Description: Notice of Self-Certification of Exempt Wholesale Generator Status of Seville Solar Two, LLC.
Filed Date: 10/8/15.
Accession Number: 20151008–5087.
Comments Due: 5 p.m. ET 10/29/15.

Take notice that the Commission received the following electric rate filings:

Docket Numbers: ER10–2331–040; ER14–630–017; ER10–2319–032; ER10–2317–032; ER13–1351–014; ER10–2330–039.
Applicants: J.P. Morgan Ventures Energy Corporation, AlphaGen Power LLC, BE Alabama LLC, BE CA LLC, Florida Power Development LLC, Utility Contract Funding, L.L.C.
Description: Notice of Non-Material Change in Status of the J.P. Morgan Sellers.
Filed Date: 10/7/15.
Accession Number: 20151007–5156.
Comments Due: 5 p.m. ET 10/28/15.

Docket Numbers: ER11–4380–005; ER13–1562–004; ER13–1641–002; ER10–2434–006; ER10–2467–006; ER10–2488–012; ER12–1931–006; ER15–1045–001;ER10–2504–007; ER12–610–007; ER13–338–006;ER12–2037–006; ER12–2314–005; ER10–2436–006;ER11–4381–005.
Applicants: Bellevue Solar, LLC, Catalina Solar Lessee, LLC, Chestnut Flats Lessee, LLC, Fenton Power Partners I, LLC, Hoosier Wind Project, LLC, Oasis Power Partners, LLC, Pacific Wind Lessee, LLC, Pilot Hill Wind, LLC, Shiloh Wind Project 2, LLC, Shiloh III Lessee, LLC, Shiloh IV Lessee, LLC, Spearville 3, LLC, Spinning Spur Wind LLC, Wapsipinicon Wind Project, LLC, Yamhill Solar, LLC.
Description: Notice of Change in Status of the EDF–RE MBR Companies.
Filed Date: 10/7/15.
Accession Number: 20151007–5249.
Comments Due: 5 p.m. ET 10/28/15.

Docket Numbers: ER15–2426–000.
Applicants: Northern Indiana Public Service Company.
Description: Amendment to August 12, 2015 Proposed Reactive Power Revenue Requirements of Northern Indiana Public Service Company for twelve generating facilities located in the MISO pricing zone under ER15–2426.
Filed Date: 10/7/15.
Accession Number: 20151007–5243.
Comments Due: 5 p.m. ET 10/13/15.

Docket Numbers: ER16–34–000.
Applicants: Harborside Energy, LLC.
Description: Baseline eTariff Filing: Market Based Rate Tariff to be effective 11/5/2015.
Filed Date: 10/8/15.
Accession Number: 20151008–5001.
Comments Due: 5 p.m. ET 10/29/15.

Docket Numbers: ER16–35–000.
Applicants: Brown's Energy Services, LLC.
Description: Baseline eTariff Filing: Market Based Rate Tariff to be effective 11/5/2015.
Filed Date: 10/8/15.
Accession Number: 20151008–5002.
Comments Due: 5 p.m. ET 10/29/15.

The filings are accessible in the Commission's eLibrary system by clicking on the links or querying the docket number.

Any person desiring to intervene or protest in any of the above proceedings must file in accordance with Rules 211 and 214 of the Commission's Regulations (18 CFR 385.211 and 385.214) on or before 5:00 p.m. Eastern time on the specified comment date. Protests may be considered, but intervention is necessary to become a party to the proceeding.

eFiling is encouraged. More detailed information relating to filing requirements, interventions, protests, service, and qualifying facilities filings can be found at: *http://www.ferc.gov/docs-filing/efiling/filing-req.pdf.* For other information, call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Dated: October 8, 2015.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2015–26701 Filed 10–20–15; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. ER10–2302–005]

Before Commissioners: Norman C. Bay, Chairman; Philip D. Moeller, Cheryl A. LaFleur, Tony Clark, and Colette D. Honorable; Public Service Company of New Mexico, Order Accepting Notice of Change in Status, Rejecting, Without Prejudice, Request for Market-Based Rate Authorization and Providing Clarification on Submitting Delivered Price Test Analyses and Simultaneous Transmission Import Limit Studies

1. In this order, we accept the notice of change in status filed by Public Service Company of New Mexico (PNM) to report a transaction in which it purchased the interests in Delta Person, Limited Partnership (Delta Person).[1] Also in this order, we reject, without prejudice, PNM's request for market-based rate authority in the PNM balancing authority area and we reject, without prejudice, the simultaneous transmission import limit (SIL) values submitted by PNM for the PNM balancing authority area. We take this opportunity to remind applicants seeking initial market-based rate authority or seeking to retain such authority of the type of information and analysis that is useful and appropriate for our consideration of a Delivered Price Test (DPT) and what is not. We are providing this information not only to PNM but to industry broadly with respect to several issues that arose in our review of the DPT analysis and SIL study prepared by PNM. These issues, as with others, are recurring across a myriad of applicants. Our goal in providing this clarification is to promote compliance with the Commission's regulations and policies in an effort to more timely process requests for market-based rate authorization and reduce delay.

I. Background

2. On August 18, 2014, as amended on December 17, 2014 and February 18, 2015,[2] PNM filed a notice of change in status notifying the Commission that, effective July 17, 2014, PNM purchased the interests in Delta Person, the owner of a 132 megawatt (MW) gas-fired generating facility located in the PNM balancing authority area. PNM states that the acquisition does not affect PNM's horizontal market power because, prior to the acquisition, PNM purchased the full output of the facility under a long-term contract with Delta Person and, as such, was already deemed to control the output of that facility.[3]

3. Additionally, PNM requests market-based rate authorization in the PNM balancing authority area.[4] PNM states that the market characteristics in the PNM balancing authority area have changed since PNM relinquished its market-based rate authority in 2010 and PNM is therefore seeking to reestablish

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[1] The related acquisition of jurisdictional facilities was authorized by the Commission in *Delta Person, Limited Partnership,* 142 FERC ¶ 62,155 (2013).

[2] For purposes of this order, the February 18, 2015 amendment will be referred to as ''Response to the Data Request.''

[3] August 18, 2014 Filing at 1.

[4] PNM states that its tariff reflects that it relinquished its market-based rate authority in the PNM and El Paso Electric Company (El Paso Electric) balancing authority areas. *Id.* at 3 (citing *Public Service Company of New Mexico,* Docket No. ER96–1551–022 (Oct. 26, 2010) (delegated letter order)). PNM states that it only seeks to reestablish its market-based rate authority in the PNM balancing authority area and not in the El Paso Electric balancing authority area. *Id.* at 2 n.4.

its market-based rate authority in that balancing authority area.[5]

4. PNM included an updated market power analysis with its August 18, 2014 Filing. PNM states that it passes the pivotal supplier screen and the wholesale market share screen in the summer season; however, PNM represents that it fails the wholesale market share screen in the winter, fall, and spring seasons. PNM notes that the failure of the indicative screens creates a rebuttable presumption of horizontal market power. However, PNM states it has rebutted that presumption by demonstrating that PNM passes a DPT analysis for the PNM balancing authority area.[6]

5. Additionally, PNM submitted historical evidence related to a request for proposal (RFP) issued by the City of Gallup, New Mexico, representing that PNM was not selected as the winner and that the results of the RFP should be considered as alternative evidence to rebut the presumption that PNM may have market power in the PNM balancing authority area.[7]

6. On December 19, 2014, the Director of the Division of Electric Power Regulation—West requested additional information from PNM with regard to the DPT analysis and SIL study (Data Request).[8] On February 18, 2015, PNM submitted a revised DPT analysis and an additional SIL sensitivity analysis, with revised Submittal 1 and Submittal 2 results, in response to the request for additional information (Response to the Data Request).

II. Notice of Filings

7. Notice of PNM's August 18, 2014 filing, as amended on December 17, 2014 and on February 18, 2015, was published in the **Federal Register**,[9] with interventions and protests due on or before March 11, 2015. Navopache Electric Cooperative, Inc. (Navopache) filed a timely motion to intervene.

III. Discussion

A. Procedural Matters

8. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 CFR 385.214 (2015), Navopache's timely, unopposed motion to intervene serves to make it a party to this proceeding.

B. Substantive Matters

9. We accept PNM's notice of change in status filing. However, as discussed below, we reject, without prejudice, PNM's request for market-based rate authority in the PNM balancing authority area and PNM's related SIL study. We find that PNM has failed to rebut the presumption of horizontal market power in the PNM balancing authority area, and therefore, has not supported its request for market-based rate authority in the PNM balancing authority area. Also, as discussed below, we take this opportunity to identify deficiencies in PNM's DPT analysis and provide general clarification regarding DPT analyses and SIL studies. We note that our efforts to provide such clarification in this order are hampered by the fact that PNM's most recent February 18, 2015 DPT analysis and SIL submittals were all filed as non-public.[10] Thus, we often cite to earlier public versions of filings instead of the most recent non-public versions. However, unless otherwise noted, the discussion is applicable to the most recent non-public version as well.

