UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Reactive Supply Compensation in Markets Operated by Regional Transmission Organizations and Independent System Operators	))))	Docket No. AD16-17-000

COMMENTS OF THE ELECTRIC POWER SUPPLY ASSOCIATION

The Electric Power Supply Association ("EPSA")[1] respectfully submits these comments in response to the Federal Energy Regulatory Commission ("FERC" or "Commission") June 22, 2016 Supplemental Notice[2] that established a date for submittal of post-conference comments for the June 30, 2016 workshop associated with the above-captioned proceeding on reactive supply compensation in organized markets. The workshop explored the types of costs incurred by generators for providing reactive supply capability and whether those costs are being recovered solely as compensation for reactive supply. The workshop also looked at different methods by which generators receive compensation for reactive supply.

EPSA's comments address the following issues:

- Reactive supply is a critical service that requires compensation, which should occur consistently across markets;

[1] EPSA is the national trade association representing leading competitive power suppliers, including generators and marketers. Competitive suppliers, which collectively account for 40 percent of the installed generating capacity in the United States, provide reliable and competitively priced electricity from environmentally responsible facilities serving power markets. EPSA seeks to bring the benefits of competition to all power customers. The comments contained in this filing represent the position of EPSA as an organization, but not necessarily the views of any particular member with respect to any issue.

[2] *Reactive Supply Compensation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Docket No. AD16-17-000 (June 22, 2016) (Supplemental Notice of Workshop).

- Changes to compensation for reactive supply, including in circumstances involving asset deactivation or ownership transfers, should be appropriately addressed pursuant to existing Federal Power Act ("FPA") and Natural Gas Act ("NGA") rules;
- The AEP compensation methodology remains the most appropriate way to compensate reactive supply, and compensation should be addressed uniformly across markets through one rulemaking process for consideration and development; and,
- Compensation should be based on nameplate capacity as it appropriately signals and supports needed investment.

I. COMMENTS

A. Reactive Supply is a Critical Reliability Service that Requires Compensation

Several panelists at the workshop made the point that reactive power "was central to reliability."[3] The Commission has previously recognized the critical reliability value of reactive supply.[4] The North American Electric Reliability Corporation ("NERC") also believes that reactive power is a critical service needed to maintain Bulk Power System ("BPS") reliability as stated in their work on Essential Reliability Services ("ERS").[5] This is particularly true today and going forward as the BPS transforms to meet evolving local, state and federal policies which are driving changes in the electricity supply resource mix. With this evolution and increased reliance on intermittent and distributed resources, those essential services that maintain reliability of

[3] Video Archive for FERC June 30 Workshop, http://ferc.capitolconnection.org/063016/fercarchive_flv.htm

[4] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,705, 31,716 (1996); Order No. 890 and Order No. 2003

[5] Essential Reliability Services Report, NERC 2015, Http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Framework%20Report%20-%20Final.pdf.

the grid must get economic signals and incentives for investment and maintenance. This requires that critical reliability services are sufficiently compensated to ensure provision of the existing service and to facilitate sufficient levels of reactive supply in the future.

At the workshop, FERC Staff inquired about compensation methodology in Independent System Operator ("ISO) and Regional Transmission Organization ("RTO") markets. EPSA believes the need for compensation is clear, as it is for other services such as frequency response and regulation, and that this may best be assured by the implementation of one consistent methodology across all markets. Because reactive is a separate local service, it is best suited to be a cost-based service, as is the case under the current AEP methodology. The workshop included robust discussion on whether to use nameplate capability to establish the amount of reactive power capability, or whether test data should be used instead. EPSA strongly supports retaining the use of nameplate capability, as explained more fully below. Over the course of the workshop, many panelists agreed that, for both synchronous and non-synchronous generation, the AEP method should be retained, though slight modifications could be considered. Should the Commission decide to explore whether market-based methods could be utilized instead, or to require one method of compensation across markets, EPSA urges that such consideration occur in a full rulemaking process to allow deliberation, analysis and input by all market participants and interested stakeholders.

