacity and use it consistently throughout the analysis. In addition, a seller using seasonal capacity must identify in its submittal from what source the data was obtained.''). The Commission adopted the EIA definition of seasonal capacity as reported on Form EIA–860, Schedule 3, Part B, Line 2, which provides that seasonal capacity is the '''net summer or winter capacity''' and EIA instructions that '''net capacity should reflect a reduction in capacity due to electricity use for station service or auxiliaries.''' *Id.* (footnotes omitted).

[79] *Id.* P 344.

[80] *See Golden Spread Electric Coop., Inc.,* 138 FERC ¶ 61,208, at P 16 (2012) (*Golden Spread*) (finding that a five-year average wind capacity factor derived from EIA data represents an appropriate analysis).

[81] *See* EIA, Annual Energy Outlook (May 2014), *available at http://www.eia.gov/forecasts/aeo/source_renewable.cfm.* In Table 58 through Table 58.9 ''Renewable Energy Generation by Fuel—(by Area),'' EIA provides data for the total generating capacity, and actual (or estimated) electricity generated by renewable type for 22 ''electricity market module regions'' covering the lower 48 states. After converting the inputs into matching units, sellers can divide actual (or estimated) electricity generated by installed capacity to find the capacity factor.

[82] Sellers should use either nameplate, a five-year average of historical data, or EIA-derived five-year average regional capacity factors instead of seasonal capacity factors for energy-limited resources. The Commission found that a five-year average wind capacity factor derived from EIA regional data was an appropriate proxy for wind generators that do not have five years of historical data. *See Golden Spread,* 138 FERC ¶ 61,208 at P 16.

[83] *See* Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 343.

7. Reporting of Long-Term Firm Purchases

a. Current Policy

73. In Order No. 697, the Commission stated that a seller's uncommitted capacity, as calculated in the indicative screens, is determined by adding the total nameplate or seasonal capacity of generation owned or controlled through contract and long-term firm capacity purchases, less operating reserves, native load commitments, and long-term firm sales.[84] The Commission specified that capacity associated with contracts that confer operational control of a given facility to an entity other than the owner must be assigned to the entity exercising control over that facility, rather than to the entity that is the legal owner of the facility.[85] Order No. 697 stated that if a market-based rate applicant has control over certain capacity, such that that applicant can affect the ability of the capacity to reach the market, then that capacity should be attributed to that applicant when performing the indicative screens.[86] As a result, in their initial and triennial market-based rate filings, market-based rate applicants[87] have been required to report long-term firm purchases in Row B of the indicative screens (Long-Term Firm Purchases) only if the purchase granted them control of the capacity.[88] Similarly, for purposes of reporting a change in status, market-based rate applicants have been required to report long-term firm capacity purchases when assessing their cumulative generation capacity only if such purchases confer control of such capacity to the applicant purchaser.[89]

74. This requirement also applies to long-term firm *energy* purchases to the extent that the long-term firm energy purchase would allow the purchaser to control generation capacity.[90] In this regard, in Order No. 697–B, the Commission stated that if a contract for a fixed quantity of delivered energy does not confer control, it need not be reported.[91] The Commission stated its belief at that time that a long-term firm energy purchase by itself gives the purchaser only a right to receive energy and thus no rights that would allow the purchaser to control generation capacity, and that a determination of whether a long-term firm energy purchase confers control over generation capacity must be based on a review of the totality of the circumstances on a fact-specific basis.[92] Many applicants under the market-based rate program, therefore, do not report some or all of their long-term firm power purchases (including long-term firm energy purchases) in their indicative screens if they believe these purchases do not grant them control of the capacity.

75. As explained below, we have determined, after two complete rounds of regional reviews, that the limited reporting of long-term firm purchases may create errors or misleading results in the indicative screens submitted by some sellers. These errors include incorrectly-sized markets and negative market shares for franchised public utilities and inconsistencies between the SIL values reported in the screens and the SIL values calculated for the relevant market or balancing authority area. Specifically, on numerous occasions the Commission has encountered situations where neither the seller nor the purchaser under a long-term firm power sale is being attributed with the generation capacity that is used to make that sale. This is because the seller, consistent with Commission policy, has deducted the capacity committed under the long-term firm power sale[93] for purposes of calculating that seller's uncommitted capacity, while the purchaser has used our policies (and underlying assumptions) outlined above to assume that it is also not responsible for this capacity and therefore has not included this capacity as part of the purchaser's uncommitted capacity. The combination of these actions by sellers and purchasers results in capacity under long-term firm power purchase agreements many times ''disappearing'' from the market, with neither counterparty reflecting the capacity in their screens.

76. One result of this practice is that it leads to the anomalous result in the indicative screens of some franchised public utility sellers appearing to be net short; that is, appearing to lack sufficient generation resources (both owned and purchased) to serve their peak load. In reality, franchised public utilities are required by state regulators to have sufficient generation resources (owned capacity and firm purchases) to serve their projected peak load and an additional ''planning reserve margin'' on top of that.[94] Although it is unrealistic for franchised public utilities to rely extensively on spot market purchases to serve statutory load obligations, that is what is implied in some of the indicative screens that have been submitted by franchised public utilities that do not include long-term firm purchases in their indicative screens.

77. Moreover, our experience with the horizontal market power analyses submitted subsequent to the implementation of Order No. 697 has shown us that in the typical situation, the capacity associated with a long-term firm power purchase agreement should be attributed to the purchaser, not the seller. This is because long-term firm power purchase agreements, including long-term firm energy agreements, provide the purchaser with energy that only can be interrupted for limited and specified reasons (e.g., force majeure). A firm energy sale cannot, for example, be interrupted by the seller for economic reasons. Thus, a seller must have capacity supporting a firm energy sale and this capacity is now effectively serving the purchaser, much like the purchaser's owned generation capacity.

78. As an example of this, the Commission recently addressed problems associated with the misreporting of long-term firm purchases in *Vantage Wind*.[95] In *Vantage Wind,* a non-affiliated seller prepared a horizontal market power study for a balancing authority area based on the data used by the transmission owner. However, the

[84] *Id.* P 38.

[85] *Id.* P 157.

[86] *Id.* P 174. The Commission found that determination of control is based on a review of the totality of circumstances on a fact-specific basis. *Id.*

[87] Although we generally use the term ''market-based rate sellers'' elsewhere in this NOPR, in this section we refer to such sellers as ''market-based rate applicants'' to avoid confusion when discussing sellers who are purchasers under long-term firm power purchase agreements.

[88] Reflecting this capacity in Row B has the effect of attributing the capacity to the market-based rate applicant.

[89] Order No. 697–B, FERC Stats. & Regs. ¶ 31,285 at PP 99–101.

[90] *Id.*

[91] *Id.* P 99.

[92] *Id.* P 101. In *Integrys Energy Group, Inc.,* 123 FERC ¶ 61,034 (2008), the Commission found that the sale of a ''Firm (LD)'' product, as defined in the EEI Master Power Purchase & Sale Agreement, by itself gives the purchaser only a right to receive energy and thus no rights that would allow the purchaser to control generation capacity. In reaching this determination, the Commission relied on the fact that the purchaser under a Firm (LD) product cannot force the seller to back down the output of any generator and the fact that if the purchaser refused to receive delivery, that refusal does not keep the power from entering the market because the seller has the right to resell the Firm (LD) product, as well as to receive damages from the purchaser.

[93] The EQR Data Dictionary defines a firm sale as ''a sale, service or product that is not interruptible for economic reasons.'' *See Filing Requirements for El. Utility S.A., Order Updating Electric Quarterly Report Data Dictionary,* 146 FERC ¶ 61,169, Attachment (2014) (''EQR Data Dictionary Transaction Data'' table, field number 59).

[94] *See, e.g.,* Staff of the California Public Utilities Commission with the assistance of California Energy Commission Staff, *2011 Resource Adequacy Report* (Feb. 5, 2013), *available at http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/.*

[95] *Vantage Wind,* 139 FERC ¶ 61,063 at P 21.

transmission owner failed to properly account for its long-term firm purchases in its indicative screens for its home balancing authority area. The transmission owner was entitled to receive the output associated with several long-term firm power purchases, but did not report the capacity supplying these long-term firm purchases. As a result, the non-affiliated seller appeared (incorrectly) to fail the screens because the transmission owner's capacity effectively was underreported. In *Vantage Wind,* the Commission corrected for this underreporting of capacity by directing the load-serving entity purchasers to report all long-term firm purchases in Row B of the indicative screens (Long-Term Firm Purchases) if the purchase had long-term firm transmission rights associated with those resources.[96] This direction in the *Vantage Wind* order resulted in the purchasers having to include the generation capacity associated with such long-term firm purchases as part of the purchasers' capacity. Otherwise, this generation capacity would have ''disappeared'' from being evaluated under the market-based rate program. We note that in directing this outcome, the Commission did not consider the issue of who had operational control of the capacity supplying the long-term firm purchases; rather, the Commission assigned the capacity to the purchasers under the long-term firm power purchase agreement.

b. Proposal

79. For the reasons stated above, we propose to modify the policy with respect to the reporting of long-term firm purchases in the indicative screens. Specifically, we propose to require applicants under the market-based rate program to report all of their long-term firm purchases [97] of capacity and/or energy in their indicative screens and asset appendices, where the purchaser has an associated long-term firm transmission reservation, regardless of whether the seller has operational control over the generation capacity supplying the purchased power. If the long-term firm purchase involves the sale of energy, then the purchaser must convert the amount of energy to which it is entitled into an amount of generation capacity for purposes of its indicative screens and asset appendices, i.e., include the amount of the capacity as long-term firm purchases in Rows B (Long-Term Firm Purchases (from inside the study area)) or B1 (Long-Term Firm Purchases (from outside the study area)) of the proposed revised indicative screens and include it in its asset appendix. The seller under that power purchase agreement must do the same the next time it submits a market-based rate triennial or change of status filing with the Commission, i.e., convert the energy into capacity and include the amount of capacity as a long-term firm sale in Row C (Long-Term Firm Sales).[98] When making these filings, we propose that both the purchaser and the seller must show how they made the energy-to-capacity conversion. Although this attribution of capacity is the default approach that we propose as a general policy, applicants or intervenors are free to raise fact-specific circumstances that they believe may support a different attribution of capacity.

80. The intent of our proposed reform is to have an entity with market-based rate authority report all long-term firm purchases that it makes where the selling entity has a legal obligation to provide the purchaser with an energy supply that cannot be interrupted for economic reasons or at the seller's discretion. If the purchaser has contractual rights to receive the output of a long-term firm energy purchase, we propose that the amount of the capacity supplying that purchase must be reported in the purchaser's screens. We also propose to require that all such long-term firm purchases should be reported in Rows B (Long-Term Firm Purchases (from inside the study area)) or B1 (Long-Term Firm Purchases (from outside the study area)) of the proposed revised indicative screens, depending on whether the generation resource(s) supplying the sale are located inside or outside the seller's balancing authority area, as explained earlier in this proposed rule.

81. The proposal to require applicants under the market-based rate program to report all of their long-term firm purchases of capacity and/or energy in their indicative screens and asset appendices is supported based on the following considerations. First, it will size the market correctly and therefore improve the accuracy of the indicative screens, especially for franchised public utilities, whose indicative screens are used by the non-transmission owning sellers to prepare their own indicative screens. Currently, sellers often do not report some or all of their long-term firm purchases because they do not control these resources. Including all long-term firm purchases in the indicative screens will properly size the market and eliminate the unrealistic results (e.g., negative market shares) caused by the under-reporting of generation noted above.

82. Second, this proposed change will establish consistent treatment of long-term firm sales and long-term firm purchases in the indicative screens. Market-based rate applicants typically deduct long-term firm sales without making a determination as to whether those sales confer operational control to the purchaser. The Commission, in Order No. 697, did not require that sellers make such a determination before deducting the capacity supporting long-term firm sales: ''Uncommitted capacity is determined by adding the total nameplate or seasonal capacity of generation owned or controlled through contract and firm purchases, less operating reserves, native load commitments and long-term firm sales.'' [99] The Commission clarified that ''[s]ellers may deduct generation associated with their long-term firm requirements sales, unless the Commission disallows such deductions based on extraordinary circumstances.'' [100]

83. It is only on the ''buy'' side of long-term firm purchases that the Commission has considered the issue of control in reporting capacity in the screens.[101] The result is that some generation capacity sold under long-

[96] *Id.*

[97] The Commission in *Vantage Wind* directed the purchasers to report all long-term firm purchases if the purchase had long-term firm transmission rights associated with those resources. *Id.* We assume for purposes of our proposal here that all long-term firm purchases necessarily have long-term firm transmission rights associated with them. If that is not the case, as noted above, applicants or intervenors are free to raise fact-specific circumstances that they believe may support a different attribution of capacity.

[98] Our understanding is that many power purchase agreements for firm energy specify an associated capacity commitment from the seller. In cases where capacity commitments are not specified in the power purchase agreement, we propose that applicants use the following formula to convert energy to capacity (on a one-year basis): [energy (MWh)/8,760]/capacity factor = capacity (MW).

Where energy (MWh) is the total amount of energy purchased under the power purchase agreement over the calendar year; 8,760 is the total hours of a calendar year (use 8,784 in a leap year); capacity factor is actual capacity factor achieved by the unit(s) supplying the energy during the calendar year and is a measure of a generating unit's actual output over a specified period of time compared to its potential or maximum output over that same period. For example, if 700,000 MWh is the amount of firm energy purchased under a power purchase agreement during a calendar year, and the capacity factor of the generator supplying the energy is 0.8 or 80 percent, then the 700,000 MWh of energy would be converted into approximate 100 MW of capacity. That is: (700,000 MWh/8,760)/0.8 = 100 MW.

[99] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 38 (footnotes omitted).

[100] *Id.* n.18.

[101] Order No. 697–B, FERC Stats. & Regs. ¶ 31,285 at PP 99, 100.

term power purchase agreements ''disappears'' from the market because neither the seller nor the purchaser includes the capacity as part of its uncommitted capacity (i.e., the seller subtracts the amount sold under the long-term power purchase agreement from its capacity for purposes of its screens, but sometimes the purchaser does not add the corresponding amount to its capacity for purposes of its screens). It is inevitable that some generation capacity will be excluded from the indicative screens, with resulting errors in market shares and overall market size, when differing standards are applied to long-term firm purchases and long-term firm sales with respect to the allocation of such capacity. This proposal will make those standards consistent, reducing such errors.

84. Third, requiring the reporting of all long-term firm power purchases also will ensure consistent treatment of owned or installed capacity and long-term firm purchases in the indicative screens. The Commission's horizontal market power analysis implicitly assumes that applicants control all of their owned or installed capacity listed in their indicative screens but this is not necessarily the case.[102] For example, in situations where an applicant is a minority owner of a jointly-owned generating unit, it is quite possible that the applicant will not have operational control (i.e., commitment and dispatch authority) over the unit.[103] However, applicants typically include all of their owned or controlled generation capacity in the indicative screens regardless of whether they actually control the commitment and dispatch of this capacity. Accordingly, we propose that an applicant with long-term firm purchases treat such contracted-for capacity in a similar manner to an applicant that owns capacity; that is, such purchases should be included in the applicant's portfolio of generation for the indicative screens.