C. Market-Based Rate Authorization

10. The Commission allows power sales at market-based rates if the seller and its affiliates do not have, or have adequately mitigated, horizontal and vertical market power.[11] An applicant that fails one or more of the indicative screens is provided with several procedural options including the right to challenge the market power presumption by submitting a DPT analysis.[12] As discussed in the body of this order, PNM's DPT analysis includes inaccurate data and modeling errors and is inconsistent with the Commission's regulations. The deficiencies pertain to the following: (i) Data integrity; (ii) identification of potential supply; (iii) calculation of variable costs; (iv) accounting for power purchase agreements; (v) calculation of transmission rates; (vi) calculation of available economic capacity (AEC); (vii) use of historical transaction data to corroborate results; and (viii) preparation of the SIL study.

1. Horizontal Market Power

11. The Commission adopted two indicative screens for assessing horizontal market power: the pivotal supplier screen and the wholesale market share screen.[13] The Commission has stated that passage of both screens establishes a rebuttable presumption that the applicant does not possess horizontal market power, while failure of either screen creates a rebuttable presumption that the applicant has horizontal market power.[14]

12. PNM prepared the pivotal supplier and wholesale market share screens for the PNM balancing authority area, consistent with the requirements of Order No. 697.[15] We have reviewed these and find that PNM passes the pivotal supplier screen and the wholesale market share screen in the summer season with a market share of 18.0 percent, but fails the wholesale market share screen in the other seasons with market shares ranging from 24.9 to 26.8 percent.[16] As a result of failing the indicative screens in the fall, winter, and spring seasons, PNM submitted alternative evidence and performed a DPT analysis to rebut the presumption of horizontal market power in the PNM balancing authority area.

13. As the Commission has previously explained, the DPT analysis identifies potential suppliers based on market prices, input costs, and transmission availability, and calculates each supplier's economic capacity (EC)[17] and

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[5] *Id.* at 4.

[6] On December 17, 2014, PNM submitted public versions of its DPT files, explaining that it initially submitted numerous electronic files related to the DPT analysis on a confidential basis.

[7] *Id.* at 12–13.

[8] *Public Service Company of New Mexico,* Docket No. ER10–2302–005 (Dec. 19, 2014) (delegated letter order). We note that on January 21, 2015, PNM filed a motion for an extension of time to file its Response to the Data Request, which was granted. *See* Notice of Extension of Time, Docket No. ER10–2302–005 (Jan. 27, 2015).

[9] 79 FR 50,642; 79 FR 78,081 (2014); 80 FR 10,472 (2015).

[10] We encourage filers to submit as much information as possible as public and only to claim confidential treatment for information that is exempt from mandatory disclosure under the Freedom of Information Act, 5 U.S.C. 552. Filers must follow the requirements in 18 CFR 388.112 (2015) when submitting requests for privileged treatment of filings.

[11] *See Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities,* Order No. 697, FERC Stats. & Regs. ¶ 31,252, at PP 62, 399, 408, 440, *clarified,* 121 FERC ¶ 61,260 (2007), *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).

[12] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 63.

[13] *Id.* P 62.

[14] *Id.* PP 33, 62–63.

[15] *Id.* PP 231–232.

[16] August 18, 2014 Filing, Exhibit No. JMC–3.

[17] The EC of a supplier is defined as "the amount of generating capacity owned or controlled by a potential supplier with variable costs low enough that energy from such capacity could be economically delivered to the destination market." *See* 18 CFR 33.3(c)(4)(i)(A) (2015).

AEC[18] for each season/load period.[19] The results of the DPT can be used for pivotal supplier, market share and market concentration analyses.[20] Under the DPT analysis, applicants must also calculate market concentration using the Hirschman-Herfindahl Index (HHI).[21] An HHI of less than 2,500 in the relevant market for all seasons/load periods, in combination with a demonstration that the applicants are not pivotal and do not possess more than a 20 percent market share in any of the seasons/load periods, would constitute a showing of a lack of horizontal market power, absent compelling contrary evidence from interveners. A detailed description of the mechanics of the DPT analysis is provided in Order No. 697.[22]

14. As with the indicative screens, applicants and interveners may present evidence, such as historical sales and transmission data, which may be used to calculate market shares and market concentration and to refute or support the results of the DPT analysis. In Order No. 697, the Commission encouraged applicants to present the most complete analysis of competitive conditions in the market as the data allow.[23]

15. PNM's DPT analysis for the PNM balancing authority area indicates that PNM is not pivotal in any season/load period using either the EC measure or the AEC measure.[24] Using the AEC measure, PNM reports market shares below 20 percent in all seasons/load periods and HHIs below 2,500.[25] However, using the EC measure, PNM reports market shares above 20 percent in all seasons/load periods and HHIs below 2,500.[26]

a. Alternative Evidence—RFP

16. PNM states that the Commission allows a seller to present alternative evidence to rebut the results of the indicative screens. PNM requests that the RFP results be considered as additional alternative evidence to rebut the presumption that PNM may have market power in the PNM balancing authority area.

17. According to PNM, on September 26, 2013, the City of Gallup issued an RFP for long-term power supply and scheduling services for a minimum of five years. The RFP represents that the City of Gallup serves approximately 10,500 customers and averages approximately 215,000,000 kilowatt-hours (kWh) in annual sales provided from wholesale energy purchases of around 220,000,000 kWh bought from PNM and 15,000,000 kWh from Western Area Power Administration. PNM states that, as the City of Gallup's existing supplier, it responded to the RFP. PNM further states that the City of Gallup received bids from five suppliers. Further, PNM represents that it was not selected as the winner in the RFP and ranked third in the competitiveness of its bid. PNM states that Continental Divide Electric Cooperative was selected as the winning bidder, having submitted a bid that was significantly lower than those submitted by either PNM or the other bidders.

18. PNM contends that the fact that there were a number of bidders in the RFP, several of whose bids were lower than the bid submitted by PNM, in and of itself, demonstrates that PNM lacks market power in the PNM balancing authority area. PNM further states that this alternative evidence is bolstered by the fact that a neighboring utility that maintains market-based rate authority in the PNM balancing authority area also underbid PNM, making it difficult to justify the notion that PNM has market power. Moreover, PNM states that the RFP is significant recent real-world evidence that corroborates the results of its DPT analysis demonstrating that PNM lacks market power in the PNM balancing authority area.

Commission Determination

19. Although PNM presents this RFP as alternative evidence to rebut the results of the indicative screens, we find that this alternative evidence does not sufficiently demonstrate that PNM lacks market power in that balancing authority area. We do not believe that the City of Gallup's load is a sufficient proxy for the load PNM served during the study period.[27] Further, the results of the RFP may simply reflect that there are competitors to PNM that can provide a small amount of long-term power supply and scheduling services for a minimum of five years less expensively than PNM. However, the Commission's analysis of horizontal market power includes other factors, such as uncommitted capacity and system operating conditions during various levels of load in a relevant geographic market, none of which is addressed by PNM's alternative evidence. Thus, we are unable to conclude from the RFP evidence that PNM lacks horizontal market power in the PNM balancing authority area. Further, PNM does not provide historical sales or transmission data to rebut the results of the indicative screens.[28]

b. DPT Analysis

20. In Order No. 697, the Commission provided the option for a seller to submit a DPT analysis when that seller fails an indicative screen.[29]

21. The Commission, prior to Order No. 697, provided industry guidance concerning the DPT in the Merger Policy Statement.[30] The Commission provided an overview of the definition of the product market studied by the DPT analysis, and specifically stated that a key part ''in determining the size of the geographic market is to identify those suppliers that can compete to serve a given market or customer and how much of a competitive presence they are in the market. Alternative suppliers must be able to reach the market both economically and physically. There are two parts to this analysis. One is determining the economic capability of a supplier to reach a market. This is accomplished by a delivered price test. The second part

[18] The Commission's regulations provide that AEC ''means the amount of generating capacity meeting the definition of economic capacity less the amount of generating capacity needed to serve the potential supplier's native load commitments,'' 18 CFR 33.3(c)(4)(i)(B) (2015).

[19] The seasons/load periods are as follows: super-peak, peak, and off-peak, for winter, shoulder, and summer periods and an additional highest super-peak for the summer.

[20] *See AEP Power Marketing, Inc.,* 107 FERC ¶ 61,018, at PP 106–108 (April 14 Order), *order on reh'g,* 108 FERC ¶ 61,026 (2004).

[21] The HHI is the sum of the squared market shares. For example, in a market with five equal size firms, each would have a 20 percent market share. For that market, HHI = $(20)^2 + (20)^2 + (20)^2 + (20)^2 + (20)^2$ = 400 + 400 + 400 + 400 + 400 = 2,000.

[22] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at PP 104–117.

[23] *Id.* PP 71, 111.

