UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Indicated Generation Owners	)))	Docket No. EL19-70-000

COMMENTS OF THE INDEPENDENT MARKET MONITOR FOR PJM

Pursuant to Rule 211 of the Commission's Rules and Regulations,[1] Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor ("Market Monitor") for PJM Interconnection, L.L.C. ("PJM"),[2] submits these comments on the petition for declaratory order filed by certain generation owners ("Generators") initiating this proceeding ("Petition") (and the attached Affidavit of Michael R. Borgatti ("Borgatti Affidavit")).

Generators petition the Commission to determine (at 27), that the Commission establish a policy allowing "a generator to recover a reactive power revenue requirement based upon its full reactive capability." Generators would apply such policy even when sellers procure reactive capability that exceeds the level determined is needed by independent Regional Transmission Operators ("RTOs"). By "full amount," Generators apparently mean that they want to be paid for excess capability even when Generators intentionally incur significant costs to obtain that capability. Generators would then force the customers of the RTOs to pay those costs even when they exceed the RTO's

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1 18 CFR § 385.211 (2018).

2 Capitalized terms used herein and not otherwise defined have the meaning used in the PJM Open Access Transmission Tariff ("OATT"), the PJM Operating Agreement ("OA") or the PJM Reliability Assurance Agreement ("RAA").

determination of what is needed. The record in *Panda Stonewall, LLC*, reveals that a generator engaged in exactly this behavior.[3]

The issue raised is who gets to decide the reactive capability that transmission customers need for reliable service: the independent RTO or sellers. The conflict of interest in Generators' position is obvious. The cases cited by Generators ignore or circumvent the issue of who decides. One reason that issue has been ignored is that most cases are resolved through settlement proceedings with very limited participation, and such proceedings rotely apply *AEP*, a 1999 case that involved a traditional vertically integrated utility's accounting.[4] The RTO context is different. Regulation through competition is different. The treatment of reactive in the *AEP* method has never been properly adapted to the introduction of RTOs and RTO tariffs, and the replacement of cost of service regulation applied to vertically integrated utilities with competitive markets.

The best reform would be to eliminate cost of service reactive rates for reactive capability in PJM and similarly situated RTOs. This action could and should be taken in the proceeding initiated by the Commission in Docket No. AD16-17-000.[5] The comments filed here should apply only until the implementation of true market based reform. The comments filed here explain how the current approach could be improved, consistent with the public interest. In the current approach, the asserted costs of reactive capability are recovered under the *AEP* method in an awkward hybrid of market based rates and cost of service rates. The comments filed here concern how this inferior approach could operate so

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3 *See* Docket No. ER17-1821-000. An initial decision issued April 26, 2019. 167 FERC ¶ 63,010. Briefs on Exceptions are due June 12, 2019.

4 *See* American Electric Power Service Corporation, Opinion No. 440, 88 FERC ¶ 61,1411 (1999) (*AEP*).

5 *See* Comments of the Independent Market Monitor for PJM, Docket No. AD16-17-000 (July 27, 2016); Comments of the Independent Market Monitor for PJM [re workshop convened June 30, 2016], Docket No. AD16-17-000 (July 29, 2016).

as to avoid unjust and unreasonable treatment of PJM customers. At the very least, PJM customers should only pay for reactive capability that PJM independently determines is needed to operate the system reliably and PJM customers should not be required to pay for any portion of reactive capability twice.

Contrary to Generators' claims, no prior decision addresses whether Generators may force PJM customers to pay for more reactive capability than PJM determines is needed. No prior decision addresses how to ensure the reactive capability rates do not include compensation for capability that Generators have the opportunity to receive through the PJM Capacity Market.

Schedule 2 of the OATT assigns to PJM the independent authority to determine the reactive capability that it needs from generators. No prior decision states generators can be permitted in the course of submitting rate schedules pursuant to Schedule 2 to substitute their determination of what capability is needed for PJM's determination. Rate schedules filed under Schedule 2 of the OATT are filed as part of the PJM market design and cannot be properly evaluated except in that context. Such filings must properly coordinate with the rules that govern the PJM market design in order to be determined just and reasonable. RTOs exist to make independent, transparent and impartial decisions.[6] This case is a case of first impression, and it should be decided so as to preserve RTO independence and to protect the public interest. The unqualified phrasing requested by Generators should not be accepted. A properly qualified finding would be useful to the industry and at the same time protect the public interest.

The Market Monitor proposes that when cost of service rates are allowed for reactive capability in an organized wholesale market that relies on regulation through competition,

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[6] *See* Regional Transmission Organizations, Order No. 2000, FERC Stats. & Regs.¶ 31,089 (1999), order on reh'g, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000), aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish County, Washington v. FERC, 272 F.3d 607 (D.C. Cir. 2001).

the following policy apply: "a generator may recover a reactive power revenue requirement based upon its full demonstrated reactive capability, provided that the generator shows that the RTO has independently determined that such capability is needed for the reliable operation of the transmission grid and provided that no opportunity exists for the generator to recover the same reactive capability costs (or any portion of such costs) in RTO markets."

I. BACKGROUND

A. PJM Has the Responsibility to Procure Reactive Supply for Its Customers.

The OATT includes a modified form of Schedule 2 of the Pro Forma Tariff, which provides for the procurement of reactive capability.[7] Schedule 2 to the OATT defines PJM's responsibilities as transmission provider responsible for procuring reactive supply, including determining the "amount of Reactive Supply … that must be supplied with respect to the Transmission Customer's transaction … based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider." Schedule 2 further provides that PJM "administer the purchases and sales of Reactive Supply."

As the Transmission Provider, PJM must ensure that it has sufficient reactive supply (MVAr) to reliably operate the system. Some reactive capability is provided by transmission assets, such as capacitors. Procurement of capacitors and similar transmission system

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7 Petitioners cite (at 31) *Calpine Oneta*, 116 FERC ¶ 61,282 at P 28, in apparent effort to suggest there is a dispute concerning whether rates for rates for reactive capability concern something other than reactive capability. This a red herring. There is no factual dispute on this point. Generators are compensated for providing reactive power to meet PJM's operational needs under lost opportunity cost provisions. *See* OA Schedule 1 § OA Schedule 1 §§ 3.2.3, 3.2.3A, 3.2.3B. The issue is who determines the level of reactive capability that PJM customers need: PJM, who has the responsibility to operate the grid, or Generators who do not have such responsibility and are conflicted.

equipment is performed through the PJM regional transmission expansion planning process.

Reactive supply is provided by all generating resources as part of normal operations. The amount of this reactive supply is determined by PJM and secured by specifying a voltage schedule within which the unit must operate. Reactive capability is the ability of a unit to supply reactive power outside its normal operating range to remediate abnormal or emergency grid conditions. It is the responsibility of the TO to ensure grid security by specifying reactive capability and PJM does this (based on engineering analysis) by specifying both voltage control and reactive capability as a condition of interconnection. Generating units produce and absorb MVAr as needed to maintain voltage at the appropriate level.