85. Finally, for those applicants incorrectly reporting long-term firm power purchases in the wrong row of the indicative screens, uniform reporting of these purchases will also help to ensure consistency between the SIL values reported in the screens and the Commission's accepted SIL values for the relevant market or balancing authority area. As the Commission noted in *Vantage Wind,*[104] improperly classifying long-term firm purchases (or imports of remotely-owned installed capacity) as Imported Power in the existing screens (Row D of the pivotal supplier screen and Row E of the market share screen) may lead to an overstatement of the market's SIL values. This is because the sum of the values in the existing pivotal supplier screen for Seller and Affiliate Imported Power shown in Row D and Non-Affiliate Imported Power shown in Row H should be less than or equal to the Commission-accepted SIL values. All Commission-accepted SIL values account for (i.e., subtract) long-term transmission reservations into the study area, so that they reflect the transmission capability available to competing sellers after accounting for the capability that the local utility has reserved for its own use to import power from remote resources. Thus, classifying long-term firm purchases as Imported Power effectively ''double counts'' import capability in the screens because it adds back the import capability associated with long-term firm purchases and assumes that this capability is available to potential competitors. This problem does not arise if long-term firm purchases (and imports of remotely-owned installed capacity) are properly classified in the indicative screens as Long-Term Firm Purchases (Rows B1 and F1 in the proposed screen format for the pivotal screen) and Remote Capacity (Rows A1 and E1 in the proposed screen format for the pivotal screen), respectively. This proposal is intended to help clarify how to classify imports of firm power and remotely-owned capacity. These proposed changes to the pivotal supplier screen format are also being proposed for the market-share screen.

86. We seek comment on this proposal.

B. Vertical Market Power—Land Acquisition Reporting

1. Current Policy

87. All market-based rate sellers are currently required, pursuant to § 35.42(d) of the Commission's regulations and Order Nos. 697–C and 697–D, to file notices of change in status on a quarterly basis when they acquire sites for new generation capacity development.[105] To date, not a single protest has been filed in response to these copious filings and the Commission has not uncovered any issues indicating that a particular seller has erected a barrier to entry as a result of its land acquisition. On a number of occasions over the years, market-based rate sellers have expressed frustration with this reporting requirement and have described it as burdensome.

88. In Order No. 697, the Commission stated it would consider a seller's ability to erect other barriers to entry as part of the vertical market power analysis. Thus, the regulations require that a seller provide a description of its ownership or control of, or affiliation with an entity that owns or controls, intrastate natural gas transportation, intrastate natural gas storage or distribution facilities, sites for generation capacity development, and physical coal supply sources and ownership or control over who may access transportation of coal supplies.[106] The Commission noted that, to date, it had not found such ownership or control to be a potential barrier to entry warranting further analysis, but that it did not have sufficient evidence to remove these inputs from the analysis entirely. Thus, it rebuttably presumed that ownership or control of or affiliation with an entity that owns or controls such facilities does not allow a seller to raise entry barriers, but would allow intervenors to demonstrate otherwise.[107] In Order No. 697–C, the Commission noted that ''[o]ne of the purposes of the change of status reporting requirement is to provide interested parties the opportunity to intervene and comment if they believe the seller's acquisition of sites for new generation capacity

[102] In Order No. 697, the Commission noted that its historical approach has been that the owner of a facility is presumed to have control of the facility unless such control has been transferred to another party by virtue of a contractual agreement. The Commission stated that it would continue its practice of assigning control to the owner absent a contractual agreement transferring such control. Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 183.

[103] Another example is when a generator confers operational control to a third party through a long-term tolling agreement. *See, e.g., Shell Energy North America (US),* L.P., 135 FERC ¶ 61,090, at P 3 (2011).

[104] *Vantage Wind,* 139 FERC ¶ 61,063 at P 16 (''In its updated market power analysis, Puget accounted for both its remote generation from its Colstrip plant located in Montana and its firm power purchase agreements from Bonneville as Imported Power (Line D of the market share screen and the pivotal supplier screen) rather than as Installed Capacity (Line A of the market share screen and the pivotal supplier screen) or a Long-term Firm Purchase (Line B of the market share screen and the pivotal supplier screen), respectively. Consequently, the total SIL shown in Puget's screens exceeded the net SIL value for the Puget balancing authority area as accepted by the Commission in [*Puget Sound Energy, Inc.,* 135 FERC ¶ 61,254 (2011)]. When Vantage Wind applied the Commission-approved SIL values to its analysis without making any other adjustments to Puget's screens, Vantage Wind appeared to fail the screens because Puget's capacity was underreported.'').

[105] Order No. 697–C, FERC Stats. & Regs. ¶ 31,291 at PP 18–19; Order No. 697–D FERC Stats. & Regs. ¶ 31,305 at PP 21–23.

[106] 18 CFR 35.37(e).

[107] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 446.

development creates a barrier to entry.'' [108]

2. Proposal

89. We propose to relieve market-based rate sellers of their obligation to file quarterly land acquisition reports and of the obligation to provide information on sites for generation capacity development in market-based rate applications and triennial updated market power analyses because the burden of such reporting outweighs the benefits.[109]

90. In the more than six years since issuance of Order No. 697, intervenors have not challenged whether sites for new generation capacity development created a barrier to entry. For this reason, we propose to eliminate the requirement to provide such information. We note that, if there is a concern that a particular seller's sites for generation capacity development may be creating a barrier to entry, the Commission can request additional information from the seller at any time.[110]

91. Thus, we propose to revise the regulations at 18 CFR 35.42 to remove paragraph (d). This proposed revision removes the requirement that sellers report the acquisition of control of a site or sites for new generation capacity development for which site control has been demonstrated. Likewise, we propose to revise the regulations at 18 CFR 35.42 to remove paragraph (e), which pertains to the definition of site control for purposes of paragraph (d). We also propose to revise the regulations at 18 CFR 35.37 to remove paragraph (e)(2), which requires sellers to provide information regarding sites for generation capacity development to demonstrate a lack of vertical market power. Therefore, under this proposal, § 35.42(d)–(e) and § 35.37(e)(2) would be removed entirely. In addition, we propose to revise 18 CFR 35.42 at paragraph (b) to remove the reference to the reporting of acquisition of control of a site or sites for new generation capacity development. Specifically, under this proposal, § 35.42(b) would read as follows: Any change in status subject to paragraph (a) of this section, (*proposing to delete)* [other than a change in status submitted to report the acquisition of control of a site or sites for new generation capacity development], must be filed no later than 30 days after the change in status occurs. Power sales contracts with future delivery are reportable 30 days after the physical delivery has begun. Failure to timely file a change in status report constitutes a tariff violation.

92. We seek comment on these proposals.

C. Notices of Change in Status

93. Section 35.42(a) of the Commission's regulations requires sellers to report any change in status that would reflect a departure from the characteristics the Commission relied upon in granting market-based rate authority.[111] A change in status filing is required when, among other things, either of two conditions are met:

(1) Ownership or control of generation capacity results in net increases of 100 MW or more; [[112]] or

(2) affiliation with any entity not disclosed in the application for market-based rate authority that (a) owns or controls generation facilities or inputs to electric power production, (b) owns, operates or controls transmission facilities, or (c) has a franchised service area. [[113]]

1. Geographic Focus

a. Current Policy

94. In Order No. 697–A, the Commission clarified that sellers must report a change in status when they acquire 100 MW or more in the ''geographic market that was the subject of the horizontal market power analysis on which the Commission relied in granting the seller market-based rate authority.'' [114]

95. Order No. 697–A also provided an example of when a seller should not file a notice of change in status: ''if a seller has a net increase of 50 MW in the geographic market on which the Commission relied in granting the seller market-based rate authority and a 50 MW increase in a different geographic market that is in the same region as defined by Appendix D of Order No. 697, the 100 MW or more threshold would not be met because the increase in generation capacity is less than [100] MW in each generation market and, accordingly, a change in status filing would not be required.'' [115]

b. Proposal

96. We propose to clarify that the 100 MW reporting threshold in § 35.42(a)(1) is not limited only to markets previously studied. That is, if a seller acquires generation that would cause a cumulative net increase of 100 MW or more in any relevant geographic market (including generation in both the relevant geographic market itself and any first-tier/interconnected market with the potential to import into that market) since the seller's most recent triennial updated market power analysis or change in status filing, the seller must make a change in status filing. This would include cumulative increases of 100 MW or more in a new market that has not previously been studied because, once the seller has generation in that market, it is a relevant geographic market for that seller. We clarify that a net increase measures the difference between increases and decreases in affiliated generation. We further clarify that the example cited above from Order No. 697–A described a situation where the geographic market on which the Commission relied was not first-tier to the geographic market in which the seller acquired an additional 50 MW. Thus, we propose to clarify that the 100 MW threshold applies to the cumulative capacity added in any relevant geographic market, including what can be imported from first-tier markets, but does not cover situations where a seller acquires less than 100 MW in one market and less than 100 MW in another market, as long as those two markets are not first-tier to each other. We further propose to require that the 100 MW threshold requirement for change in status filings be calculated based on a generator's nameplate capacity rating because it is a single value, it exists for all types of generators, it is generally a more conservative value than a seasonal or five-year average rating would be, and it allows for uniform measurements across different types of generators.

97. Therefore, we propose to revise the regulatory text in § 35.42(a)(1) of the Commission's regulations to provide greater clarity and direction on this topic as follows: Ownership or control of generation capacity that results in *cumulative* net increases *(i.e., the difference between increases and*

[108] Order No. 697–C, FERC Stats. & Regs. ¶ 31,291 at P 17.

[109] For an example of the burden, the Commission received, in the most recent seven quarters, 90 filings from 1,380 filers. This is a reporting burden on the sellers and an inefficient use of Commission resources for information that has yet to produce an actionable item or elicit a single comment in almost five years. All 1,380 filers had to be listed in the notices and in the orders accepting the filings. Staff has written and issued seven orders accepting these filings, one order for each of the last seven quarters.

[110] *See* Order No. 697–D, FERC Stats. & Regs. ¶ 31,305 at P 23 (''[I]f there is a concern that a particular seller may be acquiring land for the purpose of preventing new generation capacity from being developed on that land, the Commission can request additional information from the seller at any time.'').

[111] 18 CFR 35.42(a).

[112] 18 CFR 35.42(a)(1).

[113] 18 CFR 35.42(a)(2).

[114] Order No. 697–A, FERC Stats. & Regs. ¶ 31,268 at P 512.

[115] *Id.* We note that the original text in Order No. 697–A stated ''the increase in generation is less than 50 MW in each generation market.'' However, it should have stated ''the increase in generation is less than 100 MW in each generation market.''

decreases in affiliated generation capacity) of 100 MW or more *of nameplate capacity in any relevant geographic market (including generation in the relevant geographic market and generation in any markets that are first tier to the relevant geographic market),* or of inputs to electric power production, or ownership, operation or control of transmission facilities, or

98. We seek comment on these proposals.

2. Long-Term Contracts

a. Current Policy

99. As noted above, sellers are currently required to report ownership or control of generation capacity that results in net increases of 100 MW or more but are not required to report contracts that do not convey ownership or control of generation capacity.[116]

b. Proposal

100. As discussed above, we propose to require sellers to report all long-term firm purchases of capacity and/or energy in their indicative screens, regardless of whether the seller has acquired control over the generation capacity supplying the power. The change in status reporting requirement in § 35.42 seeks to provide a timely report of ''any change in status that would reflect a departure from the characteristics the Commission relied upon in granting market-based rate authority.'' [117] We propose above to require reporting of long-term firm purchases in the indicative screens; such purchases will be relied upon in granting market-based rate authority. Therefore, in addition to the revisions proposed above, we propose to include such contracts when determining the 100 MW threshold and propose to revise the beginning of § 35.42(a)(1) of the Commission's regulations as follows: Ownership or control of generation capacity *or long-term firm purchases of capacity and/or energy* that results in net increases . . .[118]

101. We seek comment on this proposal.

3. New Affiliation and Behind-the-Meter Generation

a. Current Policy

102. Market-based rate sellers are required to make a change in status filing when they become affiliated with entities that: (1) Own or control generation; (2) own or control inputs to electric power production (e.g., intrastate natural gas transportation, storage, or distribution facilities); (3) own, operate or control transmission facilities; or (4) have a franchised service territory.[118] Currently, the 100 MW threshold for reporting increases in generation contained in § 35.42(a)(1) of the Commission's regulations does not apply to the requirement to report a new affiliation found in § 35.42(a)(2) of the Commission's regulations because the existing language in § 35.42(a)(2) does not reference the 100 MW threshold. As a result, § 35.42(a)(2) requires a change in status filing for *any* new affiliation, regardless of the amount of generation owned or controlled by the new affiliate.

103. In addition, the regulatory text states that a change in status filing is required for any new affiliate that owns or controls generation facilities, without regard to the size, type or characteristics of those facilities.[119] The Commission's experience is that some sellers are unsure if they should report new affiliates that own certain facilities such as qualifying facilities that are exempt from FPA section 205 [120] and behind-the-meter facilities.

104. Finally, the Commission's experience is that some sellers report the new acquisition or new affiliation in the text of their change in status filings but do not include the generation in the asset appendix, especially when it is behind-the-meter generation.

b. Proposal

105. We propose to revise the change in status regulations to include a 100 MW threshold for reporting new affiliations. That is, a market-based rate seller that has a new affiliation would not be required to file a change in status until its new affiliations result in a cumulative net increase of 100 MW or more of nameplate capacity in any relevant geographic market (including generation in both the relevant geographic market itself and any first-tier/interconnected market). As noted above, the Commission adopted a 100 MW threshold for reporting new generation, finding that a minimum reporting threshold strikes the proper balance between the Commission's duty to ensure that market-based rates are just and reasonable and the Commission's desire not to impose an undue regulatory burden on market-based rate sellers.[121] Similarly, we believe that applying the 100 MW threshold to new affiliations would ease the reporting burden on sellers without diminishing the Commission's ability to identify possible market power. Therefore, we propose to revise § 35.42(a)(2) of the Commission's regulations to read as follows:

Affiliation with any entity not disclosed in the application for market-based rate authority that*:* (i) (*proposing to delete*)[~~o~~]Owns or controls generation facilities *or has long-term firm purchases of capacity and/or energy that results in cumulative net increases (i.e., the difference between increases and decreases in affiliated generation capacity) of 100 MW or more of nameplate capacity in any relevant geographic market (including generation in the relevant geographic market(s) and generation in any markets that are first tier to the relevant geographic market(s)); (ii) Owns or controls* inputs to electric power production*:* ~~,~~ *(iii)* (*proposing to delete*)[affiliation with any entity not disclosed in the application for market-based rate authority that o]*O*wns, operates or controls transmission facilities*;*, or *(iv)* (*proposing to delete*)[affiliation with any entity that h]*H*as a franchised service area.

106. We further clarify that the requirement to submit a notice of change in status to report affiliation with new generation, transmission, or intrastate gas pipelines includes reporting that asset in the seller's appendix. We propose to amend the regulation to clarify that sellers must include all new affiliates and any assets owned or controlled by the new affiliates in the asset appendix. We propose to revise § 35.42(c) of the Commission's regulations as follows: When submitting a change in status notification regarding a change that impacts the pertinent assets held by a Seller or its affiliates with market-based rate authorization, a Seller must include an appendix of *all* assets*, including the new assets and/or affiliates reported in the change in status,* in the form provided in Appendix B of this subpart.

107. We further clarify that ''all assets'' include behind-the-meter generation and qualifying facilities.[122]

[116] *See* 18 CFR 35.42(a)(1).