[24] August 18, 2014 Filing, Carey Aff. at 27, Table 4 (Delivered Price Test for the PNM BAA Destination Market Available Economic Capacity); *Id.,* Carey Aff. at 30, Table 5 (Delivered Price Test for the PNM BAA Destination Market Economic Capacity). We note that PNM also submitted sensitivity analyses that separately analyzed what effect, if any, a 10 percent increase or decrease in market price would have on the results of its DPT analysis. *Id.,* Carey Aff. at 30.

[25] *Id.,* Carey Aff. at 27, Table 4.

[26] *Id.,* Carey Aff. at 30, Table 5.

[27] We note that the 215,000,000 kWh translates into approximately 25 MW of load at a 100 percent load factor (215,000,000 kWh ÷ 1,000 = 215,000 MWh; 215,000 MWh ÷ 8,760 hours in a year = 24.5 MW). A load factor of 60 percent would translate into approximately 41 MW of annual peak load. Either amount is significantly less than the 2,142 MW of retail requirements, wholesale load obligation plus off system sales that PNM served during the summer peak of 2013. *See id.,* Carey Aff. at 11. It is also less than the 2,563 MW PNM balancing authority annual peak load. *See id.,* Exhibit No. JMC–3 at 1.

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

[29] *Id.* P 105.

[30] *Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement,* Order No. 592, FERC Stats. & Regs. ¶ 31,044 (1996) (Merger Policy Statement), *reconsideration denied,* Order No. 592–A, 79 FERC ¶ 61,321 (1997).

evaluates the physical capability of a supplier to reach a market.''[31]

22. The first part of the product market analysis, that is, the calculation of all potential suppliers given the prevailing market price. The EC of a supplier is the amount of generating capacity owned or controlled by a potential supplier with variable costs low enough that energy from such capacity could be economically delivered to the destination market. The EC calculation can be described as follows.[32]

23. The first step in calculating a potential supplier's EC is to calculate the variable cost of each unit.[33] Commission regulations state that, at a minimum, these costs include variable operation and maintenance, including both fuel and non-fuel operation and maintenance, and environmental compliance. To the extent these costs are allocated among units at the same plant, allocation methods should be fully described.[34] Any generation capacity acquired under long-term firm purchase contracts (*i.e.,* contracts with a remaining commitment of more than one year) should be added to the potential supplier's generation capacity.[35] In addition, the regulations provide that ''other generating capacity may also be attributed to another supplier based on operational control criteria as deemed necessary, but the applicant must explain the reasons for doing so.'' [36] The variable cost for contractual capacity acquired, or attributed to another supplier, should be calculated in the same way as generation owned or under the direct control of the supplier. Commission regulations also require that specific information on long-term purchase and sale data be submitted.[37]

24. The second step is to add to the estimate of the unit's variable generation cost any and all applicable transmission costs that a supplier would incur to deliver the energy into the study area. Commission regulations state that these costs include the maximum transmission rate in a transmission provider's tariff as well as the estimated cost of supplying energy losses.[38] The costs of ancillary services incurred to deliver the competing energy into the study area should also be included.[39] These costs should be accumulated beginning at the source of the generation and ending where the generation sinks in the study area.[40]

25. The final step in calculating economically competitive capacity is to determine whether the computed generation cost of a unit is price competitive in the study area. The supplier should compare the computed cost of a generating unit (including all aforementioned generation, transmission, and other costs), to the computed market price plus five (5) percent in the study area.[41] Generation with a delivered cost that meets all of the above conditions is referred to as the EC of that unit.

26. The AEC of the units and all suppliers must also be calculated. AEC includes ''capacity from generating units that are not used to serve native load (or are contractually committed).'' [42] Accordingly, AEC is the amount of generating capacity meeting the definition of economic capacity less the amount of generating capacity needed to serve the potential supplier's native load commitments, where native load commitments are ''commitments to serve wholesale and retail power customers on whose behalf the potential supplier, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate its system to meet their reliable electricity needs.'' [43] Units that are contractually committed or needed to serve native load or meet reliable electricity needs are not available to compete in a DPT analysis.

27. Furthermore, as stated in the Merger Policy Statement, the presumption underlying the AEC measure is that the lowest running cost units are used to serve native load and other firm contractual obligations and would not be available for other sales.[44] Such units are not available to compete in the DPT analysis.

28. The second part of the analysis, evaluating whether generation with AEC can reach the study area, and the use of this information to compute market shares and concentration statistics, is discussed below.

29. Turning to PNM's calculation, we find that the analysis as presented is flawed and from it we are unable to conclude that PNM rebutted the presumption of PNM's horizontal market power in the PNM balancing authority area. The deficiencies pertain to the following: (i) Data integrity; (ii) identification of potential supply; (iii) calculation of variable costs; (iv) accounting for power purchase agreements; (v) calculation of transmission rates; (vi) calculation of AEC; (vii) use of historical transaction data to corroborate results; and (viii) preparation of the SIL study. Each of these items is discussed further below.

PNM's Calculation of Economic Capacity

i. Data Integrity

30. PNM submitted compact discs (CDs) that included its DPT model and underlying work papers with links to other data sources that are not available on its CDs. For instance, when opening some of the files on the CDs submitted on August 18, 2014 and on February 18, 2015, there is an error message that states ''There are links to data sources that cannot be updated.''

31. We remind applicants that including workable links to data sources in the spreadsheets enables the

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[31] *Id.* at 31,130.

[32] We note that these steps are not an exhaustive list to perform a DPT analysis; however, these steps are provided as an illustration to discuss PNM's DPT analysis.

[33] *Revised Filing Requirements Under Part 33 of the Commission's Regulations,* Order No. 642, FERC Stats. & Regs. ¶ 31,111, at 31,886 n.39 (2000), *order on reh'g,* Order No. 642–A, 94 FERC ¶ 61,289 (2001).

[34] 18 CFR 33.3(d)(2)(i) (2015).

[35] 18 CFR 33.3(c)(4)(i)(A) (2015) (specifying that the potential supplier's capacity is adjusted by subtracting capacity committed under long-term firm sales contracts and adding capacity acquired under long-term firm purchase contracts).

[36] *Id.*

[37] 18 CFR 33.3(d)(3) (2015) (''*Long-term purchase and sales data.* For each sale and purchase of capacity, the applicant must provide the following information: (i) Purchasing entity name; (ii) Selling entity name; (iii) Duration of the contract; (iv) Remaining contract term and any evergreen provisions; (v) Provisions regarding renewal of the contract; (vi) Priority or degree of interruptibility; (vii) FERC rate schedule number, if applicable; (viii) Quantity and price of capacity and/or energy purchased or sold under the contract; and (ix) Information on provisions of contracts which confer operational control over generation resources to the purchaser.'').

[38] 18 CFR 33.3(d)(5)(i) and 33.3(d)(5)(iii)(H) (2015).

[39] 18 CFR 33.3(c)(4) (2015) (''*Perform delivered price test.* For each destination market, the applicant must calculate the amount of relevant product a potential supplier could deliver to the destination market from owned or controlled capacity at a price, including applicable transmission prices, loss factors and *ancillary services costs,* that is no more than five (5) percent above the pre-transaction market clearing price in the destination market.'' (emphasis added)).

[40] Merger Policy Statement, FERC Stats. & Regs. ¶ 31,044 at 31,132 (''In contrast, a supplier that is three or four 'wheels' away from the same buyer may be an economic supplier if the *sum of the wheeling charges and the effect of losses* is less than the difference between the decremental cost of the buyer and the price at which the supplier is willing to sell.'' (emphasis added)).

[41] April 14 Order, 107 FERC ¶ 61,018 at Appendix F (''[D]etermine the suppliers that could sell into the destination market at a price less than or equal to 5% over the market price. That is, determine which generators have costs less than or equal to 1.05 times the market price.''); *id.,* Appendix F n.216 (''The costs include running costs, transmission charges, [operation and maintenance] and environmental adders.'').

[42] Merger Policy Statement, FERC Stats. & Regs. ¶ 31,044 at 31,132.

[43] 18 CFR 33.3(d)(4)(i) (2015).

[44] Merger Policy Statement, FERC Stats. & Regs. ¶ 31,044 at 31,132.

Commission to verify the accuracy of the data sources and to ensure the accuracy of the submitted DPT.

ii. Identification of Potential Supply

32. PNM appears to have included generating units that are no longer operational when it calculated EC. EC is the amount of generating capacity owned or controlled by a potential supplier with variable costs low enough that energy from such capacity could be economically delivered to the destination market. Including, for example, the San Onofre Nuclear Generating Station (San Onofre) as operational and reporting units 2 and 3 of this plant as having EC in all seasons of the DPT analysis is inconsistent with the definition of EC.[45] Thus, the output of generating facilities, such as San Onofre, that are not in operation during the seasons studied in a DPT analysis cannot feasibly be delivered to the destination market and should not be included in EC.

33. Similarly, PNM identifies many units as having their output committed under long-term power purchase contracts, but still considers the units to have EC in the model. For example, PNM identifies Whitewater Hill Wind Partners as having EC when Whitewater Hill Wind Partners has affirmed to the Commission that the output of its facility is fully committed to an unaffiliated third party.[46] An entity that does not own any uncommitted capacity or hold a long-term purchase contract should not be considered as a potential supplier of EC in a DPT analysis.[47] In addition, PNM did not provide the information for these contracts as required in 18 CFR 33.3(d)(3)(i).