PJM is required to procure both reactive supply and reactive capability from generating resources on a nondiscriminatory basis. Rather than attempt to determine unit by unit how much reactive supply is necessary, PJM has established a requirement that all generating units have sufficient reactive capability, measured by a power factor, in order to receive interconnection service.[8]

The requirement is set at 0.95 leading to 0.90 lagging for synchronous units and at least 0.95 leading to 0.95 lagging for nonsynchronous units.[9] The requirement is consistent with Commission's Rules that specify a minimum power factor range of 0.95 leading and 0.95 lagging power factor unless the market operators' rules specify otherwise.[10] The

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8 *See* OATT Part IV and VI & Attachment O § 12.0; *see also* PJM Manual 14-D § 5.2.1.

9 *Id.*; OATT Attachment O § 12.0.

10 See 18 CFR § 35.28(f)(1); see, e.g., Standardization of Generator Interconnection Agreements and Procedures, Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 542 (2003), pro forma Large Generator Interconnection Agreement (LGIA) § 9.6 & Appendix G, pro forma Small Generator Interconnection Agreement (SGIA) § 1.8 & Appendix G, which can be accessed at: <https://www.ferc.gov/industries/electric/indus-act/gi/stnd-gen.asp> .

Commission has recently extended the interconnection service reactive capability standard to wind and solar units, which previously had been exempt.[11] PJM confirms that the reactive capability interconnection requirement constitutes PJM's determination of the requirement for reactive supply pursuant to Schedule 2 of the OATT.[12] Any compensation outside the capacity payment is double recovery, e.g. paying for both real power capability (ICAP plus reactive capability of .90 lagging to .95 leading) and reactive power capability.

The lagging power factor at maximum output is widely accepted as the measure of a unit's reactive capability.[13] As a result, this power factor is incorporated in the allocation factors for reactive and thus the revenue requirement for reactive capability.

PJM must test units to obtain an accurate measurement of the reactive power that can be delivered by a generating unit.[14] PJM relies upon tests, conducted under normal system operating conditions, to populate its database on the reactive capability of units made available to system operators.[15] The nameplate rating for a generator does not indicate the reactive capability of a generator once that generator is interconnected at a

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11 *See Reactive Power Requirements for Non-Synchronous Generation*, Order No. 827, 155 FERC ¶ 61,277 (2016).

12 *See* Certification of Initial Decision and Record, ER17-1821-002 (April 29, 2019), IMM-006, included as Attachment A.

13 PJM Manual 14D (Generator Operational Requirements) Attachment D at 114 ("MW value at point 7 should be equal to the typical maximum economic output of the unit.").

14 *See* PJM Manual 14D (Generator Operational Requirements) § 7.3.4 & Attachments D & E, Rev 44 (June 1, 2018).

15 *See id.* PJM determined in 1999 that nameplate MVAR and power factor ratings do not reflect the value to the system operator of a units' reactive output after it is interconnected at a specific location. In response to a 1999 low voltage event, PJM performed a root cause analysis. The analysis concluded that "PJM narrowly avoided a voltage collapse" and the "if PJM had realized that the MVAR reserves that the EMS indicated were available were not realistic, other action could have been take [sic] to stabilize the system." PJM State & Member Training Dept., Slides, Reactive Reserves and Generator D-Curves at 13 (included as an Attachment), which can be accessed at: <*http://www.pjm.com/~/media/training/nerc-certifications/gen-exam-materials/gof/20160104-reactive-reserves-and-d-curve.ashx*>.

particular location on the grid.[16] The measure of reactive capability useful to system operators during normal system operations depends upon its location on the grid. System operators typically cannot match a nameplate rating, if such rating was ever reliable in the first instance, due to system limitations. Those same limitations mean that nameplate ratings are not useful to system operators. The Commission has acknowledged this issue in the *Wabash* decision and has stated a preference, if not a requirement, for reliance on tests rather than unreliable nameplate ratings.[17]

The output of a generator can be measured as its apparent power (MVA) which is the root mean square of its real power (MW)[18] and reactive power (MVAr). PJM dispatches a unit for its real power and requires it to operate within an agreed voltage schedule. When dispatched, the unit produces reactive power in accordance with the voltage schedule. The less reactive power the unit produces, the greater its real power output.

If PJM backs down a generator's real power output (MW) to obtain greater reactive power output (MVar), or dispatches a generator for its reactive power output, PJM compensates the generator based on lost opportunity costs, i.e. the reduction in real power times the LMP it would have received.

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16 *See id.*; Generators' Witness Borgatti observes (at para. 30) that "Nameplate represents the project's maximum rated capability" does not go the actual issue, which concerns the unit's actual capability. Actual capability cannot be determined until the unit is installed and the unit is tested in normal system operations and subject to local system limitations. Customer should not be required to pay for reactive capability based on speculative assertions of its maximum potential. Compensation is unjust and unreasonable for any level of reactive capability that has not been demonstrated and is not shown to be used and useful to PJM or its customers at the particular location where the unit is installed. If the location of a unit and its actual capability is ignored there is no incentive, as far as reactive capability influences the decision, for developers to select an efficient location. Regulation through competition and the PJM market design relies on efficient market based investment decisions.

17 *Wabash Valley Power Association, Inc.*,154 FERC ¶ 61,246 (2016).

18 Note that real power is sometimes called "active power" also sometimes called "working power."

The power factor states how apparent power capability is apportioned between reactive power and real power. A unit operating at a 0.9 power factor means that for every 1.0 MW of real power delivered to the grid it must produce 1.11 MWA of apparent power (and is also delivering .484 MVAr of reactive power).[19] System operators need to know this relationship in order to send accurate dispatch instructions. Units are tested to determine their reactive power output during normal system operations.[20] The results are entered in eDART so the PJM dispatchers know how much reactive power they are bringing on when they schedule real power on the grid. The power factor has no effect on obligations. The power factor should not affect total compensation for total generator capability.

As a condition of interconnection, generators are required to have many controls and capabilities. No special nonmarket compensation should be provided for having these controls and capabilities. The costs to include these controls and capabilities constitute part of the cost of capacity that generators must incur in order to receive interconnection service from PJM and to participate in PJM markets. One required capability that a generator is expected to provide is operation at a power factor of "at least 0.95 leading to 0.90 lagging" measured at the point of interconnection.[21] Unlike other costs of capacity, the OATT, following the approach in the Pro Forma Tariff designed prior to PJM's implementation of competitive markets, allows generators to file cost of service rates for capability. No

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[19] PJM usually does not require units to operate at 0.9 power factor. Usually they operate in the 0.96 to 0.99 range. At a PF of 0.96, a dispatch of 1 MW of real power requires 1.042 MVA of apparent power. At a PF of 0.99, a dispatch of 1 MW of real power requires only 1.01 MVA of apparent power.