[117] 18 CFR 35.42(a).

[118] 18 CFR 35.42(a)(2).

[119] *See id.*

[120] Sales of energy or capacity made by qualifying facilities 20 MW or smaller are exempt from section 205. Order No. 697–A, FERC Stats. & Regs. ¶ 31,268 at P 525; 18 CFR 292.601(c)(1).

[121] *Reporting Requirement for Changes in Status for Public Utilities with Market-Based Rate Authority,* Order No. 652, FERC Stats. & Regs. ¶ 31,175, at P 68, *order on reh'g,* 111 FERC ¶ 61,413 (2005).

[122] Accordingly, the appendix must list all generation assets owned (clearly identifying which affiliate owns which asset) or controlled (clearly identifying which affiliate controls which asset) by

Continued

However, we propose to allow sellers to aggregate their behind-the-meter generation by balancing authority area or market into one line on the list of generation assets. Similarly, we propose to allow sellers to aggregate their qualifying facilities under 20 MW by balancing authority area or market into one line on the list of generation assets.

108. We also clarify that sellers should include these assets in their indicative screens, as well as in their asset appendix. Sellers should also include this generation when calculating the 100 MW change in status threshold and the 500 MW Category 1 threshold.

109. We seek comment on these proposals.

D. Asset Appendix

1. Current Policy

110. Order No. 697 requires that market-based rate sellers include with each new application, market power analysis, and relevant change in status notification an asset appendix that lists all affiliates that have market-based rate authority and identifies any assets owned or controlled by the seller and any such affiliate.[123] The asset appendix includes two lists of assets. One list contains market-based rate affiliates and generation assets and the other list contains electric transmission and intrastate natural gas assets. The appendix must list all generation assets owned or controlled by the corporate family, and each asset's balancing authority area (clearly identifying which affiliate owns or controls which asset), geographic region, in-service date, and nameplate and/or seasonal ratings.[124] The transmission list of assets must reflect all electric transmission and natural gas intrastate pipelines and/or gas storage facilities owned or controlled by the corporate family and the location of such facilities.[125] The Commission requires the appendix of assets to be included in the form provided in Appendix B to Subpart H of Part 35 of the Commission's regulations, and provides an example of the required appendix on its Web site.[126]

2. Proposal

111. As detailed below, we propose clarifications and revisions to the required appendix that contains the lists of assets.

a. Changes to the Existing Columns

112. We propose to make three changes to the existing columns in the asset appendix. We propose to change the column headings on both lists of assets from ''Balancing Authority Area'' to ''Market/Balancing Authority Area'' to reflect the correct location for assets in organized markets as well as in balancing authority areas. The second proposal is to change the column headings on both lists of assets from ''Geographic Region (per Appendix D)'' to ''Geographic Region'' because there have been changes to some sellers' regions since the Commission originally published the region map in Appendix D of Order No. 697. Finally, we propose to change the heading for the ''Nameplate and/or Seasonal Rating'' column to ''Capacity Rating (MW): Nameplate, Seasonal, or Five-Year Average'' to clarify that this column requires capacity ratings in megawatts and to reflect that each submission of the asset appendix should use either ''nameplate,'' ''seasonal,'' or five-year average rating to reflect the rating used throughout the filing for a particular generation technology. These proposed changes will ensure consistency across filings and allow the industry and Commission staff to better utilize the information contained in the lists of assets.

113. Thus, we propose to modify the example of the required appendix found in Appendix B to Subpart H of Part 35 of the Commission's regulations to incorporate these changes.[127]

114. We seek comment on these proposed changes.

b. Clarifications Regarding the Existing Columns

115. The Commission's post-Order No. 697 experience has been that, with respect to the currently labeled ''Nameplate and/or Seasonal Rating'' column in the list of generation assets, some sellers report *only* the portion of the capacity that they own,[128] whereas other sellers report the entire capacity of the facility. Additionally, some sellers include in their asset lists generation facilities in which they have claimed a familial relationship through only passive, non-controlling interests.

116. We propose to clarify that, for the list of assets: (1) A seller must enter the entire amount of a generator's capacity (in MWs) in the ''Capacity Rating (MW): Nameplate, Seasonal, or Five-Year Average'' column even if the seller only owns part of a facility; (2) a seller should list only one of the following as a ''Use'' in the ''Asset Name and Use'' column: Transmission, intrastate natural gas storage, intrastate natural gas transportation, or intrastate natural gas distribution; (3) entities and generation assets in which passive ownership interests have been claimed should not be included in the horizontal market power indicative screens or reported in the appendix.[129] If a seller does not believe that the entire capacity of a generation facility should be included in its indicative screens, it may explain its position in the transmittal letter filed with its horizontal market power screens, including letters of concurrence where appropriate,[130] and thus account for only its portion of that particular generation facility in the indicative screens. However, the entire capacity of the facility should be reflected in the list of generation assets in the appendix. We note that generating units within a single plant may be aggregated in a single row if the information in the other columns is the same for all units, but separate plants cannot be aggregated in a single row, except for behind-the-meter generation, and qualifying facilities less than 20 MW, as proposed above. We further clarify that each asset should be listed only once; if it is owned by more than one affiliate, all affiliate names should be included in the ''Owned By'' column. If a company or an affiliate is registered in the Commission's company registration database,[131] we propose to clarify that the name in the asset appendix for that

the corporate family by balancing authority area, and by geographic region, and provide the in-service date and nameplate or seasonal ratings by unit. As a general rule, any generation assets included in a seller's market study should be listed in the asset appendix. Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 895.

[123] *Id.* P 894.

[124] *Id.* P 895.

[125] *Id.*

[126] The sample asset appendix can be found on the Commission's Web site at *http://www.ferc.gov/industries/electric/gen-info/mbr/appendix.pdf.*

[127] *See* Appendix B herein for an example of the proposed revised appendix.

[128] We note that the Commission has not permitted market-based rate sellers to dilute the ownership share of generation attributed to the seller or its affiliates based on multiplying successive shares of partial ownership in a company. *See Kansas Energy LLC,* 138 FERC ¶ 61,107, at P 28 (2012). Instead, sellers must account for generation capacity owned or controlled by the seller and its affiliates for purposes of analyzing horizontal market power. *See id.* P 37.

[129] We note that sellers must demonstrate why such ownership interests should be deemed passive. *See AES Creative Resources, L.P.,* 129 FERC ¶ 61,239 (2009).

[130] *See* Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 187.

[131] The term ''company registration database'' here refers to ''FERC's Online Company Registration application'' (*see http://www.ferc.gov/docs-filing/etariff/implementation-guide.pdf*). However, Commission orders have referred to this database as we have also issued orders referring to it as ''Company Registration,'' (*see Filing Via the Internet, Revisions to Company Registration and Establishing Technical Conference,* 142 FERC ¶ 61,097 (2013)) or ''Company Registration system'' (*see Order Updating Electric Quarterly Report Data Dictionary,* 146 FERC ¶ 61,169 (2014)).

company must appear exactly the same as in the registration database.

117. With respect to the ''Date Control Transferred'' column in both the generation and transmission asset lists, we clarify that the ''Date Control Transferred'' column should identify the date on which a contract that transfers control over a facility becomes effective. Where appropriate, companies may enter ''N/A'' in this field to indicate that it is not applicable to their asset(s).

118. With respect to the ''Size'' column in the list of transmission assets, we propose to clarify that the ''Size'' refers to both the length of the transmission line (i.e., feet or miles) and the capability of the line in voltage (kV). We note that companies can aggregate their transmission assets by voltage. For instance, a utility that owns a transmission system with several hundred transmission lines might include two rows in the transmission asset list; one row with 200 miles of 138 kV lines listed in the ''Size'' column and another row with 100 miles of 230 kV lines listed in the ''Size'' column as long as all the other columns (e.g., owned by, controlled by, balancing authority area, geographic region, etc.) remain the same for all assets aggregated in that row. The name for such aggregated facilities should describe the lines that are being aggregated, e.g., ''230 kV transmission lines.''

119. We seek comment on these proposals.

c. Changes Regarding OATT Waiver and Citations in Transmission Assets

120. The Commission has stated that even if a seller has been granted waiver of the requirement to file an OATT, those transmission facilities should be reported in its asset appendix,[132] and we believe that this should be reiterated and clarified going forward. Therefore, we propose to require any seller that has been granted waiver of the requirement to file an OATT for its facilities [133] to report in its list of transmission assets the citation to the Commission order granting the OATT waiver for those facilities. We propose to modify the example of the asset appendix found in Appendix B to Subpart H of Part 35 of the Commission's regulations to add a new column in the list of transmission assets for the citation to the Commission order accepting the OATT or granting waiver of the OATT requirement. This will make the list of transmission assets consistent with the list of generation assets, which already contains a column for the docket number in which market-based rate authority was granted, and will provide a more complete list of transmission assets to the Commission and the public. Providing the citation to the Commission order accepting the OATT or granting waiver of the OATT requirement in the list of transmission assets will facilitate the Commission's and market participants' verification that sellers were granted the appropriate authorizations.

121. We seek comment on these proposed changes.

d. Electronic Format

122. Currently, virtually all of the asset lists are submitted to the Commission using PDF format. Staff is unable to perform calculations on PDF files, or to search, or sort the data contained in the lists of assets. Staff therefore frequently transfers the information included in the lists of assets into spreadsheets for sorting, comparison purposes, and internal calculations, and has found numerous submission errors from sellers. If the Commission provided a sample electronic spreadsheet and required sellers to submit the lists of assets in an electronic spreadsheet, it would reduce filing burdens, improve accuracy, decrease the number of staff inquiries to sellers regarding submission errors, and result in a more efficient use of resources.

123. Therefore, we propose to require market-based rate sellers to submit the Appendix B asset lists in an electronic spreadsheet format that can be searched, sorted, and otherwise accessed using electronic tools. We propose to post on the Commission's Web site sample lists of assets in formatted electronic spreadsheets and to require sellers to submit all required appendices in the form and format of the sample electronic spreadsheets.[134]

124. We further propose to clarify that the lists of assets should not contain any information other than what is required in the respective columns. For instance, sellers frequently include footnotes in their appendices that cause the appendices to become unwieldy and difficult to read or understand. Sellers sometimes explain in these footnotes that some facilities are partially owned, that some affiliates included in their lists may not actually be affiliates but are included out of an abundance of caution, or that a facility is expected to come on-line or off-line at some future date. We discourage any such footnotes and direct that any such representations be made in the filing transmittal letter.

125. An example of the electronic spreadsheet for the appendix with the new columns and column headings is included as Appendix B herein.

e. Database

126. As noted above, we propose to require market-based rate sellers to submit their lists of assets in an electronic spreadsheet that can be searched, sorted, and otherwise accessed using electronic tools. In addition, we seek comment whether in the future it would be beneficial to develop a comprehensive searchable public database of the information contained in the asset appendices, which would eventually replace the pre-formatted spreadsheet. Such an approach would allow market-based rate sellers to update their asset appendices when circumstances change. We seek input regarding whether such a database would be useful, how the database might be created, standardized and maintained, and the frequency with which it should be updated. We further seek input on the usefulness of including unique identifiers for the affiliate companies and generation assets in such a database, e.g., the Company Registration database and the EIA Power Plant Code and Generator ID, respectively, where those IDs exist. We also seek input on the difficulty of reporting and the usefulness of including in such a database the percentage each affiliate owns of each of its assets.

127. We seek comment on these proposals.

E. Category 1 and Category 2 Sellers

1. Current Policy

128. In Order No. 697, the Commission created a category of market-based rate sellers (Category 1 sellers) that are exempt from the requirement to automatically submit updated market power analyses. Category 1 sellers include wholesale power marketers and wholesale power producers that own or control 500 MW or less of generation in aggregate per

[132] ''We clarify that the transmission facilities that we require to be included in that asset appendix are limited to those the ownership or control of which would require an entity to have an OATT on file with the Commission (even if the Commission has waived the OATT requirement for a particular seller).'' Order No. 697–A, FERC Stats. & Regs. ¶ 31,268 at P 378.

[133] *See* Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 408.

[134] If a seller chooses to create its own workable electronic spreadsheet, the file it submits must have the same format as the sample spreadsheet on the Commission Web site. Specifically, it must have the same exact columns and descriptive text as the sample spreadsheet. The file must be submitted in one of the spreadsheet file formats accepted by the Commission for electronic filing. *See* FERC, Acceptable File Formats (January 2012), *available at http://www.ferc.gov/docs-filing/elibrary/accept-file-formats.asp.*

region;[135] that do not own, operate or control transmission facilities other than limited equipment necessary to connect individual generating facilities to the transmission grid (or have been granted waiver of the requirements of Order No. 888); that are not affiliated with anyone that owns, operates or controls transmission facilities in the same region as the seller's generation assets; that are not affiliated with a franchised public utility in the same region as the seller's generation assets; and that do not raise other vertical market power issues.[136] Category 2 sellers (those market-based rate sellers that do not qualify as Category 1 sellers) are required to file regularly scheduled updated market power analyses.[137]

129. In practice, the criteria for Category 1 seller status have been applied differently in the case of power marketers (i.e., a seller that does not own generation or transmission) and power producers (i.e., a seller with generation assets).[138] The seller category status for a power marketer is determined by considering all affiliated generation and transmission, while power producers owning generation or transmission assets only have to consider affiliated generation if it is located in the same region as the power producer's generation assets.

2. Proposal

130. We propose to clarify the distinction in determining the seller category status of power marketers and power producers.[139] For purposes of determining seller category status for each region, a power marketer should include all affiliated generation capacity in that region. Power producers only need to include affiliated generation that is located in the same region as the power producer's generation assets. The reason behind this distinction is that a power marketer with no generation assets in the ground is assumed to have no home market; it is thus assumed to be equally likely to make sales in any region. However, although a power producer has authorization to make sales in other regions, it is assumed that the majority of its sales will be in the region(s) in which it owns generation assets.

131. Thus, we propose to clarify that a power marketer with no generation assets may qualify as a Category 1 seller in any region where: (1) Its affiliates own or control, in aggregate, 500 MW or less of generation capacity; (2) it is not affiliated with anyone that owns, operates or controls transmission facilities; (3) it is not affiliated with a franchised public utility; and (4) it does not raise other vertical market power issues. In addition, for any region where the power marketer's affiliates are designated as Category 2 sellers, it is Commission practice that the power marketer is also a Category 2 seller. We note that the above is consistent with the way in which the Commission has viewed power marketers since the issuance of Order No. 697.

132. We also propose to clarify that a power producer may qualify as a Category 1 seller in any region in which the power producer itself owns generation and the power producer and its affiliates own or control, in aggregate, 500 MW of generation capacity or less, as long as the power producer is not affiliated with anyone that owns, operates or controls transmission facilities in that region, is not affiliated with a franchised public utility in that region, and does not raise other vertical market power issues. In addition, unlike power marketers, a power producer may qualify as a Category 1 seller in a region where the power producer itself does not own or control any generation or transmission assets but where it has affiliates that are Category 2 sellers.[140]

133. Therefore, we propose to revise the regulations to clarify that to qualify for Category 1 status, a seller must meet *all* of the requirements. Failure to satisfy *any* of these requirements results in a Category 2 designation. The proposed change of the text of 18 CFR 35.36(a)(2) is: *A Category 1 Seller* means *a Seller that:*

(i) Is either a wholesale power marketer(proposing to delete)[s] *that controls or is affiliated with500 MW or less of generation in aggregate per region or a* wholesale power producers that own*s,* (proposing to delete)[or] control*s or is affiliated with* 500 MW or less of generation in aggregate *in the same region as its generation assets;*

(ii) (proposing to delete)[that do] *Does* not own, operate or control transmission facilities other than limited equipment necessary to connect individual generating facilities to the transmission grid (or *has* (proposing to delete)[have] been granted waiver of the requirements of Order No. 888, FERC Stats. & Regs. ¶ 31,036);

(iii) (proposing to delete)[that are] *Is* not affiliated with anyone that owns, operates or controls transmission facilities in the same region as the *S*eller's generation assets;

(iv) (proposing to delete)[that are] *Is* not affiliated with a franchised public utility in the same region as the *S(proposing to delete)*[s]eller's generation assets; and

(v) (proposing to delete)[that do] *Does* not raise other vertical market power issues.