34. Commission regulations require that a potential supplier's EC be adjusted by long-term firm contracts.[48] Units that are committed to unaffiliated entities under long-term firm contracts should be attributed to the purchasing entities rather than the owners of those facilities, and should potentially be included in EC only if the purchasing entity has EC. Thus, the inclusion of nonoperational units in the DPT analysis is inappropriate and the output of facilities that are committed under long-term firm contracts should be attributed to the purchasing entities and included as EC only if the purchasing entity has EC. The inclusion of generation from such units distorts the amount of EC in the DPT analysis. This raises additional concerns that the DPT results may be inaccurate and unreliable.

iii. Calculating Variable Costs

35. As mentioned above, Commission regulations state that for each generating plant or unit owned or controlled by each potential supplier in a DPT analysis, the applicant must also provide variable cost components, which must include at a minimum: (A) variable operation and maintenance, including both fuel and non-fuel operation and maintenance; and (B) environmental compliance.[49]

Variable Cost: Fuel

36. In its August 18, 2014 Filing, PNM states that it constructed a supply curve ''in the model for each entity by estimating its unit-specific incremental dispatch costs. The incremental cost is calculated by multiplying the fuel cost for the unit by the unit's efficiency (heat rate) and adding any additional variable costs that may apply, *i.e.,* costs for variable operations and maintenance and costs for environmental offsets.'' [50] PNM further clarifies that ''[t]he characteristics for all of the units included in the analysis, including their estimated incremental costs, are included in work papers.'' [51] PNM states that incremental costs were derived by multiplying unit specific heat rates (generally from the Energy Information Administration (EIA) Form 860 or *Ventyx*) by fuel prices (from FERC Form 423 for the Study Period, as reported by *Ventyx*) and then adding VOM and any applicable environmental adders.

37. Fuel is a significant component of variable cost, and natural gas- and coal-fired generation is a significant portion of the generation analyzed by PNM.[52] PNM takes a number of steps to compute a fuel price for generators to determine whether they are economic in each of the 10 season/load levels. PNM appears to use natural gas price data from the ''ICE10x Day Ahead Gas Prices'' for the El Paso Gas (Permian Basin) and El Paso—South Mainline locations.[53] Further, PNM appears to use EIA and Velocity Suite data to compute coal prices across the Western Electricity Coordinating Council (WECC) region.

38. For natural gas, PNM computes seasonal prices at the two locations mentioned above by averaging all of the hourly prices for each location in each season/load level. These two locations seem to be the hubs that are closest to the PNM balancing authority area. However, PNM also includes in its spreadsheets hourly gas prices for 22 locations in the WECC region.[54] The summer average prices for the 22 locations range from $1.88 at ''Questar North Pool'' to $3.27 at ''PG&E-Citygate,'' a variation of almost 74 percent. Although PNM submitted data for 22 locations, it only used prices from the two hubs identified above to calculate input costs for all gas-fired generators in the WECC region.

39. Additionally, PNM uses only three natural gas prices in its model, one for each of the summer, winter and shoulder seasons. To do this, for the one-hour Summer Super Peak 1 (S_SP1)

[45] We note that the Velocity Suite database indicates that the San Onofre plant units 2 and 3 last generated electricity in January 2012, while the study period for the DPT analysis was December 2012 through November 2013. This information is sourced from the Ventyx, Velocity Suite database in September 2015. We note that the San Onofre plant is currently in the process of decommissioning. *See* Decommissioning of San Onofre, *http://www.songscommunity.com.*

[46] Response to the Data Request, Workpaper ''Wkp—Suppliers Details.xlsx'' (Tab ''AEC By Suppliers—Base Prices''). *See also* Whitewater Hill Wind Partners, LLC, Docket No. ER02–2309–000 at 1 (filed July 11, 2002); *Whitewater Hill Wind Partners, LLC,* Docket No. ER02–2309–000 (Aug. 29, 2002) (delegated letter order accepting filing). Note also that the comments in the spreadsheet submitted by PNM identify Whitewater Hill Wind Partners as being under a long-term contract. There are additional cells in PNM's spreadsheets that identify certain generating facilities as having EC or AEC even though the spreadsheets also show those facilities as being under long-term contracts.

[47] We note that here we describe Whitewater Hill Wind Partners for illustrative purposes only, and not because it is the only entity listed in PNM's DPT analysis that lacks EC or AEC.

[48] 18 CFR 33.3(c)(4)(i)(A) (2015) (''Economic capacity means the amount of generating capacity owned or controlled by a potential supplier with variable costs low enough that energy from such capacity could be economically delivered to the destination market. Prior to applying the delivered price test, the generating capacity meeting this definition must be adjusted by subtracting capacity committed under long-term firm sales contracts and adding capacity acquired under long-term firm purchase contracts (*i.e.,* contracts with a remaining commitment of more than one year.'').

[49] 18 CFR 33.3(d)(2)(i) (2015). Additionally, ''[t]o the extent costs described in paragraph (d)(2)(i) of this section are allocated among units at the same plant, allocation methods must be fully described.'' 18 CFR 33.3(d)(2)(ii) (2015).

[50] August 18, 2014 Filing, Carey Aff. ¶ 34. We note that ''Ventyx'' is the same database as ''Velocity Suite'' also referred to as ''Velocity.'' In this order we use the term ''Velocity Suite'', except for where the term ''Ventyx'' or ''Velocity'' is used in direct quotes from PNM's filings. We note that the acronym ''VOM'' used above in PNM's description of variable costs is generally interpreted to mean ''Variable Operations and Maintenance'' costs.

[51] August 18, 2014 Filing, Carey Aff. ¶ 34 n.36.

[52] For instance, natural gas-fired generation accounts for 28 percent of the nameplate generation capacity in the underlying PNM dataset. *See id.,* Workpaper ''Gas Prices Final.xlsx.''

[53] *See id.,* Workpaper ''Gas Prices Final.xlsx'' (Tab ''Wkp—Gas Prices''); December 17, 2014 Filing, Workpaper ''Wkp PNM DPT Public Inputs.xlsx'' (Tab ''Wkp—Gas Prices,'' Tab ''Wkp—Coal Spot Prices,'' Tab ''Wkp—Detailed Coal Transactions'').

[54] August 18, 2014 Filing, Workpaper ''Gas Prices Final.xlsx'' (Tab ''Wkp—Gas Prices'').

season, PNM computes a price of $3.57/MMBtu at El Paso Gas (Permian Basin) and $3.81/MMBtu at El Paso—South Mainline. In a similar way, PNM calculates prices for the remaining seasons/load levels at each of these locations. Next, PNM calculates the average of the El Paso Gas (Permian Basin) and El Paso—South Mainline seasonal prices in order to attain 10 average seasonal natural gas prices. PNM then calculates the average over the four summer seasons/load levels as the summer natural gas price, and uses that as the natural gas price for all four summer seasons/load levels in its model. PNM calculates Winter and Shoulder seasonal natural gas prices similarly.

40. Further, PNM submitted work papers that include an average coal price for 83 plants with unique EIA identification numbers. Only seven of these plants appear to be in the WECC region, although there are more than seven coal-fired plants in WECC. These average prices were calculated from monthly ''Detailed Coal Transactions From December 2012 to November 2013,'' [55] but not every plant has an average price for each month and some plants include more than one average price for some months. The average prices for the seven WECC plants range from $1.42 to $2.52 per MMBtu, but do not account for any seasonality in coal prices. In its generation dataset, PNM appears to attribute the calculated coal price for each of the seven plants as that plant's input cost, but then uses the average of all seven as the input price for all other coal-fired generators in the WECC.

41. Sellers should account for some measure of regional differences in fuel price. As described above, PNM used one natural gas price for each of the three seasons' seasonal gas price estimate for all gas-fired generation in the entire WECC, which are derived from the average prices at two hubs. That is, PNM used the same natural gas fuel costs for generators in Alberta, Northern and Southern California and New Mexico even though PNM's own spreadsheets detail the locational variation in natural gas prices across the WECC region. As explained above, the fuel cost of each generating facility is one of the main factors in determining whether the output of that facility should be included as EC in a DPT analysis. Oversimplifying the variable cost calculations by assuming that all gas-fired generators have the same input cost regardless of their location may cause certain units, whose actual gas prices are lower than these averages, to be inappropriately considered uneconomic and may cause units whose actual gas prices are higher than these averages to be inappropriately considered economic. Thus, regional price variation for input fuels should be considered in a model that includes competing supply capacity from a large geographic footprint, and a generator's fuel cost should be estimated from a nearby price point unless the seller explains why another methodology is reasonable. Furthermore, we note an apparent contradiction between the seven coal prices used in the generation data set and the single coal price reported for WECC of $1.97 [56] in the Fuel Prices Summary worksheet. However, as with natural gas prices, we would expect a coal-fired generator's fuel cost to be estimated from a nearby price point and not an average of several price points across a region as large as WECC.