[20] Normal system operations means operating within the normal voltage schedule determined by PJM or the TO. As a condition of interconnection all generators must have automatic voltage regulators to ensure compliance with the voltage schedule. *See* OATT Part IV and VI & Attachment O § 12.0; *see also* PJM Manual 14-D § 5.2.1.

[21] OATT Attachment O § 12.0. Note that nonsynchronous generators have a slightly different requirement. This pleading mostly refers to the standard for synchronous generators, but same principle applies for non-synchronous generators.

plausible rationale for singling out this particular requirement to obtain interconnection service for special compensation has ever been provided.

PJM typically has no reason to request and does not typically request a generator incur greater cost and agree to provide a greater capability than 0.90 power factor.[22] The Market Monitor is not aware that PJM has ever made such a request. It is not acceptable for a generator to incur greater costs and impose those costs on PJM customers with no determination from PJM that greater reactive capability is needed.

The concern is not theoretical. Panda Stonewall witnesses testified that Panda Stonewall deliberately designed and constructed a generating unit with a 0.85 power factor, and that by doing so, Panda Stonewall incurred increased costs compared to what it would have incurred if it had instead opted for a 0.90 power factor.[23] Through its reactive rate filing, Panda Stonewall sought to pass the costs of that decision to PJM customers. Accepting Generators' request leaves nothing to prevent developers from investing in even greater reactive capability and imposing the resultant greater cost on ratepayers and increasing their own guaranteed cost of service revenues.

B. The *AEP* Method Concerns the Allocation of the Same Fixed Costs Incurred to Build a Generator Between Two Cost of Service Rates.

1. The *AEP* Method Was Developed under Cost of Service Ratemaking.

Order No. 888, issued April 24, 1996, sought to remove impediments to competition in the wholesale bulk power marketplace, and to bring the benefits of efficient markets in

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22 Even under emergency conditions (Heavy Load Voltage Schedule Action/Warning) when resources are required to increase their reactive power output voltage levels, reactive power output is still to be maintained within predetermined limits. *See* PJM M-13 (Emergency Procedures) rev. 70 (May 30, 2019) at 87.

23 *See* Certification of Initial Decision and Record, ER17-1821-002 (April 29, 2019), Exh. PS-034 at 21 n.1; Exh. IMM-004 at 50:7–11, Included as Attachment B-1 & B-2.

the form of lower cost power to electricity consumers.[24] Order No. 888 required transmission owning public utilities to file open access nondiscriminatory transmission tariffs that contain minimum terms and conditions of nondiscriminatory service.[25]

PJM competitive wholesale power markets with competitive offers were implemented on April 1, 1999. The current form of the PJM Capacity Market began with the implementation of PJM Reliability Pricing Model (RPM) capacity market June 1, 1997.

Order No. 888 included a Pro Forma Open Access Transmission Tariff that specified six ancillary services.[26] One such service is "Reactive Supply and Voltage Control from Generation Sources Service." The Commission explained that reactive supply must be "offered as a discrete service, and to the extent feasible, charged for on the basis of the amount required."[27] The Commission also stated that including reactive supply as a separate ancillary service "may contribute to the development of a competitive market for such service if technology or industry changes result in improved ability to measure the reactive power needs of individual transmission customers or the ability to supply reactive supply from more distant sources."[28]

On April 2, 1993, American Electric Power Service Corp. ("*AEP*") filed an open access transmission tariff that included a rate for reactive supply and voltage control.[29] The Commission accepted AEP's explanation that "since generator/exciters and an allocated

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24 *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036, 61 Fed. Reg. 21,540, 21,541 (May 10, 1996) ("Order No. 888").

25 *Id*.

26 *Id*. at 21,597–617 & Appendix D ("Pro Forma Tariff").

27 *Id*. at 21,722.

28 *Id*. at 21,581–82 & n.359.

29 *See* Docket No. ER93-540.

portion of accessory and electric equipment produce active and reactive power, 'it was necessary to arrive at an allocation factor to segregate the reactive (VAr) production function from the active power (Watt) production function.'"[30] The allocation approach developed by AEP and its sponsoring witness Bernard M. Pasternak has become known as the *AEP* method. In that case, both the allocated costs of real power and the allocated costs of reactive power were recovered from customers under cost of service rates.

The *AEP* method recognizes that the same equipment used to produce real power (Watt) supporting energy, ancillary services and capacity sales is used to produce reactive power (VAr) supporting reliable transmission system operations. In the *Panda Stonewall* case, witnesses for the generator confirmed in the record the same equipment is used to produce real power and reactive power.[31]

There is no evidence in this proceeding that any original equipment manufacturer (OEM) sells generating equipment without reactive power capability.

2. Generators Should Not Be Allowed to Recover Reactive Capability Costs to the Extent that They Have the Opportunity to Recover Such Costs Through Other Markets or Rates.

Generators in PJM operate under market based rate schedules.[32] The costs of power production equipment are recoverable under market based rates for energy, capacity and ancillary services. Generators' statement (at 10) "Reactive power is not currently compensated through the Commission's energy, capacity or ancillary services markets" is false. Generators do not appear to understand how the *AEP* method interacts with PJM markets. In PJM, 100 percent of the costs of generating equipment is included in gross

30 *See American Electric Power Service Corporation*, Opinion No. 440, 88 FERC ¶ 61,1411 (1999) (*AEP*) *mimeo* at 29, citing AEP Initial Brief at 37.

31 *See Panda Stonewall, L.L.C.*, Docket No. ER17-1821-000, Tr. 1511:12—14.

32 *See*, *e.g.*, *Panda Stonewall L.L.C.*, Docket No. ER16-2643-000 (Nov. 28, 2018) (delegated order).

CONE. There is an offset to gross CONE based on energy and ancillary services markets. The result is net CONE. The offset includes a defined number for reactive, $2,199 per MW-year. The costs of reactive power in excess of $2,199 per MW-year are recoverable in the PJM Capacity Market.

Market based rates neither guarantee recovery of costs nor limit recovery to costs. Costs do, however, play an important part in determination of key market design parameters and the rules for mitigating the potential exercise of market power.

The *AEP* method was introduced in order to allocate costs between two cost of service based rates, one for generation and one for reactive. The *AEP* method used standard cost of service allocation methods to achieve this objective. Such cost of service allocations are performed because 100 percent of the total defined costs are allocated to customers, and recovered through cost-based rates.

The *AEP* method was not designed or intended to allocate costs between a cost of service rate and market recovery. Nevertheless, the cost of service approach used in Schedule 2 of the Pro Forma Tariff has been included in the PJM market rules. The precedent developed in *AEP* for allocating reactive costs between different cost of service rates has been applied in PJM, mostly in nonbinding settlements, even though PJM relies on market based rates and not cost of service rates for energy, capacity and other ancillary services. No sound rationale has ever been provided for including cost of service reactive rates in the PJM market rules or for applying the *AEP* allocation method to the development of such rates. There is no reason to presume that any rationale exists.