134. We seek comment on this proposal.

F. Corporate Families

1. Corporate Organizational Charts

a. Current Policy

135. The Commission currently requires new and existing market-based rate sellers to provide written descriptions of their affiliates and corporate structure or upstream ownership for initial applications for market-based rate authority, updated market power analyses and notices of change in status as a result of new affiliations. In Order No. 697–A, the Commission stated:

> A seller seeking market-based rate authority must provide information regarding its affiliates and its corporate structure or upstream ownership. To the extent that a seller's owners are themselves owned by others, the seller seeking to obtain or retain market-based rate authority must identify those upstream owners. Sellers must trace upstream ownership until all upstream

[135] In Order No. 697, the Commission adopted a regional schedule for the submission of updated market power analyses based on the balancing authority area in which the seller owns or controls generation. The Commission established the following six geographic regions: Northeast, Southeast, Central, Southwest Power Pool, Southwest, and Northwest. Order No. 697, FERC Stats. & Regs. ¶ 31,252 at Appendix D. We provide an updated region map as Appendix D of this NOPR.

[136] *See id.* PP 848–849 n.1000; *see also* 18 CFR 35.36(a)(2), 35.37(a)(1).

[137] 18 CFR 35.36(a)(3), 35.37(a)(1).

[138] The distinction between the category status of power marketers and power producers was previously articulated in the March 2010 market-based rate technical conference. *FERC, Technical Conference on Preparation of Market-Based Rate Filings Quarterly Reports by Public Utilities,* Docket No. AD10–4–000 (2010), *available at https://www.ferc.gov/EventCalendar/EventDetails.aspx?ID=5089&CalType=%20&CalendarID=116&Date=03/03/2010&View=Listview*).

[139] The Commission regulations define Category 1 sellers as ''wholesale power marketers and wholesale power producers that own or control 500 MW or less of generation in aggregate per region; that do not own, operate or control transmission facilities other than limited equipment necessary to connect individual generating facilities to the transmission grid (or have been granted waiver of the requirements of Order No. 888, FERC Stats. & Regs. ¶ 31,036); that are not affiliated with anyone that owns, operates or controls transmission facilities in the same region as the seller's generation assets; that are not affiliated with a franchised public utility in the same region as the seller's generation assets; and that do not raise other vertical market power issues.'' 18 CFR 35.36(a)(2).

[140] We note that a mitigated seller cannot use an affiliated power producer in another region as a conduit to sell in a mitigated balancing authority area because all affiliates of a mitigated seller are prohibited from selling at market-based rates in any balancing authority area or market where the seller is mitigated. Order No. 697–A, FERC Stats. & Regs. ¶ 31,268 at P 335.

owners are identified. Sellers must also identify all affiliates. Finally, an entity seeking market-based rate authority must describe the business activities of its owners, stating whether they are in any way involved in the energy industry.[141]

b. Proposal

136. We propose to require sellers to provide an organizational chart, in addition to written descriptions of their affiliates and corporate structure or upstream ownership, for initial applications for market-based rate authority, updated market power analyses and notices of change in status reporting new affiliations.

137. The Commission has seen increasingly complex organizational structures as private equity funds and other financial institutions take ownership positions in generation and utilities. The Commission believes that requiring the filing of an organizational chart for initial applications for market-based rate authority, updated market power analyses and notices of change in status reporting new affiliations would make reviewing market-based rate filings more efficient, increase transparency, and synchronize information about corporate structure that the Commission receives from sellers with market-based rate authority with similar information that the Commission receives under section 203 of the FPA.[142] We propose to require from market-based rate sellers an organizational chart similar to that which the Commission requires from section 203 applicants. Specifically, § 33.2(c)(3) of the Commission's regulations[143] provides that section 203 applicants must include: a description of the applicant, including, among other things, ''[o]rganizational charts depicting the applicant's current and proposed post-transaction corporate structures (including any pending authorized but not implemented changes) indicating all parent companies, energy subsidiaries and energy affiliates unless the applicant demonstrates that the proposed transaction does not affect the corporate structure of any party to the transaction.'' We propose that market-based rate sellers be required to provide written descriptions of their affiliates and corporate structure or upstream ownership and an organizational chart depicting the market-based rate seller's current corporate structures (including any pending authorized but not implemented changes) indicating all upstream owners, energy subsidiaries and energy affiliates. We believe that the increased burden on market-based rate sellers is minimal as most sellers have this organizational chart available.

138. Thus, we propose to revise the regulatory text in § 35.37(a)(2) of the Commission's regulations as follows: When submitting a market power analysis, whether as part of an initial application or an update, a Seller must include an appendix of assets, in the form provided in Appendix B of this subpart, *written descriptions of their affiliates and corporate structure or upstream ownership, and an organizational chart. The organizational chart must depict the Seller's current corporate structure indicating all upstream owners, energy subsidiaries and energy affiliates.*

139. We also propose that such organizational chart be required for any notice of change in status involving a change in the ownership structure that was in place the last time the seller made a market-based rate filing with the Commission. Therefore, we propose to revise the regulatory text in § 35.42(c) of the Commission's regulations as follows: When submitting a change in status notification regarding a change that impacts the pertinent assets held by a Seller or its affiliates with market-based rate authorization, a Seller must include an appendix of assets in the form provided in Appendix B of this subpart, *written descriptions of their affiliates and corporate structure or upstream ownership, and an organizational chart. The organizational chart must depict the Seller's prior and new corporate structures indicating all upstream owners, energy subsidiaries and energy affiliates unless the Seller demonstrates that the change in status does not affect the corporate structure and the Seller's affiliations.[144]*

140. We seek comment on these proposals.

2. Single Corporate Tariff

a. Current Policy

141. Joint tariffs may be used when a corporate family has more than one affiliated seller with market-based rate authority.[145] Joint tariffs allow corporate families to more clearly organize their tariff records and simplify their tariff filings. The Commission explained in Order No. 714 that joint filers are permitted to designate one market-based rate seller (the designated filer) to file a single tariff (joint master corporate tariff) for inclusion in the Commission's eTariff database that reflects the joint tariff for itself and all affiliated sellers.[146] The Commission further explained that all affiliated sellers (i.e., the non-designated joint filers) would include in their respective tariff filings a tariff section consisting of a single page or section that would provide the appropriate name of the tariff and the identity of the designated filer for the joint tariff. In this way, non-designated filers incorporate by reference the joint master corporate tariff submitted by the designated filer, and staff and the general public are able to find quickly the appropriate joint master corporate market-based rate tariff in the Commission's eTariff database.

142. Several corporate families have successfully submitted a joint master corporate market-based rate tariff; however, others have experienced technical and non-technical difficulties when filing their tariff records into the Commission's electronic tariff database. Other corporate families continue to maintain their market-based rate tariffs separately. Having a joint master corporate market-based rate tariff eases the regulatory burden on corporate families because only the designated filer is required to submit tariff revisions, such as when mitigation is changed for the entire corporate family or when Commission-approved or required language in the tariff needs updating, and results in a more efficient use of seller and agency resources.

b. Proposal

143. We clarify on the Commission's Web site how a corporate family that chooses to submit a joint master corporate tariff should identify its designated filer and what each of the other filers should submit into their respective eTariff databases. That information can be found on the Commission's Web site at *http://*

[141] *Id.* P 181 n.258.

[142] 16 U.S.C. 824b.

[143] *See* 18 CFR 33.2(c)(3).

[144] When the changes to § 35.42(c) as proposed here are combined with the changes to § 35.42(c) proposed above, the revised § 35.42(c) would read as follows: When submitting a change in status notification regarding a change that impacts the pertinent assets held by a Seller or its affiliates with market-based rate authorization, a Seller must include an appendix of *all* assets, *including the new assets and/or affiliates reported in the change in status,* in the form provided in Appendix B of this subpart, *written descriptions of their affiliates and corporate structure or upstream ownership, and an organizational chart. The organizational chart must depict the Seller's prior and new corporate structures indicating all upstream owners, energy subsidiaries and energy affiliates unless the Seller demonstrates that the change in status does not affect the corporate structure and the Seller's affiliations.*

[145] *Electronic Tariff Filings,* Order No. 714, FERC Stats. & Regs. ¶ 31,276, at P 60 (2008).

[146] *See id.* P 63.

www.ferc.gov/industries/electric/gen-info/mbr/tariff/joint.asp.

G. Clarification of Commission Language in Performing SIL Studies

1. Current Policy

a. OASIS Practices

144. The Commission adopted the requirement that the SIL study be used in both the indicative screens and the DPT analysis as the basis for establishing the amount of power that can be imported into the relevant geographic market.[147] The Commission also stated that the SIL study shown in Appendix E of the April 14, 2004 Order is the only study that meets this requirement.[148]

145. The Commission's OASIS requirements are intended to ensure that potential transmission customers receive access to information that will enable them to obtain transmission service on a non-discriminatory basis from any transmission provider. The transmission provider's OASIS provides, among other things, information by electronic means about ATC for point-to-point service and provides a process for requesting transmission service.[149]

b. SIL Studies and OASIS Practices

146. In Order No. 697, the Commission found that SIL studies performed by sellers ''should not deviate from'' and ''must reasonably reflect'' the seller's OASIS operating practices and ''techniques used must have been historically available to customers.'' [150] Order No. 697 also stated that

> [b]y OASIS practices, we mean sellers shall use the same OASIS methods and studies used historically by sellers (in determining simultaneous operational limits on all transmission lines and monitored facilities) to estimate import limits from aggregated first-tier control areas into the study area.[151]

147. Furthermore, the April 14, 2004 Order requires that the seller consider ''all internal/external contingency facilities and all monitored/limiting facilities that were used historically to approximate area-area transmission availability'' and utilize scaling methods ''according to the same methods used historically in assessing available transmission for non-affiliate resources.'' [152]

148. Similarly, in *Pinnacle West,*[153] the Commission found that ''simultaneous transmission import capability used in the market screens should account for how transmission is actually provided by the applicant,'' explaining that ''simultaneous transmission import capability calculations should be based on actual historic conditions.'' [154]

149. Additionally, in *Carolina Power & Light,* the Commission clarified footnote 361 of Order No. 697, stating that ''in performing SIL studies, applicants should follow OASIS practices historically used by the study area and aggregated first-tier balancing authority areas.'' [155]

150. In *Puget,* the Commission largely reiterated and consolidated direction previously provided in Order No. 697, the April 14, 2004 Order, *Pinnacle West,* and *Carolina Power & Light.* The Commission clarified that sellers must ''[p]rovide copies of all Operating Guide descriptions that were applied in the Scaling section,'' as well as any operating guides used to ignore limiting elements in the SIL study results.[156] In addition, the Commission stated that applicants must exclude study area non-affiliated load from study area native load, and should not include first-tier generation serving study area non-affiliated load in net area interchange.[157] Finally, the Commission required that applicants document all instances where the SIL study differs from historical practices.[158]

151. The April 14, 2004 Order further requires that power flow benchmark cases should represent ''operational practices historically used'' and ''reasonably simulate the historical conditions that were present.''[159] Historical conditions include

> facility/line deratings used to maintain capacity benefit margins (CBM) and transmission reliability (TRM/CBM), actual unit dispatch used to fulfill network and firm reservation obligation, the actual peak demand, generator operating limits opposed on all resources in real time, other limits/constraints imposed by the [Transmission Provider] TP during the season peaks.[160]

152. In addition, Order No. 697 requires that power flow cases ''represent the transmission provider's tariff provisions and firm/network reservations held by seller/affiliate resources during the most recent seasonal peaks.'' [161]

153. In *Puget,* the Commission stated that ''[l]ong-term firm transmission reservations for applicant/affiliate generation resources that serve study area load reduce the amount of study area transmission capability available to potential competitors'' and that ''[f]ailing to properly account for such reservations is inconsistent with the Commission's methodology for calculating SIL values.'' [162]

154. In addition, the Commission stated that the transmission capability associated with study area long-term firm import transmission reservations also must be subtracted from the study area's native load to accurately represent the amount of study area native load available to be served by first-tier area generation.[163] This direction is reflected in Row 8 of Submittal 1 found in Appendix B of *Puget.*[164]

c. Simultaneous TTC

155. Order No. 697 allows the use of simultaneous TTC values in performing SIL studies. The Commission stated that this was permissible ''provided that these TTCs are the values that are used in operating the transmission system and posting availability on OASIS.'' The Commission required sellers to provide evidence that simultaneous TTC values account for simultaneity, internal and first-tier external transmission limitations, and transmission reliability margins; and are used in operating the transmission system and posting availability on OASIS.[165]

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[147] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 19.

[148] *Id.* (citing April 14, 2004 Order, 107 FERC ¶ 61,018 at Appendix E). The April 14, 2004 Order predates Order No. 697. However, Order No. 697 largely adopts the requirements of the April 14, 2004 Order. *Id.* PP 19, 354–362.

[149] 18 CFR 37.2, 37.6(b).

[150] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 354 (citing *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities,* Notice of Proposed Rulemaking, FERC Stats. & Regs. ¶ 32,602, at PP 77, 78 (2006)).

[151] *Id.* n.361.

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

[153] *Pinnacle West Capital Corp.,* 109 FERC ¶ 61,295 (2004), *clarified,* 110 FERC ¶ 61,127 (2005) (*Pinnacle West*). *Pinnacle West* predates Order No. 697. However, Order No. 697 largely affirms statements made in *Pinnacle West.* Order No. 697, FERC Stats. & Regs. ¶ 31,252 at PP 354–362.

[154] *Pinnacle West,* 110 FERC ¶ 61,127 at P 8.

[155] *Carolina Power & Light Co.,* 128 FERC ¶ 61,039, at P 7 (*Carolina Power & Light*), *clarified,* 129 FERC ¶ 61,152 (2009).

[156] *Puget,* 135 FERC ¶ 61,254 at Appendix B, Reporting Requirements for Submittals 8, 9.

[157] *Id.* at Reporting Requirements for Submittal 10.

[158] *Id.* at Reporting Requirements for Submittal 11.

[159] April 14, 2004 Order, 107 FERC ¶ 61,018 at Appendix E.

[160] *Id.*

[161] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 354.

[162] *Puget,* 135 FERC ¶ 61,254 at P 15.

[163] *Id.* P 16.

[164] *Id.* at Appendix B.

[165] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 364.

156. In Order No. 697–A, the Commission clarified that ''the use of simultaneous TTC values in the SIL study must properly account for all firm transmission reservations, transmission reliability margin, and capacity benefit margin.'' [166]

2. Proposal

157. We propose to provide clarification regarding several issues that have arisen regarding the proper way to perform SIL studies. In particular, the we propose clarification on issues relating to what is included in ''OASIS practices,'' how to deal with conflicts between OASIS practices and the Commission directions provided in Appendix B of *Puget,* and the correct load value to use in the SIL study.