42. For the reasons stated above, we cannot conclude that PNM has rebutted the presumption of market power because of the flaws in its analysis.

Variable Cost: Operations and Maintenance

43. As mentioned above, Commission regulations state that sellers must calculate, at a minimum, variable cost for a unit used in the DPT analysis. For each such generating unit, the seller must also provide variable cost components, which include operation and maintenance costs.[57]

44. PNM's DPT model contains a worksheet, ''Generation Dataset,'' that contains variable cost calculations for the WECC generators that PNM included in its model. There are 4,293 observations in this dataset and 2,118 of these observations have a zero dollar cost for VOM.[58] We note that a vast majority of these observations with a zero dollar cost for VOM are from renewable resources.

45. Although the Data Request did not specifically request that PNM provide actual values for VOM costs, we take this opportunity to provide clarification to PNM and other DPT filers. Although VOM costs may be a small component of hourly costs, we do not expect these costs for most generating units to have a zero value [59] because all generation technologies require maintenance or have at least some operational costs to produce electricity. PNM states that it uses Velocity Suite data in its model. We note that Velocity Suite provides cost estimates for various renewable generation technologies. PNM has not explained why it assumed a zero cost for VOM when estimates for this cost are available for most types of renewable generation from Velocity Suite.[60]

46. Therefore, it appears that PNM underestimates the variable cost of a significant portion of generation in its DPT model, which potentially overestimates the amount of EC calculated in its DPT analysis.

iv. Accounting for Purchase Contracts

47. As mentioned above, another step in the calculation of a supplier's EC is accounting for long-term firm purchase contracts. EC refers to ''the amount of generating capacity owned or controlled by a potential supplier with variable costs low enough that energy from such capacity could be economically delivered to the destination market.'' [61] The Commission's regulations require that ''the generating capacity meeting this definition must be adjusted by subtracting capacity committed under long-term firm sales contracts and adding capacity acquired under long-term firm purchase contracts (*i.e.,* contracts with a remaining commitment of more than one year).'' [62] The regulations further provide that ''capacity associated with any such adjustments must be attributed to the party that has authority to decide when generating resources are available for operation'' and notes that ''other generating capacity may also be attributed to another supplier based on operational control criteria as deemed

[55] December 17, 2014 Filing, Workpaper ''Wkp PNM DPT Public Inputs.xlsx'' (Tab ''Wkp—Detailed Coal Transactions'').

[56] *Id.,* Workpaper ''Wkp PNM DPT Public Inputs.xlsx'' (Tab ''Wkp—Fuel Prices Summary''). PNM used a price of $1.97 for Winter, Summer, and Shoulder season.

[57] 18 CFR 33.3(d)(2) (2015).

[58] December 17, 2014 Filing, Workpaper ''Wkp PNM DPT Public Inputs.xlsx'' (Tab ''Generation Dataset'').

[59] We note that although EIA states that wind generation has a relatively small VOM cost, EIA uses a zero cost for all non dispatchable generation in its Annual Energy Outlook 2015 Reference Case model. *See* EIA, *Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2015* (June 2015), *available at http://www.eia.gov/forecasts/aeo/pdf/electricity_generation.pdf.*

[60] A Velocity Suite supply curve for the PNM balancing authority area for July 31, 2013, provides a range of VOM cost estimates for most types of renewable generation. Specifically, Velocity Suite provides a VOM in $/MWh of $1.26 to $1.56 for the hydro plants; $1.90 to $2.06 for photovoltaic generation; $1.25 for energy storage devices; and $4.79 for biomass facilities. Velocity Suite does not provide a VOM cost for wind generation. Velocity Suite states that its estimates are based on many sources of unit or plant data and are calculated in an internal model.

[61] *See* 18 CFR 33.3(c)(4)(i)(A) (2015).

[62] *Id.*

necessary, but the applicant must explain the reasons for doing so.'' [63]

48. As noted above, Commission regulations require information on all long-term firm purchases and sales ''for each sale and purchase of capacity'' as part of the DPT analysis.[64] A seller performing a DPT analysis should account for the purchase contracts of potential suppliers because the contracts may affect the competitive situation of a supplier in a DPT analysis. A supplier with a contractual obligation to sell energy or capacity may not have any AEC to be considered as competing in the DPT analysis. Conversely, a supplier with the contractual obligation to purchase supply may have excess energy and become a potential supplier in the DPT analysis. The determination of whether a supplier with purchase contracts has EC or AEC depends on a number of factors specific to that supplier such as the supplier's native load (if any), the amount of generation the supplier has to meet that load, including any contracts the supplier has to buy or sell energy or capacity, and the prevailing market price. These specific factors should be accounted for in a DPT analysis to determine whether a potential supplier with purchase contracts is a potential competitor.

49. The Data Request sought information from PNM concerning how certain sellers could be considered competitive suppliers for purposes of the DPT analysis when each of those seller's native load appeared to exceed its generation capacity. Specifically, PNM was asked to explain whether one particular supplier, Tri State Generation & Transmission Association Inc. (TriState), could have any uncommitted capacity to compete with PNM given that TriState's peak load is reported to be greater than its generation capacity. The Data Request did not specifically identify any other sellers in a similar situation to TriState. However, the Data Request directed PNM to identify every potential supplier for whom its study deducted native load obligations, the amount of those obligations and the source of their native load values.[65] Finally, the Data Request directed PNM to adjust its model as needed to reflect TriState and other sellers that have load greater than their respective uncommitted capacity.[66]

50. In its Response to the Data Request, PNM stated that there are differences between the reporting in the data sources that the Commission used to formulate its questions and the data source(s) PNM used in its calculation of competitive supply. PNM further added that TriState ''has substantial purchase agreements, including ownership in [WECC] output facilities that would not be tracked by Velocity.'' [67] PNM did not mention any other sellers who might be in this similar situation.

51. We appreciate PNM's Response to the Data Request but find that more information is necessary. While PNM provided information on TriState's purchasing, it did not disclose the amount of power purchased under these contracts that would enable TriState to meet its native load requirements and have sufficient generation to be a competitive supplier in the DPT analysis. PNM also did not meet the reporting requirements for long-term contracts of sales and purchases in 18 CFR 33.3(d)(3) for TriState or for any other suppliers, such as Whitewater Hill Wind Partners, whose output is fully committed under long-term contract to another entity. Additionally, in its Response to the Data Request, PNM did not indicate whether there are other potential suppliers with long-term contracts or adjust its model to reflect any other potential suppliers with native load obligations greater than their respective generation capacity.

52. Generation units in a supplier's portfolio whose output is committed under long-term firm contracts should not be considered available to compete in the study area as AEC. Including such capacity may overstate the amount of AEC that a potential supplier can contribute or inaccurately attribute that capacity to the wrong potential supplier in a DPT analysis. Additionally, incorrectly attributing capacity to sellers that have sold the output of their facilities to unaffiliated entities under purchase power agreements impacts the market concentration results of the DPT analysis. Lastly, PNM did not adjust its model as requested in the Data Request or otherwise explain that such adjustment was not required. For these reasons, we are unable to rely on PNM's DPT analysis.

v. Transmission Rates

53. As mentioned above, Commission regulations require a DPT analysis to account for any and all applicable transmission costs that a supplier would incur to deliver the energy into the study area and add these costs to the estimate of the available unit's variable generation cost. Commission regulations state that these costs must include the maximum transmission rate in a transmission provider's tariff as well as the estimated cost of supplying energy losses.[68]

54. PNM did not include all applicable transmission costs in its EC calculation. In the December 17, 2014 Filing, PNM's DPT analysis used a universal $2.00 transmission rate for all peak periods and a $1.00 transmission rate for all off-peak periods for all generators, regardless of location.[69]

55. In the Data Request, PNM was requested to provide the transmission rate schedule for the PNM balancing authority area and all of the balancing authority areas where competing suppliers are located, and to provide cites to the relevant open access transmission tariff(s).[70] The Data Request asked PNM to explain if the transmission rates used in its DPT analysis are the maximum rates for the PNM balancing authority area and the balancing authority areas where the DPT analysis indicates there is competitively priced generation.[71] Finally, the Data Request directed that, if those are not the maximum rates, PNM should re-run the AEC calculations to include the cost to traverse each balancing authority area using the maximum 'up to' transmission rate when PNM re-runs the DPT model.[72]

56. In Response to the Data Request, PNM stated that it assumed transmission rates for purposes of the model because it lacks details on specific transmission rates for some of the WECC transmission providers. PNM stated that this assumption has a *de minimis* impact on the results of the analyses. PNM also provided a spreadsheet that identifies the 24 individual balancing authority areas in WECC, their minimum and maximum transmission rates, information on the rate schedules for these balancing authority areas and screen snapshots of the appropriate Open Access Same Time Information System (OASIS) Web sites where PNM retrieved the maximum and minimum rates.[73]

57. We note that these maximum rates for the peak periods ranged from $1.26 to $10.02 and averaged $4.96. Likewise, the maximum rates for the off-peak periods ranged from $0.72 to $9.00 and averaged $3.59. In Response to the Data Request, PNM provided a sensitivity analysis that used the average of these

[63] *Id.*

[64] *See* 18 CFR 33.3(d)(3). *See also* n.37 above.