II. COMMENTS

A. The Issue of How Schedule 2 Operates Is One of First Impression.

The petition implicates how Schedule 2 must operate within the PJM market design. Schedule 2 must be applied with proper regard for the goals and objectives of independent RTOs. Generators cite no case that contradicts the Market Monitor's position that Schedule 2 specifically provides for PJM to determine the reactive capability that PJM customers need. It follows that the rate schedules filed pursuant to Schedule 2 should not be approved to the extent they are calculated in a manner inconsistent with PJM's determinations. This issue has been neglected and ignored, but that is no reason to disregard it now that it is squarely presented by Generators here and in the *Panda Stonewall* case. Generators rely on the failure to address this issue in past decisions. This proceeding provides an opportunity to correct the oversight so that Schedule 2 of the PJM tariff is implemented as filed and the public interest is protected. The development of RTOs and organized competitive markets is a significant development, and the policies developed in *AEP* should be adapted to the introduction of independent RTOs. AEP was a vertically integrated utility controlling both the generation function and the transmission functions. AEP was subject to comprehensive cost of service regulation.

B. Current Case Law Does Not Prevent PJM from Determining the Level of Reactive that Its Customers Need.

Most cases filed under Schedule 2 are resolved through settlements, although customers for whom reactive power is procured are generally not party to such settlements and the interests of customers are generally not represented in settlement proceedings. Settlements of Schedule 2 proceedings usually are approved as a black box. Black box settlements are accepted without any consideration of the facts or law, and they do not set precedent. PJM often intervenes in such proceedings but does not participate. Under such circumstances, it is unsurprising that the issue of whether Schedule 2 has been properly interpreted and applied has not come up. This means that for over a decade practices have taken hold without reflection. In the meantime, dramatic changes in how the industry is regulated and organized have occurred, with no serious reevaluation of the regulatory approach. In this proceeding, the policies concerning how reactive capability is procured and compensated should receive needed attention based on accurate assessments of the facts, the existence of organized markets and the market rules and design prevailing in those markets.

Petitioners claim that *American Transmission Systems, Inc.*, 119 FERC ¶ 61,020 at PP 15, 27 (2007) ("MISO/ATSI Order"), resolves the issue. The MISO/ATSI Order does not address the Market Monitor's argument and would not set precedent if it did.

First, the MISO/ATSI Order concerns the Midwest Independent System Operator, Inc. and its tariff, not PJM Interconnection, L.L.C. and the PJM OATT. The Commission determined to approve a settlement using a nameplate factor instead of requiring use of the applicable interconnection standard for two reasons, neither of which applies in this case.

First, the Commission found no rationale for using the applicable interconnection standard. Here, the Market Monitor offers a compelling rationale: PJM and not a generator has the responsibility in the PJM OATT to determine the amount of reactive capability PJM needs, and that level is 0.90. There is no rationale for allowing a generator to usurp PJM's role in determining the level of capacity the PJM transmission system needs. The Market Monitor offers a clear and simple rationale to preserve PJM's proper role: Allowing a generator to determine the level of capability it needs creates a perverse incentive to invest in more reactive capability than needed.

The *Panda Stonewall* case shows that the Market Monitor's concern is not theoretical. Panda Stonewall witnesses testified that they consciously chose to obtain a higher power factor at increased cost with no discussion or involvement from PJM.[33] They point to the 0.85 power factor as contributing to a significant increase in cost for Panda Stonewall above other similar projects sponsored by the company.[34] Accepting Panda Stonewall's argument leaves nothing to prevent it or other developers from investing in even greater reactive capability and imposing the resultant greater cost on ratepayers and increasing their own guaranteed cost of service revenues.

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[33] See IMM Init. Br. at 25–26.

[34] See *id*.

Second, the Commission explained its own rationale:

> Because a generator has the ability to produce reactive power up to its nameplate capability, and because it is obligated to do so to prevent or respond to emergency situations, [footnote omitted] there is no rationale that would warrant using anything less in determining a generator's reactive power capability.[35]

The concern is that if MISO uses capability, then MISO should pay for use of that capability. The Commission concern does not apply in PJM because MISO uses cost of service rates to cover all generators' fixed costs while in PJM, a hybrid method is used incorporating both cost of service rates for reactive and markets. The Commission cited to a provision in this particular settlement agreement that detailed the obligation.[36]

The rationale offered in *ATSI* does conflict with Petitioners' position. *ATSI* says that compensation for reactive capability should track obligation to provide reactive capability. Petitioners here request a determination that they are entitled to be compensated on the full reactive capability of the generator even if such capability exceeds their obligations to PJM.

Finally, assuming the passages cited in the MISO/ATSI Order have any relevance at all to the circumstances in PJM or other markets, they are at most dicta, not precedent. The settlement was approved under the criteria for evaluating contested settlements in *Trailblazer Pipeline Company*.[37] Under *Trailblazer*, a settlement may be approved if the "settlement as a whole, considering not just the contested issues, but the uncontested issues as well, provides a just and reasonable result."[38] The Commission has approved black box

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35 MISO/ATSI Order at PP 25–27.

36 *Id*. at P 27 n.23.

37 *S*ee Trailblazer Pipeline Company, 85 FERC ¶ 61,345 (1998), order on reh'g, 87 FERC ¶ 61,110 (1999), reh'g denied, 88 FERC ¶ 61,168 (1999).

38 85 FERC ¶ 61,345 mimeo at 25.

settlements under the *Trailblazer* criteria when the record is devoid of support for particular inputs or terms.[39] Generators' argument exclusively relies on discussion from a decision without binding force. The Commission may resolve this issue as a matter of first impression.

C. Reactive Power Rates Should Coordinate with Other Features of the RTO's Market Design, and Should Not Permit Double Recovery of Investment in a Generators' Capability.

1. Reactive Capability Rates That Exceed the Reactive Rates Offset in the Capacity Market Double Recover Costs from Customers.

An order responding to this petition should also condition recovery of the costs of reactive capability on the Generators' showing that Generators have no opportunity to recover those same costs through markets. Reactive capability rates filed within the PJM market design must respect and account for how that design operates. It is improper to evaluate reactive capability rates in isolation. Prohibition of double recovery is a requirement for just and reasonable rates. The PJM market rules are designed to avoid double recovery of reactive capability rates in the PJM capacity market. The PJM market rules explicitly account for recovery of reactive revenues through a cost of service rate of $2,199 per MW-year. Reactive capability rates up to that level, the "reactive rates offset," do not result in double recovery.

Reactive capability rates above the level of the reactive rate offset do result in double recovery because costs that would support a rate exceeding $2,199 per MW-year are recoverable in the PJM Capacity Market. Prior to the *Panda Stonewall* case, this issue was not raised in any proceeding under Schedule 2 of the OATT and the PJM market design.