1. A Consistent Compensation Methodology Across Markets Could Ensure Adequate Payment for Reactive Power

As the RTO/ISO panelists explained at the workshop, there are essentially three different ways that compensation for reactive supply is considered. Generally PJM Interconnection, L.L.C. (“PJM”) and Midcontinent Independent System Operator, Inc. (“MISO”) use the AEP methodology; California Independent System Operator Corporation (“CAISO”) and Southwest Power Pool, Inc. (”SPP”) provide no separate compensation for reactive; and Independent System Operator of New England, Inc. (“ISO-NE”) and New York Independent System Operator, Inc. (“NYISO”) provide flat rate or formula-based compensation for reactive supply. As there are extensive concerns regarding insufficient compensation, the Commission should examine whether one methodology would ensure sufficient payment for reactive power. Such consideration should be addressed in a rulemaking proceeding to allow analysis, deliberation and comment by all interested parties and stakeholders.

PJM and MISO use the AEP methodology for reactive supply compensation, while NYISO and ISO-NE use a flat compensation rate. Conversely, CAISO and SPP improperly and unjustly provide no separate reactive compensation, or do not adequately compensate for the service. Therefore, EPSA supports the development of a compensation mechanism in CAISO and SPP, and assurance that the compensation in all of the organized markets is sufficient to support reactive power capability.

Keith Johnson, Manager of Infrastructure Policy at CAISO, stated that reactive suppliers do get paid for provision of the service in CAISO, but as discussion at the workshop pointed out, the payment – for opportunity costs only – happens only under "very infrequent circumstances."[6] What this translates to is that there is essentially no reactive compensation in that market, which is also true in SPP. CAISO and SPP's lack of a separate compensation method for reactive supply suggests a disconnect between the resources providing compensation for the service and those who are receiving the critical benefit. This is inconsistent with FERC's policy and precedent requiring compensation for ancillary services.[7] In addition, this is inconsistent with well-established cost causation principles.[8] Given the implications for the BPS in light of a changing resource mix, and the impact to reliability in those markets, EPSA believes the Commission should direct those markets to put in place a defined compensation mechanism for reactive supply.

ISO-NE and NYISO have similar stated rate mechanisms in place for reactive compensation in their markets. However, as noted by Neil Levy, King & Spalding LLP speaking for EPSA at the workshop, there are concerns that the particular rates in those markets under compensate certain generators for the provision of reactive power.[9] Because it is critical that the stated rate mechanisms offer sufficient compensation for this needed service, examination of the ISO-NE and NYISO formulas to ensure that

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[6] *Id.*

[7] Order No. 888.

[8] It has been the Commission's longstanding policy to ensure that customers who received the benefit of a service, pay the costs for that service, and that non-benefiting customers avoid liability for payment. *See Williston Basin Interstate Pipeline Co.*, 71 FERC ¶ 61,019 (1995); *ANR Pipeline Co.*, 92 FERC ¶ 61,284 (2000). *See Alabama Elec. Coop., Inc. v. Fed. Energy Regulatory Comm'n*, 684 F.2d 20, 27 (D.C. Cir. 1982); *Tejas Power Corp. v. Fed. Energy Regulatory Comm'n*, 908 F.2d 998, 1005 (D.C. Cir. 1990). The Commission has reaffirmed this policy against shifting costs to customers who are not the intended beneficiaries of the facilities for which the costs were incurred in Order No. 888. Order No. 888 at 31,798 (adopting direct assignment approach to stranded costs because consistent with cost causation principles). *See also* Order No. 888-A at 30,271, n.277, citing *Florida Municipal Power Agency v. Florida Power & Light Company*, 74 FERC ¶ 61,006 at 61,010, n.48 (1996).A

[9] Video Archive for FERC June 30 Workshop, http://ferc.capitolconnection.org/063016/fercarchive_flv.htm

they do so should be addressed in a rulemaking proceeding on reactive power compensation. For instance, the Commission could look at different methodologies to ensure revenue sufficiency, while keeping in mind the time and expense undertaken to arrive at existing reactive power rates in different markets. The goal must be, to gain the right investment to ensure that reactive power is available where it is needed, that the compensation paid to generators in these markets reflect the service capability provided.