[65] *See* Data Request, Question No. 5, at 4.

[66] *See* Data Request, Question No. 6, at 4.

[67] Response to the Data Request at 8.

[68] 18 CFR 33.3(d)(5) (2015).

[69] December 17, 2014 Filing, Workpaper ''Wkp PNM DPT Public Inputs.xlsx'' (Tab ''Wkp—TTC and Tx Rates'').

[70] Data Request, Question No. 14a, at 6.

[71] *Id.,* Question No. 14b, at 6–7.

[72] *Id.,* Question No. 14c, at 7.

[73] *See* Response to the Data Request, ''WECC OATT Rates.xlsx.''

maximum transmission rates to update its DPT model.[74] PNM complied with the first part of Question 14 by identifying that the $2.00 and $1.00 transmission rates are not the maximum rates for the peak and off-peak periods, respectively. PNM also identified the 24 source balancing authority areas and provided a link and screen snapshots of the OASIS Web sites for these balancing authority areas that display their maximum and minimum rates.

58. However, we find the remaining portion of PNM's Response to the Data Request to be unresponsive to the question asked and not in compliance with Commission regulations. PNM did not re-run the DPT analysis with the maximum rate for *each* balancing authority area as requested in the Data Request [75] and required by Commission regulations.[76] Furthermore, PNM did not calculate any additional costs for transmission losses or ancillary services necessary to deliver energy into the study area, as required by Commission regulations.[77] For capacity outside of the study area, PNM did not consider additional transmission charges that a competing generator would likely incur to deliver power to the destination market. Therefore, we find that PNM's calculations underestimate the transmission cost component for most observations in its dataset and further compromise the results of the DPT analysis.

vi. Calculation of AEC

59. As mentioned above, alternative suppliers should be able to reach the market both economically and physically.[78] First, we discuss how to determine the AEC of a supplier.

60. After computing the EC of potential competing suppliers, an applicant should compute the AEC of those suppliers. AEC is ''the amount of generating capacity meeting the definition of EC less the amount of generating capacity needed to serve the potential supplier's native load commitments.'' [79] We note that the Commission has relied more heavily on AEC in the DPT analysis when utilities have significant native load.[80] Further, in Order No. 697, the Commission stated that ''in markets where utilities retain significant native load obligations, an analysis of available economic capacity may more accurately assess an individual seller's competitiveness, as well as the overall competitiveness of a market, because available economic capacity recognizes the native load obligations of the sellers.'' [81]

61. The Data Request directed PNM to explain whether its DPT model first allocated the lowest running cost units to a supplier's native load and cited to the Merger Policy Statement.[82] In Response to the Data Request, PNM stated, in part, that ''[t]he model implicitly allocates PNM's lowest running cost units to serve native load for PNM and non-PNM suppliers to their native load (non-PNM load) by the derivation of the [AEC]. The DPT model does not rank order each supplier's generating units from lowest to highest running cost but rather aggregates all [EC] for each supplier within the seasonal/load periods analyzed.'' [83]

62. In the Merger Policy Statement, the Commission stated that the AEC measure ''includes capacity from generating units that are not used to serve native load (or are contractually committed).'' [84] However, PNM stated that ''[t]he DPT model does *not* rank order each supplier's generating units from lowest to highest running cost but rather aggregates all economic capacity for each supplier within the seasonal/load periods analyzed.'' [85] Further, it is unclear how PNM's model might implicitly allocate an entity's lowest running cost units to serve its native load. Based on this response, we conclude that PNM did not allocate the lowest cost units of itself and its competitors to serve their respective native load. Therefore, we are unable to rely on the reported results of potential competitive AEC suppliers and whether they accurately reflect the costs of the competitive generation in the market.

vii. Historical Transaction Data to Corroborate Results

63. Commission regulations state that ''[t]he applicant must provide historical trade data and historical transmission data to corroborate the results of the horizontal Competitive Analysis Screen.'' [86] Commission regulations also state that the applicant must provide data and information used in calculating the EC and AEC that a potential supplier could deliver to a destination market, including transmission capability, transmission constraints and firm transmission rights.[87] Further, Commission direction has been to provide a ''trade data check'' to support the results of the DPT analysis.[88]

64. The Data Request directed PNM to identify suppliers with AEC and document their contribution to competing supply entering the PNM study area.[89] In its Response to the Data Request, PNM provided a spreadsheet that complied with the request by identifying all generation units, their location, and the identity of the suppliers with non-zero contribution to the AEC calculation.[90]

65. Although the Data Request did not specifically ask PNM to provide historical transaction data to corroborate the results of its DPT analysis, we take this opportunity to provide clarification for PNM and others who may file a DPT

[74] *See id.*

[75] Data Request, Question No. 14c, at 7 (''If the rates used in your model are not the maximum rate, please re-run your AEC calculations using the maximum 'up to' transmission rate to include the cost to traverse each balancing authority when you re-run your DPT model.'').

[76] 18 CFR 33.3(d)(5) (2015).

[77] 18 CFR 33.3(d)(5) (2015).

[78] Merger Policy Statement, FERC Stats. & Regs. ¶ 31,044 at 30,130.

[79] 18 CFR 33.3(c)(4)(i)(B) (2015).

[80] *Great Plains Energy, Inc.,* 121 FERC ¶ 61,069, at P 34 & n.44 (2007), *reh'g denied,* 122 FERC ¶ 61,177 (2008); *Nat'l Grid, plc,* 117 FERC ¶ 61,080, at PP 27–28 (2006), *reh'g denied,* 122 FERC ¶ 61,096 (2008); *Westar Energy, Inc.,* 115 FERC ¶ 61,228, at P 72, *reh'g denied,* 117 FERC ¶ 61,011, at P 39 (2006); *Nev. Power Co.,* 113 FERC ¶ 61,265, at P 15 (2005).

[81] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 112.

[82] Data Request, Question No. 4, at 3 (''In the [AEC] calculation, please explain whether the model first allocates PNM's lowest running cost units to serve native load for PNM. Please explain whether the model allocates the lowest running cost units of non-PNM suppliers to their native load (non-PNM load).''). The Data Request noted that ''AEC includes 'capacity from generating units that are not used to serve native load (or are contractually committed) and whose variable costs are such that they could deliver energy to a market at a price close to the competitive price in the market. The presumption underlying this measure is that the lowest running cost units are used to serve native load and other firm contractual obligations and would not be available for other sales.''' Data Request, Question No. 4 n.6, at 3 (citing Merger Policy Statement, FERC Stats. & Regs. ¶ 31,044 at 30,132).

[83] Response to the Data Request at 7.

[84] Merger Policy Statement, FERC Stats. & Regs. ¶ 31,044 at 30,132.

[85] Response to the Data Request at 7 (emphasis added).

[86] 18 CFR 33.3(c)(6) (2015).

[87] *See* 18 CFR 33.3(d)(7)–(9) (2015).

[88] *See* Merger Policy Statement, FERC Stats. & Regs. ¶ 31,044 at 30,133 (''It would be expected that there be some correlation between the suppliers included in the market by the delivered price test and those actually trading in the market. As a check, actual trade data should be used to compare actual trade patterns with the results of the delivered price test. For example, it may be appropriate to include current trading partners in the relevant market even if the above analysis indicates otherwise.'').

[89] Data Request, Question No. 15, at 7 (''Please provide the following information for each supplier with a non-zero contribution to the available economic capacity in the study area of your model: the full name of each supplier, the name of the unit(s) that supplied the energy, the amount of energy supplied by each unit(s) in megawatts and the balancing authority area location of the unit(s) for each of the 10 load level/study periods.'' (footnote omitted)).