To avoid double recovery, reactive capability rates in PJM should be capped at the level of the reactive rate offset.

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[39] See GenOn Power Midwest, LP, 149 FERC ¶ 61,218 at P 35 (2014).

Market Seller Offer Caps are directly affected by the treatment of reactive revenue. If there were no nonmarket recovery of reactive revenue, there would be no reactive revenue offset to net CONE and the default market seller offer cap would be higher. Unit owners could increase their offers to recover reactive capability costs if they believed that the offer would be competitive. If there were no nonmarket recovery of reactive revenue, the resultant higher offer cap would give unit owners the opportunity to recover all reactive capability costs in the capacity market.

This is how the capacity market works for all the other costs of a generating plant other than short run marginal costs.

If there were no ancillary services revenue offset, reactive costs would be entirely addressed in the PJM Capacity Market. Unit owners would have the ability to make a competitive offer including all the relevant costs of generation.

If there were no ancillary services revenue offset, the shape and location of the VRR curve would give unit owners the opportunity to recover all reactive capability costs in the capacity market.

The fact that there are two different regulatory approaches in the PJM Market Rules for recovery of the same costs does not change the result that double recovery occurs if rates under Schedule 2 are set higher than the $2,199 per MW-year offset.

The Commission has recognized the relevance of the issue associated with a "resource receiving cost-based rate recovery while concurrently receiving compensation for market-based rate services involves potential double recovery of costs borne by the relevant cost based ratepayers."[40] The Commission plainly states: "the potential for combined cost based and market based rate recovery to result in double recovery of costs" is an issue that

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40 *Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery*, 158 FERC ¶ 61,051 at P 15 (2017) ("Cost-Based Recovery Policy Statement"); *see also*, *Transwestern Pipeline Company*, 52 FERC ¶ 61,100 (1990) ("held that Transwestern could not file to recover costs incurred after market-based GIC rates were in effect").

"should be addressed."[41] The Commission has evaluated solutions, including but not limited to, "crediting any market revenues back to the cost based ratepayers."[42] The Commission stated its general policy: "Any solution would need to comport with cost of service precedent."[43]

The Commission further identified the need to tailor a solution to cases where there is a full or partial double recovery:

> [T]his market-revenue offset can be used to reduce the amount of the revenue requirement to be used in the development of the cost-based rate. This up-front rate reduction would also help ensure that the cost-based rate remains just and reasonable and provide the electric storage resource owner or operator with an incentive to estimate market revenues as accurately as possible. In this scenario, the need for crediting of market revenues could be proportionally reduced as well. In other words, full cost recovery through cost-based rates may require full crediting of projected market revenues; no cost recovery through cost-based rates would require no crediting of projected or actual market revenues; and partial cost recovery through cost-based rates could require partial crediting of market revenues. For example, if the cost-based rate is based on 25 percent of the asset's full cost-of-service, then perhaps only 25 percent of market revenues would need to be credited to cost-based ratepayers.[44]

To date, generators filing for reactive capability rates make no attempt to reconcile the proposed cost of service rates with the concurrent opportunity for the recovery of costs

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41 *Id*. at P 13.

42 *Id*. at P 15.

43 *Id*. P 19, citing *The Nev. Hydro Co. Inc.*, 122 FERC ¶ 61,272 (2008) (at P 83: "allowing LEAPS to receive a guaranteed revenue stream through CAISO's [Transmission Access Charge] would create an undue preference for LEAPS compared to these other similarly situated pumped hydro generators"); *Western Grid Dev., LLC*, 130 FERC ¶ 61,056, *reh'g denied*, 133 FERC ¶ 61,029 (2010).

44 *Id*. at P 18.

in PJM markets. Generators behave as though rates filed under Schedule 2 do not require recognition for the rest of the PJM market design. The result is unjust and unreasonable rates for reactive capability, with customers paying twice for the same investment in reactive capability. The double recovery issue cannot properly be ignored, and the provision of PJM market rules that addresses double recovery, the $2,199 per MW-year offset, must factor into the determination of whether generators' proposed rates are just and reasonable.

In PJM, the allocation that results from the *AEP* Method is between cost of service rates for reactive power and market based rates for generators and all their costs. The PJM market rules explicitly account for the recovery of a defined amount of reactive costs under a cost of service rate. It is essential that the reactive costs recovered under the cost of service rates not exceed that defined amount. The balance of reactive costs is assigned to the markets. In the PJM market rules, successful application of the *AEP* method continues to depend upon a proper and nonduplicative allocation of costs between two rates.

In this case, no rate should be approved under one part of the PJM market design (OATT Schedule 2) that is inconsistent with the rest of the PJM market design. The Cost-Based Recovery Policy Statement recognizes (at P 19) that multiple options to address double recovery are possible. PJM has filed and the Commission has approved an approach including an offset that is not at issue here. This case takes that prevailing hybrid regulatory regime as it exists, but the need for a proper reconciliation of different regulatory approaches remains in order to ensure just and reasonable rates. Ignoring the problem creates an unjust and unreasonable result.

The PJM Market Rules provide for reconciliation between cost of service reactive rates and market rates by including a $2,199 per MW-year offset in market rates to account for the recovery of reactive costs through cost of service rates. Generators cannot show that a proposed rate filed under Schedule 2 is just and reasonable without also showing that the proposal is consistent with the existing PJM market rules. Generators cannot make such showing if the proposal conflicts with fundamental ratemaking principles prohibiting double recovery.[45]

Double recovery is a ratemaking concept that has traditionally been applied to a situation where there are two or more rates, both of which are calculated under the cost of service approach. That situation does not exist in PJM because most rates in PJM are a result of competitive prices determined in PJM markets.

With a cost of service rate, the cost number is defined precisely and the method of cost recovery is defined in accounting terms. With market based rates, unit owners have the opportunity to recover costs from the markets, but there is no defined revenue or cost number that must be recovered, or a defined accounting method for recovery. Double recovery exists when specific costs are included in a cost of service rate and the opportunity to collect the same costs exists under market based rates. The opportunity is explicitly built into the PJM capacity market design through the VRR curve and the net CONE offer cap.

Under market based rates in the capacity market, unit owners receive revenues but the revenues are not uniquely associated with specific elements of fixed costs. For example, if a unit receives $300 per MW-day in capacity market revenues during a delivery year, the revenue contribute to covering all fixed costs and cannot be identified as covering a specific element of fixed costs. This is particularly true for reactive costs as the same generating equipment produces both real and reactive power. If the unit's total costs are $400 per MW-day, the shortfall cannot be assigned to reactive fixed costs or all other fixed costs.