B. Any Policy Changes Should Be Implemented Through a Rulemaking Process

EPSA understands that the workshop was intended to address forward-looking issues with respect to reactive supply compensation, and EPSA urges the Commission to implement any reactive power compensation policy changes through a rulemaking proceeding, while upholding the status quo prior to the implementation of those changes pursuant to a final rule. Forward-looking policy issues associated with reactive supply compensation will be influenced by the ongoing cases cited in the June 22 Supplemental Notice, particularly if these cases change, redefine or reinterpret existing compensation treatment and policy. If the Commission does not make it clear that it will address any reactive power compensation policy changes in a future rulemaking process on a prospective basis, EPSA is concerned that opinions concerning Commission policy between parties will differ in individual proceedings and could inhibit the settlement process going forward. While the workshop addressed whether compensation policy is currently adequate or may require revision, the array of pending reactive supply cases raise broad questions for generators regarding provision of the service, refunds, treatment of fleet-wide rates, settlements, etc., associated with compensation. These broader questions raised in existing proceedings suggest an increased risk regarding reactive supply provision based on an apparent effort to lower overall reactive power rates, even in instances where the rates have not been contested. EPSA believes it is imperative that the Commission's policies regarding reactive supply, as an essential reliability service, ensure reactive capable facilities are in place. Thereby, investors need to know that the Commission stands ready to support sufficient compensation for reactive supply provision.

The workshop agenda suggests that FERC is contemplating changing compensation methods for reactive power service. Under the FPA, a generator's reactive power rate on file with the Commission cannot be changed unless the generator files itself to change the rate under FPA Section 205, or an FPA Section 206 complaint proceeding is initiated by the Commission or a third party. The same is true for rate changes or reassessments for natural gas pipelines under Sections 4 and 5 of the NGA. The FPA and NGA thus establish very clear limitations that have worked for more than 80 years, and that cannot be ignored by the Commission in an ill-advised effort to simply lower rates. Generation owners are entitled to recover their investment (as well as a return on that investment) in the equipment used to provide reactive service. Denying generators the ability to do so would be unjust and unreasonable and a violation of the FPA.

1. Retroactive Ratemaking and FPA Sections 205 and 206

Recent proceedings in FERC Docket Nos. EL15-15 and ER15-696 regarding reactive supply rates in PJM demonstrated that PJM lacked authority to modify rates for reactive compensation,[10] and also highlighted the existing FPA provisions that provide market participants with clear rules regarding their respective responsibilities. Under the ratemaking regime as defined by the FPA, the Commission lacks authority to require a reactive power supplier to make a Section 205 filing to modify its rates in the wake of the retirement or transfer of a generation unit, as "[t]he courts have repeatedly held that FERC has no power to force public utilities to file particular rates . . . ."[11] Similarly, a Section 205 proceeding initiated by a public utility "cannot be used by the Commission to institute any change in a ratemaking component" that was not proposed by the public utility.[12] To the extent that the Commission seeks to change existing rates (including components thereof), "it has no alternative save compliance with the strictures of [Section 206]."[13] Accordingly, to change an existing rate, the Commission must find the existing rate to be unjust and unreasonable in a Section 206 proceeding before it may require the utility to file a new rate that will only take effect prospectively.[14] The Commission and the courts have recognized that FERC does not have authority to order a tariff filing outside Section 206 or to retroactively change a rate.

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[10] *See PJM Interconnection, L.L.C.*, 149 FERC ¶ 61,132 at P 1 (2014); *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,224 at P 5 (2015).

[11] *Atlantic City Elec. Co. v. FERC*, 295 F.3d 1, 9, 10 (D.C. Cir. 2002) ("*Atlantic City*") (citations omitted).

[12] *Public Serv. Comm'n of N.Y. v. FERC*, 642 F.2d 1335, 1345 (D.C. Cir. 1984) ("*NYPSC*").

[13] *NYPSC*, 642 F.2d at 1345. *See also, e.g., Public Serv. Comm'n of N.Y. v. FERC*, 866 F.2d 487, 488–89 (D.C. Cir. 1989) ("On four occasions in the last three years this court has reviewed Commission efforts to compromise § 5's limits on its power to revise rates. On each the court has repelled the Commission's gambit. This is number five."); *Western Res., Inc. v. FERC*, 9 F.3d 1568, 1578 (D.C. Cir. 1993) ("We now make it an even six.").