158. The purpose of the SIL study is to calculate the total simultaneous import capability available to first-tier uncommitted generation resources, while also considering system limitations and existing resource commitments (i.e., long-term firm transmission reservations). Therefore, the methodology a transmission provider uses to calculate simultaneous TTC values [167] must be consistent with the methodology used for calculating and posting ATC and for evaluation of firm transmission service requests, consistent with Commission policy and precedent. Import capability available to a transmission provider during real-time operations should not be included in the transmission provider's SIL value if such import capability is not available to non-affiliated uncommitted generation resources requesting long-term firm transmission service. The following clarifications are therefore proposed.

a. OASIS Practices

159. As discussed above, the methodology a transmission provider uses to calculate SIL values must be consistent with the methodology it uses for calculating and posting ATC [168] and for evaluating transmission service requests. We propose the following clarifications:

160. We propose to clarify that the term ''OASIS practices'' refers specifically to the seasonal benchmark power flow case modeling assumptions, study solution criteria,[169] and operating practices historically used by the first-tier and study area transmission providers [170] to calculate and post ATC and to evaluate requests for firm transmission service.[171]

161. Second, we propose to clarify that in performing a SIL study the transmission provider must utilize its OASIS practices consistent with the administration of its tariff. The seasonal benchmark power flow cases submitted with a SIL study should represent historical operating practices only to the extent that such practices are available to customers requesting firm transmission service. For example, if the transmission provider does not allow the use of an operating guide when evaluating firm transmission service requests, the transmission provider should not be allowed to use the operating guide when calculating SIL values.[172]

b. SIL Studies and OASIS Practices

162. Where there is a conflict between the transmission provider's tariff or OASIS practices and the directions specified in the *Puget* order for performing SIL studies, we propose to clarify that sellers should follow OASIS practices except as noted below. Sellers are reminded that, in instances where actual OASIS practices differ from the SIL direction provided in *Puget,* sellers should both use actual OASIS practices and provide documentation specifically identifying such practices.[173] We propose to clarify that to the extent that a seller's SIL study departs from actual OASIS practices,[174] such departures are only permitted where use of actual OASIS practices is incompatible with an analysis of import capability from an aggregated first-tier area. We invite comments identifying potential areas where actual OASIS practices may be incompatible with the performance of SIL studies.

163. Further, we remind sellers that the calculated SIL value should account for any limits defined in the tariff, such as stability or voltage.[175] If a seller utilizes a direct current analysis when performing a SIL study, but an alternating current analysis when evaluating transmission service requests, the seller must validate the total aggregate transfer level value, consistent with the transmission provider's OASIS practices, if modeled using an alternating current load flow model.[176]

164. We also reiterate that sellers may use load scaling to perform a SIL study if they use load scaling in their OASIS practices, ''provided they submit adequate support and justification for the scaling factor used in their load shift methodology and how the resulting SIL number compares had the company used a generation shift methodology.'' [177]

165. Further, we propose to clarify that when properly accounting for long-term firm transmission reservations for generation resources that serve study area load, sellers must reduce the simultaneous TTC value [178] by

[166] Order No. 697–A, FERC Stats. & Regs. ¶ 31,268 at P 142.

[167] *See* Row 4 of proposed Submittal 1 (Total Simultaneous Transfer Capability).

[168] Section 15.2 (Determination of Available Transfer Capability) of the *pro forma* OATT states ''[i]n the event sufficient transfer capability may not exist to accommodate a service request, the Transmission Provider will respond by performing a System Impact Study.'' *See Preventing Undue Discrimination and Preference in Transmission Service,* Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh'g,* Order No. 890–A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g,* Order No. 890–B, 123 FERC ¶ 61,299 (2008), *order on reh'g,* Order No. 890–C, 126 FERC ¶ 61,228 (2009), *order on clarification,* Order No. 890–D, 129 FERC ¶ 61,126 (2009).

[169] Study solution criteria may include but are not limited to distribution factor thresholds, transformer tap adjustments, reactive power limits, transmission equipment ratings, and model solution settings.

[170] We reiterate that, while entities may not be familiar with all of the OASIS practices of transmission providers in first-tier balancing authority areas, they should at least be familiar with major constraints, path limits, and delivery problems in neighboring transmission systems. *See* Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 354 n.361.

[171] While the OASIS practices associated with non-firm transmission service may result in a higher SIL value, the interruptible nature of such service makes it inappropriate as a measure of uncommitted generation capacity in the first-tier available to compete in the study area.

[172] By ''operating guide'' we are generally referring to the NERC defined term ''Operating Procedure,'' which is defined as ''a document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s).'' *See* NERC, Glossary of Terms Used in NERC Reliability Standards 53 (2014), *http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.* In the SIL study context, this may include switching procedures, special protection systems, load throw-over schemes, temporary transmission line rating changes, and other actions that are not typically represented in the seasonal benchmark power flow models.

[173] *See* Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 356.

[174] *See Puget,* 135 FERC ¶ 61,254 at Appendix B.

[175] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 346.

[176] *See Pinnacle West Capital Corporation,* 117 FERC ¶ 61,316, at P 11 n.19 (2006) (''The resulting loading and voltages for the limiting cases, if derived from DC (direct current) load flow analysis would have been verified by AC (alternating current) load flow analysis and demonstrated to be within the applicable system operating limits as dictated by thermal, voltage or stability considerations to ensure system reliability. The Commission requires that such comparisons be included in the applicant's working papers that are submitted to the Commission.'').

[177] Order No. 697–A, FERC Stats. & Regs. ¶ 31,268 at P 145.

[178] The revised Standard Screen Format (*e.g.,* Rows B1 and M1 in the market share screen (Long-Term Firm Purchases (from outside the study area))) must reflect the long-term firm reservations from Submittal 1, Table 1, Row 5 of *Puget. Puget,* 135 FERC ¶ 61,254 at Appendix B.

subtracting all long-term firm import transmission reservations.[179] The Commission has already provided guidance with respect to accounting for long-term firm transmission reservations into the study area from affiliated generation resources located outside the study area.[180] The proposed revised Appendix A Standard Screen Format accounts for all long-term firm import transmission reservations into the study area.[181] Therefore, we propose to direct applicants to subtract all long-term firm import transmission reservations, including reservations held by non-affiliated sellers, from the simultaneous TTC value. We propose revisions to Submittal 2 to account for these non-affiliate long-term firm reservations. Accounting for all long-term firm reservations ensures that the determination of the SIL study value is consistent with the method used to allocate this value to uncommitted generation capacity in the aggregated first-tier area for the indicative screens. Sellers should refer to Submittal 1 for further information.

166. Finally, we propose to clarify that sellers must account for wheel through transactions where such transactions are used to serve a non-affiliated load that is embedded within a study area. Specifically, the seller should reduce the simultaneous TTC value by subtracting the value of all wheel-through transactions. These transactions should be accounted for as long-term firm import transmission reservations, and reported in Submittal 2. We propose revisions to Submittal 2 to account for wheel-through transactions. While such generation is not used to serve study area load, it still reduces the amount of transmission capability available to first-tier generators competing to serve study area load.

167. We propose to clarify that, where a first-tier market or balancing authority area is directly interconnected to the study area only by controllable tie lines[182] and is not interconnected to any other first-tier market or balancing authority area, sellers should follow their OASIS practices regarding calculation and posting of ATC for such areas. If sellers' OASIS practices are incompatible with the SIL study (e.g., ATC is based on tie line rating), sellers may use an alternative process to account for import capability for such tie lines. We propose to further clarify that, in such circumstances, it will be presumed reasonable to model a controllable tie line as a single equivalent first-tier generator connected to the study area by a radial line with a rating equal to the rating of the controllable tie line. Sellers should document any instances where modeling of controllable tie lines deviates from OASIS practices, and explain such deviations, including: How tie line flow is accounted for in net area interchange; how tie line flow is scaled or otherwise controlled when calculating simultaneous incremental transfer capability; and how to account for long-term firm transmission reservations over controllable tie lines.

168. To the extent that the study area is directly interconnected to first-tier areas by controllable merchant transmission lines (e.g., Linden VFT), sellers should properly account for capacity rights on such lines. If sellers hold long-term capacity rights on such lines, these rights should be accounted for as long-term firm transmission reservations. If sellers lack sufficient knowledge regarding the existence and attributes of capacity rights on controllable merchant lines, they shall assume the full capacity of such lines is held by sellers with long-term firm transmission reservations.

169. As an initial matter, we reiterate that the SIL study is ''intended to provide a reasonable simulation of historical conditions'' and is not ''a theoretical maximum import capability or best import case scenario.''[183] Order No. 697 stated that the SIL study ''is a study to determine how much competitive supply from remote resources can serve load in the study area.''[184] The Commission clarified in *Puget* that sellers should not report study area non-affiliated load as study area native load, and should adjust modeled net area interchange by the same amount.[185] However, the exclusion of all study area non-affiliated load may result in SIL values that are inconsistent with the intent of the indicative screens. Furthermore, in the event the SIL value is limited by study area load, restricting study area load to affiliated load fails to account for import capability that may be used to serve wholesale load customers. Therefore, we propose to require sellers to include all load associated with balancing authority area(s) within the study area. Sellers should only adjust the reported value for modeled net area interchange to account for first-tier generation serving load associated with a first-tier balancing authority area that is modeled as part of the study area.[186] To ensure Submittal 1 is consistent with these requirements, we propose to revise Row 8 to read ''Adjusted Historical Peak Load'' (instead of ''Study area adjusted native load'').

170. We are also looking for consistent, reported load values for all sellers to use in preparing SIL studies. *Puget,* Appendix B, Submittal 1 requires sellers to use FERC Form No. 714 load values or explain the source of the data used. Some sellers have commented that the load values in their models differ from Form No. 714 data and have sought to rely on data from sources other than FERC Form No. 714. We seek industry comment on what sources other than FERC Form No. 714 may be appropriate sources to rely on in determining historical peak load.

171. We clarify that the values provided in Submittal 1 should generally be supported by the submitted seasonal benchmark power flow models. In particular, we expect that Row 1 (Simultaneous Incremental Transfer Capability), Row 2 (Modeled Net Area Interchange), and Row 4 (Total Simultaneous Transfer Capability) should agree with the corresponding values from the seasonal benchmark power flow models. Any differences should be explained by the seller. We propose to update Submittal 1, as reflected in Appendix E to this NOPR, to provide additional clarity on the expected values for certain rows.[187] We propose to post a new version of Submittal 1 on the Commission's Web site.

c. Simultaneous TTC

172. We propose to define standard guidance for data submittals and representations that sellers using the simultaneous TTC method must provide to the Commission. First, sellers must provide historical data of actual, hourly, real-time TTC values used for operating

[179] *See* Revised Appendix E, Submittal 1, Row 5.

[180] *Puget,* 135 FERC ¶ 61,254 at P 15.

[181] *See* Revised Appendix A, Standard Screen Format, specifically Rows A1, B1, E1 and F1 in the market share screen and Rows A1, B1, L1 and M1 in the pivotal supplier screen.

[182] Controllable tie lines include DC transmission facilities and AC transmission facilities with the ability to control the magnitude and direction of power flows through equipment such as converters, phase shifting transformers, variable frequency transformers, etc.

[183] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 354 (citing *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities,* Notice of Proposed Rulemaking, FERC Stats. & Regs. ¶ 32,602, at P 77 (2006)).

[184] *Id.* P 361.

[185] *Puget,* 135 FERC ¶ 61,254 at Appendix B.

[186] If the load is modeled as part of another area, i.e., as a non-area load attached to an area bus, and the net area interchange calculation includes both tie lines and non-area loads attached to area buses, net area interchange associated with service to such load should be approximately zero, and no adjustment will be necessary.

[187] *See* Revised Appendix E, Submittal 1.

the transmission system and posting availability on OASIS for each interface during each seasonal study period. Sellers should identify the date and hour from which simultaneous TTC values were calculated. Sellers may use the maximum sum of TTC values for any day and time during each season, so long as they also demonstrate that these TTC values are simultaneously feasible. Sellers may demonstrate that simultaneous TTC values are simultaneously feasible by performing a power flow study that verifies that the declared simultaneous TTC value is simultaneously feasible while accounting for all internal and external transmission limitations supplied in Appendix E and *Puget.* Sellers may also provide expert testimony explaining how the specific criteria and procedures used to calculate posted TTC values result in TTC values that are simultaneously feasible.

173. We reiterate that, in the event there are limited interconnections between first-tier markets, the Commission will review evidence that potential loop flow between first-tier areas is properly accounted for in the underlying SIL values on a case-by-case basis.[188] However, we clarify that simply attesting that first-tier markets or balancing authority areas are not directly interconnected is not sufficient evidence that TTC values posted on OASIS are simultaneous, as this does not preclude internal transmission limitations from limiting the simultaneous TTC below the sum of individual path TTC values.

174. We seek comment on these proposals.

H. Parts 101 and Part 141 Waivers

1. Current Policy

175. As noted in Order No. 697, the Commission has granted certain entities with market-based rate authority, such as power marketers and independent or affiliated power producers, waiver of the Commission's Uniform System of Accounts requirements, specifically waiver of Parts 41, 101, and 141 of the Commission's regulations, except §§ 141.14 and 141.15.[189] The Commission found that the costs of complying with the Uniform System of Accounts requirements, and specifically Parts 41, 101, and 141 of the Commission's regulations, outweigh any incremental benefits of such compliance where the seller only transacts at market-based rates.[190] However, the Commission typically does not grant market-based rate sellers waiver of §§ 141.14 and 141.15 of the Commission's regulations, which address certain reporting requirements applicable to hydropower licensees.[191]

2. Proposal

176. We clarify here that any waiver of Part 101 granted to a market-based rate seller is limited such that the waiver of the provisions of Part 101 that apply to hydropower licensees is not granted with respect to licensed hydropower projects. Hydropower licensees are required to comply with the requirements of the Uniform System of Accounts pursuant to 18 CFR Part 101 to the extent necessary to carry out their responsibilities under Part I of the FPA, particularly sections 4(b), 10(d) and 14 of the FPA.[192] We further note that a licensee's status as a market-based rate seller under Part II of the FPA does not exempt it from accounting responsibilities as a licensee under Part I of the FPA.[193] Thus, hydropower licensees that received waiver of Part 101 of the Commission's regulations as part of their market-based rate applications under Part II of the FPA are cautioned that such waivers do not relieve them of their obligations to comply with the Uniform System of Accounts to the extent necessary to carry out their responsibilities under Part I of the FPA with respect to their licensed projects.