[90] Response to the Data Request at 12 & Workpaper ''Wkp—Suppliers Details.xlsx.''

analysis in a section 205 proceeding in order to rebut the presumption of market power. PNM did not submit historical transaction data or transmission data to corroborate the results of its model as required by 18 CFR 33.3(c)(6). For example, although PNM indicates in its Response to the Data Request that its model includes significant generation capacity from the California Independent System Operator Corporation (CAISO) market as available to compete in the PNM balancing authority area, PNM did not submit historical transaction data or transmission data to corroborate this. PNM could have submitted eTag data to demonstrate flows from CAISO were consistent with its DPT model. Moreover, the Commission's review of eTag data was not able to corroborate PNM's results. Without such information, we are concerned that the amount of competing generation capacity imported into the PNM study area in PNM's DPT analysis is not supported by historical trade or transmission data and is overstated. We remind DPT filers that they should provide historical trade and transmission data and explain significant discrepancies between modeling results and such data.

viii. SIL Study

66. As mentioned above, alternative suppliers must be able to reach the market both economically and physically. We provide clarification regarding determining the physical capability of a supplier with EC and AEC to reach the study area.[91]

67. The physical ability of a supplier to reach the market or study area requires the use of a SIL study as a basis for transmission access for both the indicative screens and the DPT analysis.[92] In Order No. 697, the Commission clarified that the SIL study as shown in Appendix E of the April 14 Order is the only study that meets the Commission's requirements for the DPT analysis and the indicative screens.[93] In the April 14 Order, the Commission set the amount of supply that can reach the relevant market as uncommitted capacity limited by the simultaneous transmission import capability.[94] In *Puget Sound Energy, Inc.,* the Commission consolidated and clarified its direction regarding SIL studies given in previous orders and provided required formats for submitting SIL data.[95] Specifically, the Commission directed filers to submit their SIL data in the format provided in Appendix B of *Puget* in order to properly summarize and document their SIL study results.[96]

68. The SIL study calculates the aggregated simultaneous transfer capability into the balancing authority area being studied. It is intended to provide a reasonable simulation of historical conditions and is not a theoretical maximum import capability or best import case scenario.[97] A simplified view of the SIL study is that it simultaneously increases generator output in one area, the first-tier, and decreases generator output in another area, the study area. As the source of generation is incrementally shifted, single contingency conditions are tested in both areas while the relevant transmission elements are monitored for overloads.[98] A ''single contingency condition'' is the unexpected failure of a single system component, such as a generator, transmission line, circuit breaker, switch or other electrical equipment.[99] The Commission direction has been to increase or ''scale up available generation in the exporting (aggregated first tier areas) and scale down the study area resources according to the same methods used historically in assessing available transmission for non-affiliate resources.'' [100]

69. The Commission recognizes that it is a complex process for a seller to estimate transmission capability using the model of its transmission system in a simplified manner so that elements are accurately accounted for in SIL studies. Therefore, the Commission previously has provided guidance so that sellers can more accurately measure the amount of available transmission capability into the study area. One area of concern has been the proper modeling and scaling of jointly-owned generating plants in a SIL study, particularly when units have long-term firm transmission reservations.[101] The Commission has determined that these remote plants should be dispatched at their historical output levels and should not be scaled down as doing so would be unrealistic and inconsistent with historical practices.[102]

70. In *Pinnacle West,*[103] the Commission identified errors and provided guidance and clarification as to how the SIL study should be revised to satisfy the Commission's requirements. The PNM SIL study presents issues similar to those presented by the SIL study at issue in *Pinnacle West.* With regard to the PNM SIL study, the Data Request noted that some units within the study area have long-term firm commitments to serve load outside of the study area. The Data Request noted that the Commission expects that any such unit's generation that has been committed with long-term firm transmission reservations would be considered unavailable for scaling; however, it appears that some such units were scaled down during the SIL study. Therefore, the Data Request required PNM to identify all generation units within the PNM balancing authority area that have long-term firm transmission reservations (to serve study area load or to export power to the first-tier), describe whether the unit's output level was either maintained or scaled in the SIL study, and adjust the SIL study as necessary.[104]

71. In its Response to the Data Request, PNM filed revised work papers and SIL information. PNM also submitted a table listing the long-term firm transmission reservations for exports out of the PNM balancing

[91] In this order, we do not discuss the ultimate DPT calculations, combining the economic and physical analyses to create market share and concentration indices because we do not believe that the first two steps of the PNM DPT analysis provide a reasonable foundation to examine this final step.

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

[93] *Id.* (''With regard to [SILs], the Commission adopts the requirement that the SIL study be used as a basis for transmission access for both the indicative screens and the DPT analysis. Further, the Commission clarifies that the SIL study as shown in Appendix E of the April 14 Order is the only study that meets our requirements.'').

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

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

[96] Submittal 1 of Appendix B of *Puget* contains a summary table of components used to calculate SIL values and provides a spreadsheet format with numerical examples. Submittal 2 provides a spreadsheet for identification of long-term firm transmission reservations used to import power from seller and affiliate generating resources in a first-tier area to serve native load in the study area.

[97] *Puget,* 135 FERC ¶ 61,254 at Appendix B (citing Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 354).

[98] *See, e.g., Puget,* 135 FERC ¶ 61,254, Appendix B, § I.D (Prior Commission Direction on Scaling).

[99] *Id.* Appendix B (citing *Carolina Power & Light Co.,* 128 FERC ¶ 61,039, at P 8 n.7 (2009)).

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

[101] A long-term firm transmission reservation is a reservation that is 28 days or longer. *See* Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 368 (''While we find that firm transmission reservations less than or equal to 28 days in duration are usually unpredictable, we believe that firm transmission reservations of a longer duration are not related to the unpredictable nature of real time events and are based upon planned and predictable events. Therefore, the Commission will require sellers to account for firm and network transmission reservations having a duration of longer than 28 days.'').

[102] *See Pinnacle West Capital Corp.,* 117 FERC ¶ 61,316, at P 6 (2006) (*Pinnacle West*).

[103] *Id.* P 3.

[104] Data Request, Question No. 2, at 2 (citing *Pinnacle West,* 117 FERC ¶ 61,316 at P 6; April 14 Order, 107 FERC ¶ 61,018 at Appendix E).

authority area and the corresponding source generator within the study area. This table indicates that these generation units are jointly-owned by PNM and other entities, and that the non-PNM owned portions of these units are committed with long-term firm transmission reservations to export out of the study area (*i.e.,* the PNM balancing authority area). However, based on the power flow models submitted by PNM in the original SIL study, it is evident that PNM scaled down these jointly-owned generation units, including portions belonging to other owners.[105] In addition, PNM provided Submittal 1 and Submittal 2 tables which reported the results of two sensitivities that PNM conducted in response to the scaling guidance in the Data Request.

72. PNM's first sensitivity study ''does not scale resources with potential commitments outside of the PNM [balancing authority area].'' [106] The second sensitivity ''scales half of the resources with potential commitments outside of the PNM [balancing authority area].'' [107] However, for both sensitivities, PNM stated that ''the associated export reservations are recognized as long-term firm commitments to be consistent and reflect the equal but opposite effect to import reservations and compensate for prematurely limiting the imports below the physical limit of the transmission system or load within the study area. The export reservations are reflected in the SIL sensitivity analyses by inclusion in Table 2 [of Submittal 2].'' [108]

73. The practice of capturing long-term firm export reservations in Submittal 2 is inconsistent with the instructions and purpose of Submittal 2, which is to identify and sum the long-term firm transmission reservations from affiliated remote generating resources in the first-tier to serve native load in the study area.[109] Export reservations are long-term firm transmission reservations *from* the study area to the first-tier to serve first-tier load; because the exports are commitments from capacity that belongs to the first-tier, these export reservations should not be captured in Submittal 2. As such, the Commission cannot utilize these sensitivities as support for PNM's SIL study. Furthermore, while the scaling method used in the first sensitivity is consistent with guidance given in the Data Request, the ownership and commitments of the generation units was not apparent in the original August 18, 2014 Filing or the December 17, 2014 Filing. Thus, we believe that further clarification is warranted on the modeling and treatment of jointly-owned units in SIL studies.

74. In *Puget,* the Commission stated that ''[i]n the case of jointly-owned power plants, the plant's capacity should be allocated among the generator owners' balancing authority areas according to its ownership percentages.'' [110] Additionally, the Commission has stated that a seasonal benchmark case model should simulate historical seasonal conditions that were present during the modeled season. The Commission has stated that ''[a]ny generating units owned by the study area utility that are located in the first-tier area, including the study area utility's portion of jointly-owned units[,] should be modeled . . . in the first-tier area.'' [111] In addition, ''any long-term reservations from these facilities used to serve study area native load shall be included in the study area net area interchange.'' [112] While this statement references jointly-owned generating units located in the first-tier area, we believe that it is reasonable to treat jointly-owned generating units located within the study area committed to serving first-tier load similarly. As portions of these units belong to unaffiliated entities located in the first-tier area, they should not be scaled down; doing so would misrepresent the incremental transfer capability of the study area by reducing generation that actually has commitments to first-tier load.[113] This has the effect of allowing more first-tier generation into the study area than is actually available to be displaced in the study area.

75. Thus, we clarify that, for purposes of generation scaling for the SIL, the appropriate method of modeling a generation unit in the study area that is jointly-owned between the seller and one or more unaffiliated sellers in the first-tier area is to represent the unit as multiple units in the model based on ownership percentage such that the multiple units fully represent the generation commitments and impacts on the transmission system. One unit will represent the seller's generation capacity in the study area, and one or more additional units will represent the capacity owned by unaffiliated entities within the first-tier area.[114] The seller's unit will remain modeled within the study area balancing authority area while the portion of the unit(s) belonging to unaffiliated first-tier sellers will be given the appropriate first-tier balancing authority area number in the model. Importantly, we note that this method retains the same physical location of the unit within the transmission network as modeled; however, the portion of the unit(s) belonging to the unaffiliated first-tier sellers would not be considered a study area generator for purposes of calculating net area interchange. We also note that with this method, the seller's generation capacity can appropriately be scaled down, and the portion of the unit(s) belonging to the unaffiliated first-tier sellers now modeled in the first-tier area can appropriately be scaled up to serve study area load if it is not committed under long-term firm transmission reservations. Additionally, any generating resources in the first-tier with long-term firm transmission reservations to serve study area load should be reported as a long-term firm transmission reservation in Submittal 2.[115] Furthermore, entities are required to ''[p]rovide a listing of first-tier area generating units and portions of jointly-owned first-tier area generating units to be scaled-up in the first-tier area, including any first-tier area generation or portions of jointly-owned first-tier area generating units physically located within the study area, according to the same methods used historically in assessing available transmission for non-affiliate resources.'' [116] Entities should identify their jointly-owned units, report the ownership breakdown, and indicate what scaling, if any, was utilized for each portion of the generator.