[14] *See, e.g.*, 16 U.S.C. § 824e; *Atlantic City*, 295 F.3d at 10.

Moreover, the Commission is only permitted to make very limited retroactive changes in accordance with Section 206(b) of the FPA, which allows the Commission to establish a refund effective date no earlier than the date of the filing of a Section 206 complaint or initiation of a Section 206 proceeding by the Commission.[15] These provisions of the FPA also address regulatory protocols, including allocations of burdens of proof, and rules against retroactive ratemaking. Therefore, any Commission action undertaken as a result of the workshop should adhere to these statutory requirements, rather than promote a perception that generators have violated the FPA by not making filings to change their rates under Section 205.

The FPA and NGA provisions accept that facilities will change over time and provide clear options for all parties. Clearly, generation facility operation will change over time, as will ownership for generation assets with long-lives that are capable of producing reactive power. The aforementioned PJM cases suggest there is a concern on the part of Commission Staff that a supplier may have continued to receive payment for units that were no longer capable of providing reactive service. Moreover, those cases presuppose that a reactive supply revenue requirement set out in a supplier's fleet-wide rate schedule is linked to particular units or to a particular amount of reactive power capability. However, the Commission has accepted black-box settlements that

[15] *See* 16 U.S.C. § 824e (2012). Indeed, but for Section 206(b), no retroactive effect would be permitted at all and even the refund permitted under Section 206(b) is very limited and requires prior notice. *See, e.g.*, *Exxon Mobil Corp. v. FERC*, 571 F.3d 1208, 1211-12 (D.C. Cir. 2009) (explaining that provisions of the FPA "generally limit the relief FERC may order to prospective remedies," and Section 206(b) provides "a narrow exception to the limitations imposed by these rules" by allowing the Commission to "order a refund of overcharges paid during a limited time period that begins after the filing of a complaint"); *id.* at 1215 (stating that "'refunds of any amounts paid' outside of the refund period are forbidden" and that "under section 206(b), FERC cannot order utilities to give back money already collected (except for money collected during the limited refund period)" (citation omitted)).

establish fleet-wide reactive rates that do not assign a rate to specific units, or state a rate in terms of a specified amount of reactive service.[16] Such cases demonstrate the challenges in attempting to attribute an increment of the revenue requirement to a specific unit or amount of reactive supply capability, and that there is no basis for now asserting that a supplier's fleet-wide revenue requirement established in a fleet-wide rate is tied to any particular unit.

In instances where a supplier is still capable of providing reactive supply, EPSA does not believe that changes in the composition of its fleet, including unit deactivation, cause its reactive power revenue requirement to become unjust and unreasonable. Similar to cost-of-service rates for electric transmission providers and natural gas pipelines, fleet-based revenue requirements are established based on the composition of the provider's system at one point in time but can remain just and reasonable even as the system changes over time because service continues to be provided by the remaining system. In fact, the Commission and the courts have long recognized that gas pipelines and electric transmission systems evolve over time, but that this does not require changes to existing rates.[17] Similarly, the fact that a reactive power supplier's

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[16] *See, e.g.*, Open Access Transmission Service Tariffs of Public Service Electric and Gas Company, Transmittal Letter at 4, Docket No. ER96-1320-000 (filed Mar. 15, 1996); Offer of Settlement, Appendix A at 2, Docket No. ER96-1320-000 (filed Aug. 8, 1996) (citation omitted); *id.*, Appendix B, Original Sheet Nos. 69, 72; *Public Serv. Elec. & Gas Co.*, Docket No. ER96-1320-000 (Nov. 28, 1997) (unreported) (accepting offer of settlement); Open Access Transmission Tariff of Baltimore Gas and Electric Company at Schedule 2, Docket No. OA96-156-000 (filed July 9, 1996); Offer of Settlement of Baltimore Gas and Electric Company, Attachment A, Section C, Docket No. ER97-3189-002 (filed Mar. 27, 1998); *Baltimore Gas & Elec. Co.*, Docket No. ER97-3189-002 (Sept. 18, 1998) (unreported letter order) (accepting offer of settlement).