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45 *See, e.g.*, United Airlines, F.3d 122, 134 ("because FERC failed to demonstrate that there is no double-recovery of taxes for partnership, as opposed to corporate, pipelines, we hold that FERC acted arbitrarily or capriciously"); Cal. ex rel. Harris v. FERC, 784 F.3d 1267, 1276 (2015) ("Obviously, parties are not entitled to double recovery"); *see also Wabash Valley Power Association, Inc.*, 154 FERC ¶ 61,246 at P 24 (2016) ("Allowing recovery of fixed costs related to heating losses as part of the variable heating loss component would amount to double recovery of fixed costs for heating losses because those fixed costs are already included in the reactive power portion of the production plant investment."); *SFPP, L.P.*, 162 FERC ¶ 61, 228 (2018); *Inquiry Regarding the Commission's Policy for Recovery of Income Tax Costs*, 162 FERC ¶ 61,227 (2018)

When markets replaced cost of service regulation, the opportunity to recover costs replaced the accounting recovery of specifically identified costs. That fact makes actually demonstrating double recovery in an accounting sense impossible. But that does not mean that double recovery does not result when the same costs are in cost of service rates and recoverable in market based rates. Double recovery results by definition when the same costs are in cost of service rates and recoverable in market based rates.

The courts have not required mathematical analyses, but have instead addressed the theory and concepts.[46] The Commission has not rejected arguments about double recovery because they could not be quantified, but because the Commission did not agree that the conflict existed in the rules.[47]

PJM market rules provide for the opportunity to recover the costs of reactive power capability in two ways: through the definition of the demand curve for capacity and

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46 *See* United Airlines, 827 F.3d 122, 136 ("Despite their attempts to inundate the record with competing mathematical analyses of whether a double recovery of taxes for partnership pipelines exists, the parties do not disagree on the essential facts. First, unlike a corporate pipeline, a partnership pipeline incurs no taxes, except those imputed from its partners, at the entity level. [citation omitted] Second, the discounted cash flow return on equity determines the pre-tax investor return required to attract investment, irrespective of whether the regulated entity is a partnership or a corporate pipeline. [citation omitted]. Third, with a tax allowance, a partner in a partnership pipeline will receive a higher after-tax return than a shareholder in a corporate pipeline, at least in the short term before adjustments can occur in the investment market."). Consistent with *United Airlines*, the Commission has identified a double recovery between two components of a cost of service rate, where one component (DCF analysis) served as a substitute for estimated market revenues. *See SFPP, L.P.*, 162 FERC ¶ 61,228 at P 22 (2018) ("[T]he Commission finds that a double recovery results from granting an MLP such as SFPP an income tax allowance and a DCF ROE. This finding is based upon the following: MLPs and similar pass-through entities do not incur income taxes at the entity level. Instead, the partners are individually responsible for paying taxes on their allocated share of the partnership's taxable income.")

47 *PJM Interconnection, L.L.C.*, 158 FERC ¶ 61,133 at P 125 (2017) ("We also note that Additional Labor Costs are not allowed to be recovered through the ACR; therefore, we reject the IMM's argument that including these components in cost-based offers could raise market power concerns or create an unreasonable double recovery between the two markets.").

through the default market seller offer cap. This is exactly the same way that PJM market rules provide for the opportunity to recover all the costs of capacity resources.

One of the key parameters of the demand curve for capacity, the Variable Resource Requirement (VRR) curve, is the net cost of new entry or net CONE. Net CONE affects the location and shape of the demand curve for capacity and thus the clearing price for capacity. Net CONE equals the gross cost of new entry for the reference unit technology less the revenues from energy and ancillary services revenues that offset that cost. The energy market revenues are calculated based on the dispatch of the reference unit against historical locational marginal price (LMPs) for the last three years and the revenues for ancillary services (reactive only) are included in the tariff as a fixed number, $2,199 per MW-year.

The $2,199 per MW-year offset is a simple rule that established a just and reasonable reconciliation of different regulatory approaches in the same market design. The offset assumes that a defined level of revenues is received under cost of service rates. The offset reduces the opportunity to recover that level of costs in the capacity market. When the actual level of reactive revenue exceeds the $2,199 level, the actual reactive revenues are not reflected in the net CONE calculation or in capacity market offers and the net CONE calculation is too high by that difference and such offers are too high by that difference. Reactive rates cannot be just and reasonable if they do not account for the market design in which PJM units operate.

2. The PJM Hybrid Regulatory Approach Is Not an Excuse to Ignore Double Recovery.

The current PJM market rules provide for concurrent cost of service and market based regulation. The best approach would be to eliminate cost of service rates and rely on markets, but that is not an option in this proceeding. The Market Monitor instead advocates the only approach within the framework of the current rules that allows the hybrid regulatory approach to operate in a just and reasonable manner.

a. Full Overlap

Imagine two market designs. Under one market design, unit owners recover 100 percent of the capacity costs of generating units through cost of service regulation. The capacity costs are allocated to wholesale customers. Under the other market design, unit owners have the opportunity to recover 100 percent of the capacity costs of the same generating units through a capacity market. The capacity costs are allocated to wholesale customers. Both market designs provide unit owners the opportunity to recover 100 percent of their capacity costs.

Now imagine a wholesale market design in which both approaches to capacity costs are implemented.

Is there double recovery in this situation if both cost of service and the market are implemented in the same design?

Logically, there is double recovery. There is double recovery because there are two elements of the market design, both designed to provide unit owners the opportunity to recover 100 percent of their capacity costs.

There is double recovery not because unit owners would recover exactly the same amount under both approaches, but because unit owners have the opportunity to recover 100 percent of capacity costs under both approaches.

If annual capacity costs are $100 million, unit owners would expect to receive $100 million under cost of service regulation. Unit owners would expect to recover an amount less than, equal to or greater than $100 million under the market approach.

There would be double recovery if unit owners recovered zero capacity costs under the market approach, recovered $100 million under the market approach or recovered $200 million under the market approach. It is not necessary to demonstrate actual recovery of $100 million under the markets approach in order to demonstrate double recovery. The actual level of recovery under the market approach is irrelevant.

A logical wholesale market design would have one mechanism for capital costs or the other, but not two mechanisms, both designed with the same goal.

b. Partial Overlap

Imagine the same market design with one modification. In the new design, unit owners are allowed to recover only 25 percent of capacity costs through cost of service regulation. In the new design, unit owners still have the opportunity to recover 100 percent of the capacity costs of the same generating units through a capacity market.

Is there double recovery in this situation if both cost of service and the market are implemented in the same design?

Logically, there is double recovery, although less than in the first design. There is double recovery because there are two elements of the market design, one designed to provide unit owners the opportunity to recover 25 percent of their capacity costs and the other designed to provide unit owners the opportunity to recover 100 percent of their capacity costs.

There is double recovery not because unit owners would recover exactly the same amount under both approaches, but because unit owners have the opportunity to recover the same 25 percent of capacity costs under both approaches.