177. We further direct market-based rate sellers that own licensed hydropower projects to ensure that their market-based rate tariffs reflect appropriate limitations on any waivers that previously have been granted. Specifically, to the extent that the hydropower licensee has been granted waiver of Part 101 as part of its market-based rate authority, the licensee's market-based rate tariff limitations and exemptions section should be revised to provide that the seller has been granted waiver of Part 101 of the Commission's regulations with the exception that waiver of the provisions that apply to hydropower licensees has not been granted with respect to licensed hydropower projects. Similarly, to the extent that a hydropower licensee has been granted waiver of Part 141 as part of its market-based rate authority, it should ensure that the limitation and exemptions section of its market-based rate tariff specifies that waiver of Part 141 has been granted, with the exception of §§ 141.14 and 141.15 (which pertain to the filing by hydropower licensees of Form No. 80, Licensed Hydropower Development Recreation Report, and the Annual Conveyance Report).[194]

178. These market-based rate tariff compliance filings are to be made the next time the hydropower licensee proposes a change to its market-based rate tariff, files a notice of change in status pursuant to 18 CFR 35.42, or submits an updated market power analysis in accordance with 18 CFR 35.37. In addition, going forward, any market-based rate seller requesting waivers of Parts 101 and/or 141 should include these limitations in their market-based rate tariffs, regardless of whether they own any licensed hydropower projects. This will ensure that hydropower licensees understand the limitations on Parts 101 and 141 waivers. To the extent that the market-based rate seller is not a licensee, these limitations should not have any effect as they only deny waiver of certain provisions affecting licensees. If a market-based rate seller becomes a hydro licensee after it receives market-based rate authority, it must file revisions to its market-based rate tariff to reflect the limitations in its Parts 101

[188] *Atlantic Renewables Projects II,* 135 FERC ¶ 61,227, at P 9 (2011).

[189] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at PP 976, 984.

[190] *Id.* P 985 (noting that the Commission has ''previously stated that Parts 41, 101 and 141 prescribe certain accounting and reporting requirements that focus on the assets that a utility owns, and waiver of these requirements is appropriate where the utility 'will not own any such assets, its jurisdictional facilities will be only corporate and documentary, its costs will be determined by utilities that sell power to it, and its earnings will not be defined and regulated in terms of an authorized return on invested capital' '').

[191] *See Electron Hydro, LLC,* 144 FERC ¶ 61,161, at P 23 (2013).

[192] In *Trafalgar Power Inc.,* 87 FERC ¶ 61,207, at 61,798 n.46 (1999) (*Trafalgar Power*), the Commission stated:

> Under [s]ection 14 of the FPA, the Federal government may take over a project upon expiration of the project's licensee, conditioned upon the government's payment to the licensee of the 'net investment of the licensee in the project or projects taken.' Section 4(b) requires licensees to file a statement showing the 'actual legitimate original cost of construction of such project' to enable the Commission to determine 'the actual legitimate cost of and the net investment in' the project. Section 10(d) requires licensees to establish an amortization reserve account that will reflect excess or surplus earnings of their licensed project if such earnings have accumulated in excess of a reasonable rate of return upon the 'net investment' in the project during a period beginning after the first twenty years of operations. Pursuant to [s]ection 10 (d) of the FPA the amount transferred to the amortization reserve may be used to reduce a licensee's net investment in the project, and if, after expiration of the license, the government takes over the project under [s]ection 14, it will be required to compensate the licensee for its net investment in the project, reduced by the amortization reserve for the project.

[193] *See Seneca Gen., LLC,* 145 FERC ¶ 61,096, at P 23 n.20 (2013) (citing *Trafalgar Power,* 87 FERC ¶ 61,207, at 61,798).

[194] *See Domtar Maine, LLC,* 133 FERC ¶ 61,207, at P 23 (2010).

and 141 waivers within 30 days of the effective date of its license.

I. Miscellaneous

1. Regional Reporting Schedule

179. Section 35.37(a)(1) of the Commission's regulations requires Category 2 sellers to submit a market power analysis ''every three years, according to the schedule contained in Order No. 697.'' [195] The Commission stated in Order No. 697 that Category 2 sellers ''will be required to file an updated market power analysis based on the schedule in Appendix D.'' [196] Concurrent with the issuance of this NOPR, we will post on the Commission's Web site an updated version of the schedule. Additionally, we propose to revise § 35.37(a)(1) as follows: In addition to other requirements in subparts A and B, a Seller must submit a market power analysis in the following circumstances: When seeking market-based rate authority; for Category 2 Sellers, every three years, according to the schedule (*proposing to delete*)[contained in Order No. 697, FERC Stats. & Regs. ¶ 31,252] *posted on the Commission's Web site;* or any other time the Commission directs a Seller to submit one. Failure to timely file an updated market power analysis will constitute a violation of Seller's market-based rate tariff.

180. We also include an updated region map in Appendix D of this NOPR.

2. Affirmative Statement

181. In Order No. 697, as part of the vertical market power analysis, the Commission stated that it would require sellers to make an affirmative statement that they have not erected barriers to entry into the relevant market and will not erect barriers to entry into the relevant market.[197] This requirement is codified at § 35.37(e)(4): ''In addition, a Seller is required to make an affirmative statement that it has not erected barriers to entry into the relevant market and will not erect barriers to entry into the relevant market.'' [198] In Order No. 697, the Commission stated that the obligation applies both to the seller and its affiliates, but is limited to the geographic market(s) in which the seller is located.[199] However, many sellers have not mentioned their affiliates when making their affirmative statements. Therefore, we propose to revise § 35.37(e)(4) (which is proposed elsewhere in this NOPR to be renumbered as § 35.37(e)(3)), as follows to make clear that the affirmative statement requirement applies to the seller and its affiliates: A Seller must ensure that this information is included in the record of each new application for market-based rates and each updated market power analysis. In addition, a Seller is required to make an affirmative statement that it *and its affiliates have (proposing to delete)*[has] not erected barriers to entry into the relevant market and will not erect barriers to entry into the relevant market.

IV. Information Collection Statement

182. The information collection requirements contained in this proposed rule are subject to review by the Office of Management and Budget (OMB) under section 3507(d) of the Paperwork Reduction Act of 1995 (PRA).[200] The OMB regulations require approval of certain reporting and recordkeeping requirements (collections of information) imposed by agency rules.[201] Upon approval of a collection of information, OMB will assign an OMB control number and expiration date. Respondents subject to the filing requirements of this rule will not be penalized for failing to respond to this collection of information unless the collection of information displays a valid OMB control number.

183. Comments are solicited on the Commission's need for this information, whether the information will have practical utility, the accuracy of the provided burden estimate, ways to enhance the quality, utility, and clarity of the information to be collected, and any suggested methods for minimizing the respondent's burden,[202] including the use of automated information techniques.

Calculated Burden

184. We propose to clarify and streamline the Commission's regulations, and to reduce the burden on entities seeking to obtain or retain market-based rate authority by revising existing market-based rate requirements under Subpart H to Part 35 of Title 18 of the Code of Federal Regulations. Specifically, as discussed below, three significant filing burdens will be reduced or eliminated by the proposed rule due to (1) eliminating the requirement for sellers in an RTO to file indicative screens; (2) creating a threshold for reporting new affiliations only if they result in a 100 MW or more cumulative change in generation capacity; and (3) discontinuing land acquisition reporting requirements for market-based rate sellers. As discussed below, other amendments in the proposed rule also are expected to reduce the filing burden on market-based rate sellers, but to a lesser extent.

185. Section 35.37 of the Commission's regulations currently requires market-based rate sellers to submit a horizontal market power analysis when seeking to obtain or retain market-based rate authority.[203] We propose to implement a streamlined procedure that will eliminate the requirement to file the indicative screens as part of a horizontal market power analysis for any seller in an RTO if the seller is relying on Commission-approved monitoring and mitigation to mitigate any potential market power it may have. Eliminating the requirement for RTO sellers to file indicative screens will reduce the burden of filing a horizontal market power analysis for a large portion of market-based rate sellers when filing updated market power analyses, initial applications for market-based rate authority, and notices of change in status.

186. We propose to further reduce the filing burden on market-based rate sellers by adopting a reporting threshold of a 100 MW cumulative net change in generation capacity for reporting changes in status regarding new affiliations. This change applies the 100 MW reporting threshold for new generation in 18 CFR 35.42(a)(1) to the reporting requirement for new affiliations in 18 CFR 35.42(a)(2). Under this proposed change, we expect that market-based rate sellers will file fewer changes in status, instead of reporting multiple acquisitions of small newly-affiliated generators in one filing. Given that a change in status filing typically includes a transmittal letter and a revised asset appendix and may also include indicative screens, we expect this change to reduce burdens on market-based rate sellers.

187. Section 35.42(d) of the Commission's regulations currently requires that all market-based rate sellers report on a quarterly basis the acquisition of site(s) that have the potential to be developed for new generation capacity of 100 MWs or

[195] 18 CFR 35.37(a)(1).

[196] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 850.

[197] *Id.* P 447.

[198] 18 CFR 35.37(e)(4).

[199] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 447.

[200] 44 U.S.C. 3507(d) (2012).

[201] 5 CFR 1320.11.

[202] The Commission defines burden as the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. For further explanation of what is included in the information collection burden, reference 5 CFR 1320.3.

[203] 18 CFR 35.37.

more.[204] The Commission proposes to eliminate the burden on all market-based rate sellers by discontinuing the quarterly land acquisition reporting requirement in § 35.42(d). The Commission also proposes to eliminate the provision in § 35.37(e)(2) requiring reporting of sites for generation capacity development as part of the vertical market power analysis.

Other Changes in Burden

188. In addition to the elimination of significant burdens to market-based rate sellers discussed above, we propose to revise a number of current market-based rate requirements in 18 CFR Part 35 to provide greater clarity to entities seeking to acquire and retain market-based rate authority. These revisions are expected to: (1) Reduce the need for clarification phone calls from market-based rate sellers and subsequent follow-up phone calls from staff; (2) reduce amendments filed to correct errors and the related processing delays; and (3) streamline existing requirements, thereby reducing the burden in future filings. We estimate that such measures will typically reduce burdens on market-based rate sellers. Some simplifications to the existing market-based rate requirements may create an initial, minimal one-time implementation burden for market-based rate sellers when the filing is first submitted.

189. The Commission is also making a few minor additions to the current requirements. These proposed additions include: (a) Providing organization charts (for initial applications for market-based rate authority, updated market power analyses and notices of change in status reporting new affiliations); (b) splitting some entries in Appendix A to provide more detail;[205] (c) citing the Order accepting the OATT in Appendix B; and (d) amendments to Submittal 2 to account for non-affiliate long-term firm reservations and wheel-through transactions.

190. However, any increases in burden (for the initial filing, such as downloading the new proposed spreadsheets, as well as ongoing additions) are expected to be greatly outweighed by the reduction in burden.

Public Reporting Burden: The Commission recently issued notices on the burden estimate for FERC–919.[206] The estimated total annual burden of 85,444 hours includes:

- Market power analysis in new applications for market-based Rates [18 CFR 35.37(a)], 53,250 hours;
- Triennial market power analysis in Category 2 seller updates [18 CFR 35.37(a)], 20,750 hours;
- Quarterly land acquisition reports [18 CFR 35.42(d)], 3,208 hours; and
- Change in status reports [18 CFR 35.42(a)], 8,236 hours.

191. In comparison, the total burden estimate for all market-based rate sellers after the Proposed Rule goes into effect is expected to be significantly lower. The total cost for market-based rate sellers after revising the market-based rate requirements is expected to be as follows:[207]

FERC–919, BURDEN AFTER IMPLEMENTATION OF PROPOSALS IN NOPR IN DOCKET NO. RM14–14

	Number of respondents (A)	Number of responses per respondent (B)	Total number of responses (A) × (B) = (C)	Average burden hours per response (D)	Estimated total annual burden hours (C) × (D)
New applications for market-based rates [18 CFR 35.37], With Screens	107	1	107	250	26,750
New applications for market-based rates [18 CFR 35.37], No Screens	106	1	106	120	12,720
Triennial market power analysis in Category 2 seller updates [18 CFR 35.37], With Screens	42	1	42	250	10,500
Triennial market power analysis in Category 2 seller updates [18 CFR 35.37], No Screens	41	1	41	120	4,920
Quarterly land acquisition reports [18 CFR 35.42(d)]	0	0	0	0	0
Change in status reports [18 CFR 35.42(a)], With Screens	13	1	13	250	3,250
Change in status reports [18 CFR 35.42(a)], No Screens	224	1	224	20	4,480
Total					62,620

192. After implementation of the proposed changes, the total estimated annual cost burden to respondents is $5,497,409.80 [62,620 hours * $87.79[208]) = $5,497,409.80]. This represents a reduction in total annual burden for FERC–919 of 22,824 hours[209] (to 62,620 hours from 85,444 hours) or a 27 percent reduction.

[204] 18 CFR 35.42(d).

[205] For example, we propose to split Row A (Installed Capacity) in the existing pivotal supplier screen into Row A (Installed Capacity (from inside the study area)) and Row A1 (Remote Capacity (from outside the study area)), with similar changes being made to currently defined Rows B, E, and F. Similar changes are proposed for the same rows in the market share screen.

[206] The Commission issued notices requesting comment in Docket No. IC14–2–000. *See* 78 FR 62,006 (Oct. 11, 2013); 79 FR 818 (Jan. 7, 2014). The FERC–919 and related burden estimates were approved by OMB on February 27, 2014.

[207] Order No. 697 included the burden for Appendix A Parts I and II. The burden was not modified when Appendix A Part II was inadvertently omitted in Order No. 697–A; the burden related to Appendix A Part II continues to be included in the FERC–919.

[208] The Commission estimates this figure based on the Bureau of Labor Statistics data (for the Utilities sector, at *http://www.bls.gov/oes/current/naics2_22.htm,* plus benefits information at *http://www.bls.gov/news.release/ecec.nr0.htm*). The salaries (plus benefits) for the three occupational categories are:

Economist: $74.29/hour

Electrical Engineer: $60.70/hour

Lawyer: $128.39/hour

The average hourly cost of the three categories is $87.79 [($74.29+$60.70+$128.39)/3].

[209] This includes reductions for: New applications for market-based rates of 13,780 hours; triennial market power analysis of 5,330 hours; quarterly land acquisition reports of 3,208 hours; and change in status reports of 506 hours.

Title: Proposed Revisions to Market Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities (FERC–919).

Action: Revision of Currently Approved Collection of Information.

OMB Control No.: 1902–0234.

Respondents for this Rulemaking: Public utilities, wholesale electricity sellers, businesses, or other for profit and/or not for profit institutions.

Frequency of Responses:

Initial Applications: On occasion.

Updated Market Power Analyses: Updated market power analyses are filed every three years by Category 2 sellers seeking to retain market-based rate authority.

Land Acquisitions: We propose to eliminate this requirement under the proposed rule.

Change in Status Reports: On occasion.

Necessity of the Information:

Initial Applications: In order to retain market-based rate authority, the Commission must first evaluate whether a seller has the ability to exercise market power. Initial applications help inform the Commission as to whether an entity seeking market-based rate authority lacks market power, and whether sales by that entity will be just and reasonable.

Updated Market Power Analyses: Triennial updated market power analyses allow the Commission to monitor market-based rate authority to detect changes in market power or potential abuses of market power. The updated market power analysis permits the Commission to determine that continued market-based rate authority will still yield rates that are just and reasonable.

Change in Status Reports: The change in status requirement permits the Commission to ensure that rates and terms of service offered by market-based rate sellers remain just and reasonable.

Internal Review: The Commission has reviewed the reporting requirements and made a determination that revising the reporting requirements will ensure the Commission has the necessary data to carry out its statutory mandates, while eliminating unnecessary burden on industry. The Commission has assured itself, by means of its internal review, that there is specific, objective support for the burden estimate associated with the information requirements.

Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director, email: *DataClearance@ferc.gov,* phone: (202) 502–8663, fax: (202) 273–0873]. Please send comments concerning the collection of information and the associated burden estimates to the Commission, and to the Office of Management and Budget, Office of Information and Regulatory Affairs, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: (202) 395–4638, fax: (202) 395–7285]. For security reasons, comments to OMB should be submitted by email to: *oira_submission@omb.eop.gov.* Comments submitted to OMB should include Docket Number RM14–14, FERC–919, and OMB Control Number 1902–0234.

V. Environmental Analysis

193. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[210] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment.[211] The actions proposed here fall within the categorical exclusions in the Commission's regulations for rules that are clarifying, corrective, or procedural, or do not substantially change the effect of legislation or regulations being amended.[212] In addition, the proposed rule is categorically excluded as an electric rate filing submitted by a public utility under sections 205 and 206 of the FPA.[213] As explained above, this proposed rule, which addresses the issue of electric rate filings submitted by public utilities for market-based rate authority, is clarifying in nature. Accordingly, no environmental assessment is necessary and none has been prepared in this NOPR.

VI. Regulatory Flexibility Act

194. The Regulatory Flexibility Act of 1980 (RFA) [214] generally requires a description and analysis of proposed rules that will have significant economic impact on a substantial number of small entities. The RFA mandates consideration of regulatory alternatives that accomplish the stated objectives of a proposed rule and that minimize any significant economic impact on a substantial number of small entities. The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.[215] The SBA recently revised its size standard for electric utilities (effective January 22, 2014) to a standard based on the number of employees, including affiliates (from a standard based on megawatt hours).[216] Under SBA's new size standards, electric utilities, electric power distribution, and electric bulk power transmission and control, and power marketers likely come under one of the following categories and associated size thresholds: [217]

- Hydroelectric power generation, at 500 employees
- Fossil fuel electric power generation, at 750 employees
- Nuclear electric power generation, at 750 employees
- Other electric power generation (e.g., solar, wind, geothermal, biomass, and other), at 250 employees
- Electric bulk power transmission and control, at 500 employees
- Electric power distribution, at 1,000 employees.
- Wholesale Trade Agents and Brokers,[218] at 100 employees

195. Based on U.S. economic census data,[219] the approximate percentages of small firms in these categories vary from 24 percent to 99 percent. However, currently FERC does not have information on how the economic census data compares with the specific entities affected by this proposed rule using the new SBA definitions.[220] Regardless, FERC recognizes that the rule will likely impact small electric utilities, electric power distribution, electric bulk power transmission and control, and power marketers and estimates the economic impact on each entity below.

[210] *Regulations Implementing the National Environmental Policy Act of 1969,* Order No. 486, 52 FR 47,897 (Dec. 17, 1987), FERC Stats. & Regs., Regulations Preambles 1986–1990 ¶ 30,783 (1987).

[211] 18 CFR 380.4.

[212] 18 CFR 380.4(a)(2)(ii).

[213] 18 CFR 380.4(a)(15).

[214] 5 U.S.C. 601–612 (2012).

[215] 13 CFR 121.101 (2013).

[216] SBA Final Rule on ''Small Business Size Standards: Utilities,'' 78 FR 77343 (Dec. 23, 2013).

[217] 13 CFR 121.201, Sector 22, Utilities.

[218] The NAICS category 425120 (Wholesale Electronic Markets and Agents and Brokers, within Subsector 425) covers Power Marketers.

[219] Data and further information are available from SBA at *http://www.sba.gov/advocacy/849/12162.*

[220] For utilities in the SBA's subsector 221, the previous SBA definition stated that ''[a] firm is small if, including its affiliates, it is primarily engaged in the generation, transmission, and/or distribution of electric energy for sale and its total electric output for the preceding fiscal year did not exceed 4 million megawatt hours.'' Using the previous SBA definition and EQR data from Quarter 3 of 2012 through Quarter 2 of 2013, 678 of the 1,903 sellers with market-based rate authority potentially affected by the proposed rule would have qualified as small entities. For this estimate, power marketers are included with utilities.

196. The proposed rule will eliminate some requirements, streamline and clarify others, and add a few minimal requirements, while reducing burden on entities of all sizes (public utilities seeking and currently possessing market-based rate authority). Implementation of the proposed rule is expected to reduce total annual burden by 27 percent to the industry. However, the number of filings with the Commission will decrease only slightly because the only filings that are proposed to be eliminated are the Quarterly Land Acquisition Reports, which we estimate account for four percent of the total annual burden on the industry.

197. As discussed in Order No. 697,[221] current regulations regarding market-based rate sellers under Subpart H to Part 35 of Title 18 of the Code of Federal Regulations exempt many small entities (using SBA's former definition of a small entity not exceeding 4 million megawatt hours) from significant filing requirements by designating them as Category 1 sellers.[222] Category 1 sellers are exempt from triennial updates and may use simplifying assumptions, such as assuming no competing imports, that the Commission allows sellers to use in submitting their horizontal market power analysis.

198. No longer requiring RTO sellers to file indicative screens will reduce the burden on all sellers in RTOs, including small entities in RTOs. The proposed rule also serves to clarify existing requirements, such as clarifying that sellers with fully-committed generation may submit an explanation that their generation is fully committed in lieu of submitting indicative screens. Such clarification may be particularly helpful to small entities as many small entities have fully-committed generation.

199. By adopting a reporting threshold of a 100 MW cumulative change in generation capacity for reporting changes in status regarding new affiliations, the Commission expects a reduction in the frequency of notice of change in status filings, which will necessarily reduce the burden on market-based rate sellers, including small entities.

200. The Commission is proposing to discontinue the land acquisition reporting requirements, which eliminates the need to submit such filings altogether. By so doing, the reduction in burden will be across all market-based rate sellers, including small entities.

201. The additional one-time burden to market-based rate sellers is expected to cause a minimal increase in burden only during initial implementation, and will decrease future burdens by allowing a streamlined analysis in subsequent filings. The additional ongoing requirements (such as providing organization charts, providing details on the components in Appendix A within and outside the study area, and reporting non-affiliate long-term reservations and wheel-through transactions in Submittal 2) represent information that is already available to filers and should result in little additional burden.

202. The changes to the Commission's regulations for market-based rate sellers are estimated to cause a reduction of 27 percent in total annual burden to all sellers, including small entities.

203. Accordingly, the Commission certifies that the revised requirements set forth in this NOPR will not have a significant economic impact on a substantial number of small entities, and no regulatory flexibility analysis is required. The Commission finds that the regulations adopted here should not have a significant impact on small businesses.

VII. Comment Procedures

204. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due September 23, 2014. Comments must refer to Docket No. RM14–14–000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

205. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's Web site at *http://www.ferc.gov.* The Commission accepts most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

206. Commenters that are not able to file comments electronically must send an original of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE., Washington, DC 20426.

207. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

VIII. Document Availability

208. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (*http://www.ferc.gov*) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street NE., Room 2A, Washington, DC 20426.

209. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

210. User assistance is available for eLibrary and the Commission's Web site during normal business hours from the Commission's Online Support at 202–502–6652 (toll free at 1–866–208–3676) or email at *ferconlinesupport@ferc.gov,* or the Public Reference Room at (202) 502–8371, TTY (202) 502–8659. Email the Public Reference Room at *public.referenceroom@ferc.gov.*

List of Subjects in 18 CFR Part 35

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

By direction of the Commission.

Issued: June 19, 2014.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

In consideration of the foregoing, the Commission proposes to amend part 35, Chapter I, Title 18, *Code of Federal Regulations,* as follows:

PART 35—FILING OF RATE SCHEDULES AND TARIFFS

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

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

■ 2. Amend § 35.36 by revising paragraph (a)(2) to read as follows:

[221] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at PP 1126–1129.

[222] Category 1 Sellers are power marketers and power producers that own or control 500 MW or less of generating capacity in aggregate and that are not affiliated with a public utility with a franchised service territory. In addition, Category 1 sellers must not own or control transmission facilities, and must present no other vertical market power issues. 18 CFR 35.36(a)(2).

§ 35.36 Generally.

(a) * * *

(2) *A Category 1 Seller* means a Seller that:

(i) Is either a wholesale power marketer that controls or is affiliated with 500 MW or less of generation in aggregate per region or a wholesale power producer that owns, controls or is affiliated with 500 MW or less of generation in aggregate in the same region as its generation assets;

(ii) Does not own, operate or control transmission facilities other than limited equipment necessary to connect individual generating facilities to the transmission grid (or has been granted waiver of the requirements of Order No. 888, FERC Stats. & Regs. ¶ 31,036);

(iii) Is not affiliated with anyone that owns, operates or controls transmission facilities in the same region as the Seller's generation assets;

(iv) Is not affiliated with a franchised public utility in the same region as the Seller's generation assets; and

(v) Does not raise other vertical market power issues.

* * * * *

■ 3. Amend § 35.37 as follows:

■ a. In paragraph (a)(1), remove the phrase ''contained in Order No. 697, FERC Stats. & Regs. ¶ 31,252'' and add in its place ''posted on the Commission's Web site.''

■ b. Revise paragraphs (a)(2) and (c)(4).

■ c. Add paragraphs (c)C(5) and (c)(6).

■ d. Remove paragraph (e)(2) and redesignate paragraphs (e)(3) and (4) as paragraphs (e)(2) and (3), respectively.

■ e. Revise newly redesignated paragraph (e)(3).

The revisions and additions read as follows:

§ 35.37 Market Power analysis required.

(a)(1) * * *

(2) When submitting a market power analysis, whether as part of an initial application or an update, a Seller must include an appendix of assets, in the form provided in Appendix B of this subpart, and an organizational chart. The organizational chart must depict the Seller's current corporate structure indicating all upstream owners, energy subsidiaries and energy affiliates.

* * * * *

(c) * * *

(4) When submitting the indicative screens, a Seller must use the format provided in Appendix A of this subpart and file the indicative screens in an electronic spreadsheet format. A Seller must include all supporting materials referenced in the indicative screens.

(5) Sellers submitting simultaneous transmission import limit studies must file Submittal 1, and, if applicable, Submittal 2, in the electronic spreadsheet format provided on the Commission's Web site.

(6) In lieu of submitting the indicative screens, Sellers in regional transmission organization and independent system operator markets with Commission-approved market monitoring and mitigation must include a statement that they are relying on such mitigation to address any potential horizontal market power concerns.

* * * * *

(e) * * *

(3) A Seller must ensure that this information is included in the record of each new application for market-based rates and each updated market power analysis. In addition, a Seller is required to make an affirmative statement that it and its affiliates have not erected barriers to entry into the relevant market and will not erect barriers to entry into the relevant market.

* * * * *

■ 4. Amend § 35.42 as follows:

■ a. Revise paragraphs (a)(1), (a)(2), and (c).

■ b. In paragraph (b), remove the phrase '', other than a change in status submitted to report the acquisition of control of a site or sites for new generation capacity development,''.

■ c. Remove paragraphs (d) and (e).

The revisions read as follows:

§ 35.42 Change in status reporting requirement.

(a) * * *

(1) Ownership or control of generation capacity or long-term firm purchases of capacity and/or energy that results in cumulative net increases (i.e., the difference between increases and decreases in affiliated generation capacity) of 100 MW or more of nameplate capacity in any relevant geographic market (including generation in the relevant geographic market and generation in any markets that are first tier to the relevant geographic market), or of inputs to electric power production, or ownership, operation or control of transmission facilities, or

(2) Affiliation with any entity not disclosed in the application for market-based rate authority that:

(i) Owns or controls generation facilities or has long-term firm purchases of capacity and/or energy that results in cumulative net increases (i.e., the difference between increases and decreases in affiliated generation capacity) of 100 MW or more of nameplate capacity in any relevant geographic market (including generation in the relevant geographic market(s) and generation in any markets that are first tier to the relevant geographic market(s));

(ii) Owns or controls inputs to electric power production;

(iii) Owns, operates or controls transmission facilities; or

(iv) Has a franchised service area.

* * * * *

(c) When submitting a change in status notification regarding a change that impacts the pertinent assets held by a Seller or its affiliates with market-based rate authorization, a Seller must include an appendix of all assets, including the new assets and/or affiliates reported in the change in status, in the form provided in Appendix B of this subpart, and an organizational chart. The organizational chart must depict the Seller's prior and new corporate structures indicating all upstream owners, energy subsidiaries and energy affiliates unless the Seller demonstrates that the change in status does not affect the corporate structure of the Seller's affiliations.

BILLING CODE: 6717–01–P

■ 5. Appendix A of subpart H is revised to read as follows:

Appendix A: Standard Screen Format (Data provided for illustrative purposes only)
Part I – Pivotal Supplier Analysis

Applicant-> Company X, LLC (TO)
Market -> Company X BAA
Date of Filing -> 0-Jan-00

Don't Enter Values (Outlined cell)

Row			Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	1,500	worksheet X
A1	Remote Capacity (from outside the study area)	200	worksheet X
B	Long-Term Firm Purchases (from inside the study area)	70	worksheet X
B1	Long-Term Firm Purchases (from outside the study area)	200	worksheet X
C	Long-Term Firm Sales (in and outside the study area)	(500)	worksheet X
D	Uncommitted Capacity Imports	0	worksheet X
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	300	worksheet X
E1	Remote Capacity (from outside the study area)	50	worksheet X
F	Long-Term Firm Purchases (from inside the study area)	40	worksheet X
F1	Long-Term Firm Purchases (from outside the study area)	40	worksheet X
G	Long-Term Firm Sales (in and outside the study area)	(60)	worksheet X
H	Uncommitted Capacity Imports	2,500	worksheet X
I	Study Area Reserve Requirement	(300)	worksheet X
J	Amount of Line I Attributable to Seller, if any	(200)	
K	Total Uncommitted Supply (Sum A,A1,B,B1,C,D,E,E1,F,F1,G,H,I,M)	2,840	
	Load		
L	Balancing Authority Area Annual Peak Load	1,500	worksheet X
M	Average Daily Peak Native Load in Peak Month	(1,200)	worksheet X
N	Amount of Line M Attributable to Seller, if any	(900)	worksheet X
O	Wholesale Load (SUM L,M)	300	
P	Net Uncommitted Supply (K-O)	2,540	
Q	Seller's Uncommitted Capacity (Sum A,A1,B,B1,C,D,J,N)	370	

Result of Pivotal Supplier Screen (Pass if Line Q < Line P) **Pass**
(Fail if Line Q > Line P)

Total Imports (Sum D,H), as filed by Seller ->	2,500
% of SIL for Seller's imported capacity ->	0.00
% of SIL for Other's imported capacity ->	1.00
SIL value* ->	2,500
Do Total Imports exceed the SIL value? ->	No

* Transmission owners filing triennials should use the SIL values from their Submittal 1, Row 10 (*see Puget Sound Energy, Inc.*, 135 FERC ¶ 61,254 (2011)). Other sellers should use Commission-accepted SIL values, if they exist for the study area and study period. If these values do not exist, sellers should use SIL values that have been filed but not accepted.