[17] *See, e.g.*, *American Pub. Gas Ass'n v. FPC*, 567 F.2d 1016, 1057 (D.C. Cir. 1977) ("The common law of public utility regulation pragmatically accepts the futility of embroiling current and future rate regulation with a function of making correctives for excess or insufficiencies of rates charged in the past." (citation omitted)); *Columbia Gas Transmission Corp.*, 93 FERC ¶ 61,064 at 61,176 (2000) (the Commission "routinely allows pipeline facilities to be abandoned in between rate cases without requiring

fleet may change over time does not automatically mean that its rates are unjust or unreasonable. Nonetheless, to the extent the Commission or third-parties believe that the existing rate is no longer just and reasonable, such party can pursue a rate change pursuant to Section 206 of the FPA.

As with the gas pipeline situation, there are any number of reasons why fleet-based reactive power revenue requirements can remain just and reasonable even though units that were in service when the initial rate was established may have been taken out of service over time. For example, the costs of the remaining units in the fleet may have increased, substantially in some cases, since the acceptance of the revenue requirement. Also, there may have been plant additions, modifications or increases in operating and maintenance costs. In addition, while certain units in the fleet may have retired, the supplier may have also added new units without having made filings to update its revenue requirements. Moreover, there is no reason to assume that the fleet-based revenue requirement reflected the supplier's full cost of service when it was filed in the first instance or that intervening policy changes would not have justified a higher revenue requirement had they been in effect at the time.

C. Use of Nameplate Rating Compared to Test or Alternative Data

As discussed above, the AEP methodology provides compensation based on the

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the pipeline to re-justify or re-state its base rates to reflect the removal of the costs associated with the abandoned facilities" (footnote omitted)); *El Paso Natural Gas Co.*, 82 FERC ¶ 61,006 at n.11 (1998) ("in the context of spinning off gathering facilities, the Commission has authorized such spins offs even though the pipeline's existing rates are based on a cost of service including the costs associated with the facilities to be transferred. Existing shippers will not see a reduction in their rates, if any, due to a reduction in the cost of service until sometime in the future when the pipeline files its next general rate case"); *Kern River Gas Transmission Co.*, 80 FERC ¶ 61,399 at 62,325 (1997) (the Commission "does not require the pipeline to adjust its rates each time new facilities are constructed and/or throughput increases" and "does not consider it a violation of any rate condition if a pipeline's throughput increases between rate cases" (footnote omitted)).

owner's investment in reactive producing capability, which is measured on a nameplate basis. Importantly, the AEP methodology is an *investment*-based approach that has an annual revenue requirement, rather than a rate for an increment of reactive supply. Despite the AEP methodology not being tied to any consideration of production in the past, recently the Commission has been requiring testing data to accompany filings pertaining to reactive revenue recovery which utilize the AEP methodology. The workshop discussion suggests that this is new requirement is due to a perception that the test results show degradation, therefore indicating that reactive rates should be lower.

EPSA believes that while it may be appropriate to rely on test data to measure whether degradation in reactive producing capability has occurred, it is not appropriate to use such alleged degradation in production to change the set reactive compensation received by suppliers. First, as noted above, the FPA generally prohibits retroactive ratemaking and only permits the Commission to change existing rates through a Section 206 complaint proceeding. Second, cost-based rates are based on the cost of the equipment and capability to provide a product. These costs do not vary regardless of whether the machine produces nameplate output or less than nameplate output. Stated otherwise, the use of a nameplate rating as an allocator of original costs associated with the production of reactive power remains valid under the AEP methodology even if the unit does sustain some degree of degradation over time. The suggestion that payments for reactive power could be reduced because there is degradation in reactive power capability would wrongly treat the nameplate rating as a performance guaranty instead of the cost apportionment determinant it is designed to be.[18]

Third, from the standpoint of administrative practicality and fairness, EPSA believes that the drawbacks of using test data to set or inform compensation far outweigh those of using nameplate capability. Moreover, the use of nameplate capability better provides just and reasonable rates for reactive supply for the reasons enumerated below.