If annual capacity costs are $100 million, unit owners would expect to receive $25 million under cost of service regulation. Unit owners would expect to recover an amount less than, equal to or greater than $100 million under the market approach.

There would be double recovery if unit owners recovered zero capacity costs under the market approach, recovered $25 million under the market approach, recovered $125 million under the market approach or recovered $200 million under the market approach. It is not necessary to demonstrate actual recovery of $100 million under the markets approach in order to demonstrate double recovery. The actual level of recovery under the market approach is irrelevant.

c. Hybrid Approach

While a more logical, more efficient, more transparent and more easily administered wholesale market design would have one mechanism for capital costs or the other, but not two, both designed with the same goal, PJM has a hybrid design for legacy reasons. What would a logical hybrid design look like?

A logical hybrid design would reflect in the market approach that 25 percent of capacity costs are already collected through cost of service rates. The design of the market approach only has to provide the opportunity to recover 75 percent of capacity costs, or $75 million in this example. An essential point is that the division must be explicitly stated and that there must be an explicit recognition that the two parts of the design are different but must be made compatible. In this case, 25 percent of the capacity costs are assigned to cost of service regulation and 75 percent of the capacity costs are assigned to the market. In that case there would not be double recovery.

However, there cannot be a workable design that assigns an undefined share of capacity costs to cost of service regulation but 75 percent to the market. If 50 percent of costs for a unit owner were allowed to be recovered under cost of service regulation and 75 percent of costs were assigned to the market, there would be double recovery. While not as extreme as assigning 100 percent to both mechanisms, the logical issue is identical.

3. To Avoid Double Recovery Generators Should Be Required to Define Reactive and Real Power Capability Using Consistent Power Factors.

Another example of how the power factors approved in reactive power capability rates filed pursuant to Schedule 2 do not properly coordinate with the PJM market design is the inconsistent use of power factors. Generators routinely include reactive power capability in reactive capability cost of service rates using a power factor that inflates reactive power capability (MVAr), and sell capacity in the capacity market based on a different power factor that inflates the quantity of capacity available (MW). Both reactive power capability and real power capability cannot both be inflated simultaneously and remain accurate. To ensure accurate, just and reasonable compensation a uniform measure of power factor must be used.

Generators provide both real power and reactive power. The power factor measures the ratio of simultaneous real and reactive power output. The same power factor applies in both cases. Using one power factor (e.g., 0.85) for reactive power capability (MVAr) and a different power factor (e.g., 1.0) for real power capacity (MW) in combination overstates the total capability of the unit. The result is overpayment.

Generators should use the same power factor consistently in both calculations. If a generator indicates a 1.0 power factor to establish its installed capacity that will be used to determine the quantity capacity (MW) available for sale in the capacity market, then the same unit should indicate a 1.0 power when applying the *AEP* method to calculate its reactive power capability. If the numbers do not match and overstate the unit's capability, PJM customers will be charged twice for the same capability.

Commission policy should prevent unjust and unreasonable double recovery of costs from PJM customers, and any similarly situated customers in other markets. Generators should be required to use the same power factor to calculate reactive power capability and to calculate installed capacity.

D. The Approach to Cost of Service Rates Advocated by the Market Monitor Would Result in an Administrative Process that Better Serves the Public Interest.

One consequence of applying the cost of service approach to participants in competitive markets is that the Commission must either relax its standards for supporting cost of service filings or generators must incur significant expense to maintain and produce accounts and records that they would otherwise keep. Generators must reveal potentially commercially sensitive information in administrative proceedings.

The burden on the public posed by the cost of covering cost of service proceedings for reactive power is so great that customer interests for the most part go unrepresented and unprotected. Most such proceedings conclude in settlements including no one who pays or represents those who pay for reactive capability. Numerous settlements mean that rates are not specifically found just and reasonable, and the ability to ensure consistent treatment among participants who are otherwise competing in competitive markets is reduced. A key public interest in regulation through competition, the avoidance of expensive, difficult, complicated and burdensome administrative process, is unreasonably denied.

As a matter of common sense and good policy, the best course is to follow the Commission's approach when it began restructuring the industry and rely on markets to the maximum extent possible.[48] The markets have demonstrated that regulation through competition can sustain investment and provide power to customers at low cost.[49] The is no reason not to rely on markets to compensate generators for their capabilities, including reactive power capability, through the existing market design, particular in PJM with its fully functional capacity market. Consistent reliance on competition could be accomplished in PJM simply by eliminating the reliance on generator cost of service filings from Schedule 2 and eliminating the reactive power capability offset included in the capacity market design. This approach would eliminate the market distortions, establish a consistent and rational regulatory approach and remove unnecessary administrative burdens that derive from continued reliance on the awkward hybrid approach now used in PJM. Eliminating cost of service rates would contribute towards the Commission's longstanding goals for regulation through competition. There is an open docket, No. AD16-17, where the Commission could immediately take this productive step and streamline RTO regulation to serve the public interest.

In this proceeding, incremental improvements could still reduce the irrationality, expense and unfairness inherent in continued reliance on the existing hybrid approach. Requiring use of 0.9 power factor and prohibiting double recovery would significantly reduce the administrative burden of determining power factors.

Applying the measures here advocated by the Market Monitor would not only allow for a more just and reasonable coordination of PJM's hybrid approach for compensating

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[48] *See, e.g.*, Order No. 888.

[49] *See, e.g.*, 2018 State of the Market Report for PJM, Vol 1 (March 14, 2019).

generator capability, it would improve the efficiency and protect the integrity of the associated administrative process. If reforms under Docket No. AD16-17 are not pursued in the near term, this petition affords an opportunity to address in a simple statement of policy key deficiencies in PJM's current market design and potentially other RTOs so that the PJM market design operates in manner defensible as just and reasonable.

The Market Monitor recommends resolving this proceeding with issuance of the following statement of policy: "a generator may recover a reactive power revenue requirement based upon its full demonstrated reactive capability, provided that the generator shows that the RTO has independently determined that such capability is needed for the reliable operation of the transmission grid and provided that no opportunity exists for the generator to recover the same reactive capability costs (or any portion of such costs) in RTO markets."

III. CONCLUSION

The Market Monitor respectfully requests that the Commission afford due consideration to these comments as it resolves the issues raised in this proceeding.

Respectfully submitted,

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Dated: June 3, 2019

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Eagleville, Pennsylvania,
this 3rd day of June, 2019.

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Attachment A

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October 17, 2018

Via Electronic Mail

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RE: Panda Stonewall, LLC, Docket No. ER17-1821-002

Dear Mssrs. Mayes and Blair and Dr. Bowring,

Pursuant to Rule 406 of the Federal Energy Regulatory Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.406 (2018), enclosed please find the responses of PJM Interconnection, L.L.C. to the First Set of Data Requests of the Independent Market Monitor for PJM ("IMM") to PJM, dated October 9, 2018.