76. Finally, we clarify that entities should complete the ''Description of Remote Resources'' column as necessary

[105] August 18, 2014 Filing, Stahlhut Aff. Exhibit JWS–3.

[106] Response to the Data Request at 3. We interpret PNM's language ''resources with potential commitments'' to mean the long-term firm transmission reservations capacity or export reservations of the units within the PNM balancing authority area that have long-term firm transmission reservations to serve load in the first tier.

[107] *Id.* at 4.

[108] *Id.* at 3–4.

[109] *Puget,* 135 FERC ¶ 61,254, at Appendix B, § II.B.

[110] *Id.* P 18.

[111] *Id.,* Appendix B, II.D at 4.3.7.

[112] *Id.*

[113] *See id.,* Appendix B, § II.D (Submittal 4: Seasonal Benchmark Case) (4.3.7 and 4.3.8 discuss how jointly-owned units should be modeled according to historical dispatch).

[114] In *Puget,* the Commission approved NorthWestern's use of this general method to represent the jointly-owned Colstrip plant. The model represented separate generators for each owner, each with one owner's portion of Colstrip's total capacity. *Id.* P 18.

[115] *Id.,* Appendix B, II.B, Instruction 3.

[116] *Id.,* Appendix B, II.G (Submittal 7: The Sub-System File) (7.2.1).

in each row of Submittal 2.[117] We expect that, at a minimum, entities will indicate the balancing authority area from which these remote resources are sourced.

Conclusion

77. As described above, we are unable to validate the results of PNM's SIL model, its calculations of EC and AEC, and its DPT analysis. Thus, we find that PNM has not adequately rebutted the presumption of horizontal market power caused by its failure of the indicative screens in the PNM balancing authority area. Therefore, we reject, without prejudice, PNM's request for market-based rate authorization in the PNM balancing authority area. We encourage other market-based rate applicants to make use of the guidance and clarification offered herein.

D. Notice of Change in Status

78. PNM states that its purchase of Delta Person does not affect PNM's horizontal market power because PNM was already deemed to control the output of the Delta Person facility under a long-term contract with Delta Person.[118] In its most recent updated market power analysis for the Southwest region, PNM studied Delta Person's generation in the first-tier balancing authority areas in which PNM has market-based rate authority.[119]

79. Based on PNM's representations, we find that PNM satisfies the Commission's requirements for market-based rates regarding horizontal market power in all balancing authority areas in which PNM currently has market-based rate authority, *i.e.,* outside of the PNM and El Paso Electric balancing authority areas.

80. PNM represents that of it and its affiliates, only PNM owns or controls transmission facilities subject to Commission jurisdiction. PNM states that open access to these transmission facilities is provided pursuant to the terms of PNM's Open Access Transmission Tariff on file with the Commission.[120] Further, PNM represents that neither it nor any affiliate owns or controls intrastate natural gas transportation, storage, or distribution facilities. PNM represents that it owns several sites that may be used for generation capacity development including sites in which PNM has existing facilities. PNM states that it currently has plans to develop new generation at or near the San Juan Generating Station in the PNM balancing authority area. Additionally, PNM states that it holds one undeveloped site near Albuquerque, New Mexico.

81. PNM states that it purchases coal under various long-term agreements but does not currently own any coal mines or mineral rights. PNM represents that these coal purchase contracts are used exclusively to supply coal to power plants owned and operated by PNM.

82. Finally, PNM states that it has not erected barriers to entry into the relevant market, the PNM balancing authority area, and will not erect barriers to entry into the relevant market.

83. Based on PNM's representations, we find that PNM satisfies the Commission's requirements for market-based rates regarding vertical market power.

84. Based on PNM's satisfaction of the Commission's requirements for market-based authorization regarding horizontal and vertical market power in the markets where it has market-based rate authority, we accept PNM's notice of change in status.

E. Reporting Requirements

85. An entity with market-based rate authorization must file an Electric Quarterly Report (EQR) with the Commission, consistent with Order Nos. 2001 [121] and 768,[122] to fulfill its responsibility under section 205(c) [123] of the Federal Power Act to have rates on file in a convenient form and place.[124] PNM must file EQRs electronically with the Commission consistent with the procedures set forth in Order No. 770.[125] Failure to timely and accurately file an EQR is a violation of the Commission's regulations for which PNM may be subject to refund, civil penalties, and/or revocation of market-based rate authority.[126]

86. PNM must timely report to the Commission any change in status that would reflect a departure from the characteristics the Commission relied upon in granting market-based rate authority.[127]

87. Additionally, PNM must file an updated market power analysis for all regions in which it is designated as a Category 2 seller in compliance with the regional reporting schedule adopted in Order No. 697.[128] The Commission also reserves the right to require such an analysis at any intervening time.

The Commission orders:

(A) PNM's notice of change in status is hereby accepted for filing, as discussed in the body of this order.

(B) PNM's request for market-based authority in the PNM balancing authority area is hereby rejected, without prejudice, as discussed in the body of this order.

(C) PNM's SIL study is hereby rejected, without prejudice, as discussed in the body of this order.

(D) The Secretary is hereby directed to publish a copy of this order in the **Federal Register**.

By the Commission.

Issued: October 15, 2015.

Kimberly D. Bose,

Secretary.

[FR Doc. 2015–26724 Filed 10–20–15; 8:45 am]

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[117] *Id.,* Appendix B, II.B (Submittal 2: Identification of Long-Term Firm Transmission Reservations used to Import Power for Generating Resources in the First-Tier Area to Serve Native Load in the Study Area) (Instruction 2).

[118] August 18, 2014 Filing at 1.

[119] *Public Service Company of New Mexico,* Docket No. ER10–2302–004 (Aug. 22, 2014) (delegated letter order). PNM has market-based rate authority in seven first-tier balancing authority areas to the PNM balancing authority area. These balancing authority areas are Southwestern Public Service Company, Western Area Power Administration-Colorado Missouri, Western Area Power Administration—Lower Colorado, Public Service Company of Colorado, Arizona Public Service Company, Salt River Project, and Tucson Electric Power Company.

[120] Public Service Company of New Mexico, FERC FPA Electric Tariff, PNM Open Access Transmission Tariff.

[121] *Revised Public Utility Filing Requirements,* Order No. 2001, FERC Stats. & Regs. ¶ 31,127, *reh'g denied,* Order No. 2001–A, 100 FERC ¶ 61,074, *reh'g denied,* Order No. 2001–B, 100 FERC ¶ 61,342, *order directing filing,* Order No. 2001–C, 101 FERC ¶ 61,314 (2002), *order directing filing,* Order No. 2001–D, 102 FERC ¶ 61,334, *order refining filing requirements,* Order No. 2001–E, 105 FERC ¶ 61,352 (2003), *order on clarification,* Order No. 2001–F, 106 FERC ¶ 61,060 (2004), *order revising filing requirements,* Order No. 2001–G, 120 FERC ¶ 61,270, *order on reh'g and clarification,* Order No. 2001–H, 121 FERC ¶ 61,289 (2007), *order revising filing requirements,* Order No. 2001–I, FERC Stats. & Regs. ¶ 31,282 (2008).

[122] *Electricity Mkt. Transparency Provisions of Section 220 of the Fed. Power Act,* Order No. 768, FERC Stats. & Regs. ¶ 31,336 (2012), *order on reh'g,* Order No. 768–A, 143 FERC ¶ 61,054 (2013).

[123] 16 U.S.C. 824d(c) (2012).

[124] *See Revisions to Electric Quarterly Report Filing Process,* Order No. 770, FERC Stats. & Regs. ¶ 31,338, at P 3 (2012) (citing Order No. 2001, FERC Stats. & Regs. ¶ 31,127 at P 31).

[125] Order No. 770, FERC Stats. & Regs. ¶ 31,338.

[126] The exact filing dates for these reports are prescribed in 18 CFR 35.10b (2015). Forfeiture of market-based rate authority may require a new application for market-based rate authority if the applicant wishes to resume making sales at market-based rates.

[127] *Reporting Requirement for Changes in Status for Public Utilities with Market-Based Rate Authority,* Order No. 652, FERC Stats. & Regs. ¶ 31,175, *order on reh'g,* 111 FERC ¶ 61,413 (2005); 18 CFR 35.42 (2015).

[128] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at PP 848–850.