Test results are affected by several external and internal operational limitations, and do not reflect actual operations for provision of reactive supply. Bob O'Connell made this point clearly at the workshop: "We don't have these central generating stations in a lab where we can set up pristine conditions necessary to do tests."[19] The RTO/ISO panelists concurred that while they attempt to test during times of high demand, it does not always replicate periods of reactive provision and often does not include all units that provide reactive.[20]

Other drawbacks with respect to test data include:

- Tests normally cannot be conducted during conditions which reflect circumstances in which reactive is needed or would be called. For valid reasons, tests are prohibited from being conducted during emergency conditions when maximum reactive output is most likely to be needed and produced.

- PJM E-Dart data suffers from similar deficiencies to test data to the extent major local voltage events have not occurred during the period the Commission selects for reviewing the data. Fortunately, such major excursions rarely occur.

During the workshop, Commission staff questions suggested that the

[18] The performance obligations of the unit for reactive power services are generally set forth in the Interconnection Service Agreement.

[19] Video Archive for FERC June 30 Workshop, http://ferc.capitolconnection.org/063016/fercarchive_flv.htm

[20] *Id.*

consideration of nameplate rating versus test data to determine compensation was significantly impacted by concerns over generating unit degradation. EPSA panelist Levy addressed this point at the workshop, stating "It is an apples and oranges comparison. I think Mr. Williams of PJM agreed that test data was not perfect."[21] Test results reflect a specific point in time, and those results are affected by external operational limitations and internal operational limitations *caused* by external conditions that exist during that test period, such as temperature and humidity, generator or synchronous condenser voltage, auxiliary bus voltage, and system voltage limits. Accordingly, test results are ill-suited to measure the maximum amount of reactive power a unit can produce and to an extent explains why test results have not been previously used for compensation purposes by the Commission. The amount of reactive power that can be produced at the time of the test will be significantly affected by how much reactive power the transmission system can absorb *at that time*. When transmission system voltages are low, and reactive power is needed, more reactive power can be delivered. When voltages are higher, the ability of a unit to deliver reactive power to the system can be constrained by the transmission system voltage.

The following are some additional reasons why test data is not representative of the cost of providing reactive supply and does not appropriately align with unit degradation:

- In many if not most cases, test results that deviate from nameplate ratings occur for reasons unrelated to unit degradation.
- There is no evidence that degradation in reactive production capability, while possible, is a commonplace occurrence. In a typical generator, the same overall

[21] *Id.*

machine is used to produce reactive and real power. Thus to maintain capacity revenues, especially within the strict requirements of the Capacity Performance Mechanism in PJM, and to sell the maximum real power, unit owners already have appropriate incentives to maintain these machines to avoid output degradation.

- A cost-based methodology such as the AEP methodology employs levelized ratemaking, and thus undercompensates the generator in early years. If the Commission changes the compensation methodology later in the life of a unit to come in line with test data, it will be altering the investment reliance of the owner, which may never recover the full investment in the reactive producing portions of the machines, thus breaking the regulatory compact inherent in using a levelized rate approach.

- The AEP methodology is based on the dollars invested and has never before been based on the test results or day-to-day operations of units. Using an investment based model and layering on a production based approach will lead to unreasonable results. If the unit produces 70 percent of nameplate during a test, this does not mean that it should recover only 70 percent of its costs. If anything, the unit has become more expensive over time. This should not affect the cost recovery received in a cost-based ratemaking regime.

EPSA recognizes that there are many reasons that test data is different from the use of nameplate rating which do not have a specific relationship to the actual capability of a generator. In fact, these distinctions often form the basis for the differences between nameplate and test data and therefore should not be used to signify a degradation of a unit that in turn results in a need to reduce the revenue requirement.

II. CONCLUSION

WHEREFORE, EPSA believes adequate compensation for reactive supply is needed and critical in all RTO/ISO markets. The cost-based AEP Methodology is the best method to ensure ongoing investment in generation equipment necessary to provide sufficient levels of reactive supply. EPSA urges the Commission to ensure that all ISOs and RTOs provide sufficient compensation for reactive supply that supports the level of investment which will maintain sufficient resources capable of providing reactive power to ensure system integrity and reliability. This requires directing CAISO and SPP to develop a methodology to compensate generators for the provision of reactive power.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that I served an electronic copy of the foregoing pleading this July 28, 2016, upon each person designated on the official service list compiled by the Secretary in this proceeding.

/s/
Nancy E. Bagot, Senior Vice President