Appendix A: Standard Screen Format (Data provided for illustrative purposes only)
Part II – Market Share Analysis

Applicant-> Company X, LLC (TO)
Study Area -> Company X BAA
Data Year -> Don't Enter Values (Outlined cell)

As filed by the Applicant/Seller

Row		Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled or under LT contract)					
A	Installed Capacity (inside the study area)	1,000	900	1,500	1,000	worksheet X
A1	Remote Capacity (from outside the study area)	400	300	200	200	worksheet X
B	Long-Term Firm Purchases (inside the study area)	60	40	70	30	worksheet X
B1	Long-Term Firm Purchases (from outside the study area)	200	200	200	200	worksheet X
C	Long-Term Firm Sales (in and outside the study area)	(500)	(500)	(500)	(500)	worksheet X
D	Seasonal Average Planned Outages	(150)	(50)	(80)	(100)	worksheet X
E	Uncommitted Capacity Imports	0	0	0	0	worksheet X
	Capacity Deductions					
F	Average Peak Native Load in the Season	(1,000)	(900)	(1,200)	(800)	worksheet X
G	Amount of Line F Attributable to Seller, if any	(700)	(700)	(900)	(600)	worksheet X
H	Amount of Line F Attributable to Non-Affiliates, if any	(300)	(200)	(300)	(200)	
I	Study Area Reserve Requirement	(200)	(200)	(300)	(100)	worksheet X
J	Amount of Line I Attributable to Seller, if any	(100)	(100)	(200)	(80)	worksheet X
K	Amount of Line I Attributable to Non-Affiliates, if any	(100)	(100)	(100)	(20)	
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	250	200	300	150	worksheet X
L1	Remote Capacity (from outside the study area)	50	50	50	50	worksheet X
M	Long-Term Firm Purchases (inside the study area)	30	30	30	30	worksheet X
M1	Long-Term Firm Purchases (from outside the study area)	40	30	40	20	worksheet X
N	Long-Term Firm Sales (in and outside the study area)	(50)	(30)	(60)	(50)	worksheet X
O	Seasonal Average Planned Outages	(10)	(20)	(10)	(20)	worksheet X
P	Uncommitted Capacity Imports	2,000	1,500	2,500	1,300	worksheet X
	Supply Calculation					
Q	Total Competing Supply (Sum H, K, L,L1,M,M1,N,O,P)	1,910	1,460	2,450	1,260	
R	Seller's Uncommitted Capacity (Sum A,A1,B,B1,C,D,E,G,J)	210	90	290	150	
S	Total Seasonal Uncommitted Capacity (Sum Q,R)	2,120	1,550	2,740	1,410	
T	**Seller's Market Share** (R/S)	9.9%	5.8%	10.6%	10.6%	
	Results (Pass if < 20% and Fail if ≥ 20%)	Pass	Pass	Pass	Pass	
U	Total Imports, as filed by Seller (Sum E,P)	2,000	1,500	2,500	1,300	
V	SIL value*	2,000	1,500	2,500	1,300	
	Do Total Imports exceed SIL value? (is U<=V)	No	No	No	No	

* Transmission owners filing triennials should use the SIL values from their Submittal 1, Row 10 (*see Puget Sound Energy, Inc.*, 135 FERC ¶ 61,254 (2011)). Other sellers should use Commission-accepted SIL values, if they exist for the study area and study period. If these values do not exist, sellers should use SIL values that have been filed but not accepted.

■ 6. Appendix B of subpart H is revised to read as follows:

Appendix B:

Market-Based Rate Authority and Generation Assets

This is an example of the required appendix listing the filing entity and all its energy affiliates and their associated assets which should be submitted with all market-based rate filings.

Market-Based Rate Authority and Generation Assets

Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned By	Controlled By	Date Control Transferred	Location		In-Service Date	Capacity Rating (MW): Nameplate, Seasonal, or Five-Year Average
						Market / Balancing Authority Area	Geographic Region		

Electric Transmission Assets and/or Natural Gas Intrastate Pipelines and/or Gas Storage Facilities

Filing Entity and its Energy Affiliates	Cite to order accepting OATT or granting OATT waiver	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size (length and kV)
						Market / Balancing Authority Area	Geographic Region	

Note: The following appendices will not be published in the Code of Federal Regulations.

Appendix C

Schedule for Transmission Owning Utilities with Market-based Rate Authority that are Designated as Category 2 Sellers in the Region

Entities Required to File	Study Period			Filing Period (anytime during this month)
Northeast Transmission Owning Utilities	December 2011	to	November 2012	December: 2013
Southeast Transmission Owning Utilities	December 2011	to	November 2012	June: 2014
Central Transmission Owning Utilities	December 2012	to	November 2013	December: 2014
SPP Transmission Owning Utilities	December 2012	to	November 2013	June: 2015
Southwest Transmission Owning Utilities	December 2013	to	November 2014	December: 2015
Northwest Transmission Owning Utilities	December 2013	to	November 2014	June: 2016
Northeast Transmission Owning Utilities	December 2014	to	November 2015	December: 2016
Southeast Transmission Owning Utilities	December 2014	to	November 2015	June: 2017
Central Transmission Owning Utilities	December 2015	to	November 2016	December: 2017
SPP Transmission Owning Utilities	December 2015	to	November 2016	June: 2018
Southwest Transmission Owning Utilities	December 2016	to	November 2017	December: 2018
Northwest Transmission Owning Utilities	December 2016	to	November 2017	June: 2019
Northeast Transmission Owning Utilities	December 2017	to	November 2018	December: 2019
Southeast Transmission Owning Utilities	December 2017	to	November 2018	June: 2020
Central Transmission Owning Utilities	December 2018	to	November 2019	December: 2020
SPP Transmission Owning Utilities	December 2018	to	November 2019	June: 2021
Southwest Transmission Owning Utilities	December 2019	to	November 2020	December: 2021
Northwest Transmission Owning Utilities	December 2019	to	November 2020	June: 2022
Northeast Transmission Owning Utilities	December 2020	to	November 2021	December: 2022
Southeast Transmission Owning Utilities	December 2020	to	November 2021	June: 2023
Central Transmission Owning Utilities	December 2021	to	November 2022	December: 2023
SPP Transmission Owning Utilities	December 2021	to	November 2022	June: 2024
Southwest Transmission Owning Utilities	December 2022	to	November 2023	December: 2024
Northwest Transmission Owning Utilities	December 2022	to	November 2023	June: 2025

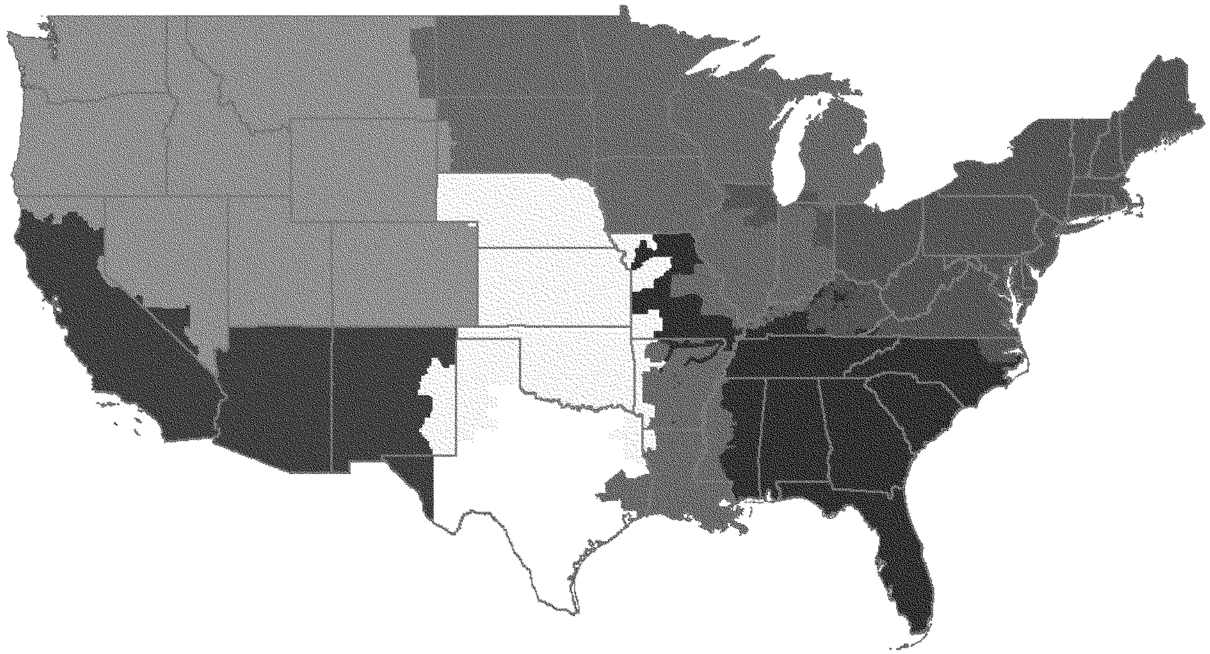
Appendix C1

Schedule for Non-Transmission Owning Utilities with Market-based Rate Authority that are Designated as Category 2 Sellers in the Region

Entities Required to File		Study Period					Filing Period (anytime during this month)
Northwest	Non-Transmission Owning Utilities	December	2010	to	November	2011	December: 2013
Northeast	Non-Transmission Owning Utilities	December	2011	to	November	2012	June: 2014
Southeast	Non-Transmission Owning Utilities	December	2011	to	November	2012	December: 2014
Central	Non-Transmission Owning Utilities	December	2012	to	November	2013	June: 2015
SPP	Non-Transmission Owning Utilities	December	2012	to	November	2013	December: 2015
Southwest	Non-Transmission Owning Utilities	December	2013	to	November	2014	June: 2016
Northwest	Non-Transmission Owning Utilities	December	2013	to	November	2014	December: 2016
Northeast	Non-Transmission Owning Utilities	December	2014	to	November	2015	June: 2017
Southeast	Non-Transmission Owning Utilities	December	2014	to	November	2015	December: 2017
Central	Non-Transmission Owning Utilities	December	2015	to	November	2016	June: 2018
SPP	Non-Transmission Owning Utilities	December	2015	to	November	2016	December: 2018
Southwest	Non-Transmission Owning Utilities	December	2016	to	November	2017	June: 2019
Northwest	Non-Transmission Owning Utilities	December	2016	to	November	2017	December: 2019
Northeast	Non-Transmission Owning Utilities	December	2017	to	November	2018	June: 2020
Southeast	Non-Transmission Owning Utilities	December	2017	to	November	2018	December: 2020
Central	Non-Transmission Owning Utilities	December	2018	to	November	2019	June: 2021
SPP	Non-Transmission Owning Utilities	December	2018	to	November	2019	December: 2021
Southwest	Non-Transmission Owning Utilities	December	2019	to	November	2020	June: 2022
Northwest	Non-Transmission Owning Utilities	December	2019	to	November	2020	December: 2022
Northeast	Non-Transmission Owning Utilities	December	2020	to	November	2021	June: 2023
Southeast	Non-Transmission Owning Utilities	December	2020	to	November	2021	December: 2023
Central	Non-Transmission Owning Utilities	December	2021	to	November	2022	June: 2024
SPP	Non-Transmission Owning Utilities	December	2021	to	November	2022	December: 2024
Southwest	Non-Transmission Owning Utilities	December	2022	to	November	2023	June: 2025

Appendix D

Generalized Map of Geographic Regions



Northeast (ISO-NE, NYISO, PJM)

Southeast (SERC and FRCC NERC Regions, excluding for PJM and MISO members)

Central (Midcontinent Independent System Operator (MISO) and members of the Midwest Reliability Organization (MRO) that are not part of another RTO)

Southwest Power Pool (SPP NERC Region, excluding MISO members)

Southwest (Arizona, most of California, part of Nevada and the portions of New Mexico and Texas within the Western Interconnection)

Northwest (The remainder of the Western Interconnection)

Appendix E

Submittal 1: Summary Table of the Components Used to Calculate SIL Values

Table 1: SIL Computation

Study Period: December 1, 20XX to November 30, 20XX

		Name of Home BAA/Market				Name of First-Tier BAA			
		Winter	**Spring**	**Summer**	**Fall**	**Winter**	**Spring**	**Summer**	**Fall**
Row	**Description of Component**	**(MW)**	**(MW)**	**(MW)**	**(MW)**	**(MW)**	**(MW)**	**(MW)**	**(MW)**
1	**Simultaneous Incremental Transfer Capability** The most limiting First Contingency Incremental Transfer Capability (FCITC), Normal Incremental Transfer Capability (NITC) or equivalent values. *Note i*	1,700	1,800	1,900	2,000	3,000	3,200	3,400	3,600
2	**Modeled Net Area Interchange** (NAI) Enter a positive value and indicate the direction of flow in row 3 below. *Note ii*	500	600	700	800	200	300	400	500
3	**Interchange Direction** Indicate whether the Study Area NAI is export or import.	Import	Import	Import	Import	Export	Export	Export	Export
4	**Total Simultaneous Transfer Capability** (row 4 = row 1 +/- row 2). *Note iii*	2,200	2,400	2,600	2,800	2,800	2,900	3,000	3,100
5	**Long-Term Firm Transmission Reservations** Sum of the long-term firm transmission reservations from Table 2. *Note iv*	620	300	620	300	460	360	460	360
6	**Calculated SIL Value** (row 6 = row 4 - row 5). *Note v*	1,580	2,100	1,980	2,500	2,340	2,540	2,540	2,740
7	**Historical Peak Load** (Identify source if not from FERC Form No. 714). *Note vi*	1,400	1,900	2,500	2,000	1,400	1,900	2,500	2,000
8	**Adjusted Historical Peak Load** (row 8 = row 7 - row 5). *Note vii*	780	1,600	1,880	1,700	940	1,540	2,040	1,640
9	**Uncommitted First-Tier Generation** Amount of uncommitted generation modeled in the first-tier area. *Note viii*	13,580	12,800	14,500	12,800	13,580	12,800	14,500	12,800
10	**SIL Study Value** (row 10 = the minimum of the values entered in rows 6, 8 and 9 for each season). Use these SIL Study Values in the Market Share Screens. *Note ix*	780	1,600	1,880	1,700	940	1,540	2,040	1,640

Submittal 2: Identify Long-Term Firm Transmission Reservations Used to Import Power from Generating Resources in the First-Tier Area to Serve Native Load in the Study Area

Table 2: Long-Term Firm Transmission Reservations

		Name of Home BAA/Market				Name of First-Tier BAA			
	Description of Remote Resource	**Winter (MW)**	**Spring (MW)**	**Summer (MW)**	**Fall (MW)**	**Winter (MW)**	**Spring (MW)**	**Summer (MW)**	**Fall (MW)**
	Affiliates								
1	MW Share of Remote Plant #1	100	-	100	-	50	50	50	50
2	MW Share of Remote Plant #2	50	50	50	50	100	-	100	-
3	MW Share of Remote Plant #3	60	-	60	-	-	50	-	50
4	Purchased Power Agreement where the energy is imported into the study area with long-term firm reservations	100	100	100	100	80	80	80	80
5	Wheel through transactions to serve first-tier area load embedded in the study area using first-tier generation								
6	Sum of affiliated long-term firm reservations	310	150	310	150	230	180	230	180
	Non-Affiliates								
7	MW Share of Remote Plant #1	100	-	100	-	50	50	50	50
8	MW Share of Remote Plant #2	50	50	50	50	100	-	100	-
9	MW Share of Remote Plant #3	60	-	60	-	-	50	-	50
10	Purchased Power Agreement where the energy is imported into the study area with long-term firm reservations	100	100	100	100	80	80	80	80
11	Wheel through transactions to serve first-tier area load embedded in the study area using first-tier generation								
12	Sum of non-affiliated long-term firm reservations	310	150	310	150	230	180	230	180
13	Sum of affiliated and non-affiliated long-term firm reservations (enter value in row 5 of Table 1 above)	620	300	620	300	460	360	460	360

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