Please let me know if you have any questions.

Sincerely,

/s/ *Jennifer Tribulski*

Jennifer Tribulski
Associate General Counsel
PJM Interconnection, L.L.C

4. Schedule 2 of the OATT provides: "The amount of Reactive Supply and Voltage Control from Generation or Other Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider." What is the necessary amount of the Reactive Supply and Voltage Control Generation that PJM has determined must be supplied?

PJM Response:

As required by the PJM Open Access Transmission Tariff ("Tariff"), Parts IV and VI and the Interconnection Service Agreement (Tariff, Attachment O), an Interconnection Customer enters into with PJM and the relevant Transmission Owner, the Interconnection Customer for new synchronous generating facilities agrees to maintain a composite power delivery at continuous rated power output at a power factor of at least 0.95 leading to 0.90 lagging. For all new wind-powered and other non-synchronous generation facilities the Generation Interconnection Customer shall design its Customer Facility with the ability to maintain a composite power delivery at a power factor of at least 0.95 leading to 0.95 lagging across the full range of continuous rated power output.

Prepared By:

David M. Egan - Manager, Interconnection Projects

Attachment B-1

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Panda Stonewall LLC **Docket Number ER17-1821-002**

PREPARED DIRECT TESTIMONY OF EXPERT STEVEN M. WOFFORD

July 2, 2018

(summarized above) in support of a reactive power rate. For example, in Docket No. ER04-1075, 16.65% was used for the combustion turbine and 32% was used for the steam turbine. In Docket No. ER06-1131, 19.1% was used.

Q30. HOW DID YOU OTHERWISE ASSESS THE REASONABLENESS OF THE PERCENTAGE PROVIDED BY SIEMENS, AND WHAT DID YOU CONCLUDE?

To assess the appropriateness of the percentage provided by Siemens and used by Panda Stonewall, I also compared Panda Stonewall's percentage to the percentage used in other reactive power rate filings for similar-sized combined cycle units with the same power factor.[1] I did this since the filings I have done, and the percentages indicated above, are not for the same type of plant as Panda Stonewall. As the table below shows, Panda Stonewall's percentage is similar to and in fact lower than all of the percentages for comparable plants.

Plant	**Docket**	**Plant Size (MW)**	**Technology**	**PF**	**CT 1 %**	**CT 2 %**	**ST %**
Panda Stonewall	ER17-1821	778	2x1	0.85	[redacted]	[redacted]	[redacted]

[1] It is important to compare plants with the same power factor because the power factor rating affects the design and construction, and thus the cost of the generator/exciter. A unit with a power factor rating of .85 vs .90 will cost more due to material within the generator/exciter and cooling needs for the components.

CPV MD	ER17-481	725	2x1	0.85	21.9	20.1	26.5
Newark Energy	ER15-1706	702	2x1	0.85	17.82	17.82	24.62
Fayette	ER03-794	620	2x1	0.85	20.2	20.2	40.8
West Deptford	ER14-1193	715	2x1	0.85	19.5	19.5	19.2
CPV Shore	ER15-2589	775	2x1	0.85	21.9	20.1	26.5

While this is not a complete listing of all 2X1 combined cycle plants with a .85 power factor, I believe it is a reasonable sample set. Based on this assessment, and Panda Stonewall's use of the manufacturer's calculation, I concluded that the use of 13.5 percent was reasonable.

HEATING LOSS CALCULATION

Q31. HAVE YOU REVIEWED THE CALCULATIONS OF HEATING LOSSES FOR PANDA STONEWALL THAT WERE INCLUDED IN THE INITIAL FILING?

A. Yes.

Q32. WHAT IS YOUR OVERALL ASSESSMENT OF PANDA STONEWALL'S HEATING LOSS CALCULATIONS?

A. Because Panda Stonewall was not in service at the time of the filing, certain assumptions were made in the calculations in the original calculations. Based on my

Attachment B-2

Date: August 29, 2018

Case: In the Matter of: Panda Stonewall, LLC

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with providing the information.

Q Have you made efforts throughout this proceeding to seek information regarding Panda Liberty or Panda Patriot?

A I used a limited set of information from Patriot in the initial filing for Panda Stonewall.

Q In response to discovery requests, have you made efforts to secure information regarding Panda Liberty and Panda Patriot?

A I've provided the nonpublic version of Panda Patriot's filing. It was submitted in response to a discovery request.

Q Have you provided the nonpublic versions of either of those files?

A I think my answer was that I provided the nonpublic version of the Panda Patriot filing.

Q I'm sorry; you did provide the nonpublic versions?

A That's correct.

Q Is it safe to say then you had the legal authority to do that?

MR. MINZNER: Object on the same grounds

as asking the witness about his legal authority.

BY MR. JONES:

Q You still may answer.

A I'm not a lawyer, so I can't talk about the legal authority. I had the authority to do so.

Q Do you recall what the revenue requirement was for Panda Liberty?

A Are you asking for the initial request?

Q I appreciate the clarification. I did say "was." What was the revenue requirement that you filed for, if you recall, and what is the one currently being received in rates?

A The initial request was for a little more than $2.4 million.

Q And do you recall that case settled; is that correct?

A That's correct.

Q And the settlement revenue requirement, I guess that would be the rate on file currently. Do you recall what that is?

A Yes, it's 1.94 million.

Q And are those numbers also do those track over -- are they identical for Panda Patriot?

A No, the Panda Patriot is slightly different. The initial request for Panda Patriot was a little bit more than $2.3 million and the settled value was $1.9 million.

Q Can you help me understand what about the technologies of those two facilities, in comparison to Panda Stonewall, leads Panda Stonewall to have a revenue requirement that is roughly three times that of the two other plants?

A I'm not sure where you want to go with this question. If you're asking me for the technical differences, I'm not a gas turbine engineer, so I can't get into the technical differences between the engines between the Panda Patriot and Panda Liberty versus Stonewall.

At a high level, the Panda Patriot and Panda Liberty are two one-by-one combined cycle units. Panda Stonewall is a two-by-one combined cycle unit.

Q And you sponsored all three revenue requirements; is that correct?

A That's correct.

Q Why -- not from a technology basis, but from the basis of the revenue requirement -- is this one three times higher than the other two units, given that it appears to me that they are roughly the same vintage with very similar capacities?

A There are a couple of major differences. One is that Panda Stonewall is a .85 power factor generator, three generators. Panda Liberty and Panda Patriot are .9 factor generators. That materially changes one of the allocation factors.

In Panda Liberty and Panda Patriot, while the indirect project costs were identified, they were not included the rate. That has a substantial impact. Panda Liberty and Panda Patriot do not have the substantial natural gas transportation costs that Panda Stonewall has. The allocation factor to separate the generator and exciter from the rest of the turbines is about 3 percent higher at Stonewall as compared to Patriot and Liberty.

Q Do --

A The cost of financing in Liberty and