UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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Reactive Power Capability Compensation	)	Docket No. RM22-2-000
	)	

COMMENTS OF THE INDEPENDENT MARKET MONITOR FOR PJM

Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor ("Market Monitor") for PJM Interconnection, L.L.C. ("PJM"),[1] submits these comments responding to the Notice of Inquiry issued in the proceeding on November 18, 2021 ("NOI").[2]

The Market Monitor appreciates that the Commission is investigating these issues related to reactive power compensation in wholesale power markets. The NOI inquires about reactive power capability compensation under the *AEP* Method, alternative methods of compensation, and resources interconnected at the distribution level. The fundamental question is whether market design in the organized wholesale markets requires separate, guaranteed cost of service compensation for reactive capability. The answer is no. In the PJM market design, investment in resources is fully recoverable through markets. The PJM markets are a complete set of markets that are self sustaining. Unlike some ISO/RTO designs, the PJM market relies on markets rather than cost of service regulation or bilateral contracts to pay for capacity. Generators will invest in markets when the expected revenues provide for the payment of all costs and the return and of capital. That is the way competitive markets

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1 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").

2 *Reactive Power Capability Compensation*, Notice of Inquiry, 177 FERC ¶ 61,118 ("NOI").

work. It would be more equitable, more consistent with the PJM competitive market design, and more consistent with appropriate compensation for all generator costs, including reactive, to rely on PJM markets than to continue the outdated mixing of regulatory paradigms.

Even if the PJM design worked in the way asserted by supporters of cost of service payments for reactive, the best possible outcome would be the same as the market outcome. There would be an opportunity to recover all costs. A simple application of Occam's razor implies that the market approach should be used, as it is overwhelmingly more efficient than the current rate case, cost of service approach. Supporters of the cost of service approach have never explained why a nonmarket approach is required in PJM or why it is preferable to a market approach.

The current process is an inefficient waste of time because it relies on an atavistic regulatory paradigm that is not relevant in the PJM market framework. The *AEP* Method was created, before the creation of the PJM markets, by a regulated utility that had regulatory and financial reasons to want to define some generation costs as transmission costs. There is no reason to include complex rules that arbitrarily segregate a portion of a resource's capital costs as related to reactive power and that require recovery of that arbitrary portion through guaranteed revenue requirement payments based on burdensome cost of service rate proceedings.

Applying cost of service rules is costly and burdensome and unnecessary. Most reactive proceedings for generators in PJM are resolved in black box settlements that fail to address the merits of the cost support provided, result from an unsupported split the difference approach, and that, not surprisingly, produce a wide, unreasonable and discriminatory disparity among the rates per paid per MW-year.

Payments based on cost of service approaches result in distortionary impacts on PJM markets. Elimination of the reactive revenue requirement and the recognition that capital costs are not distinguishable by function would increase prices in the capacity market. The VRR curve would shift to the right, the maximum VRR price would increase and offer caps in the capacity market would increase. The simplest way to address this distortion would be to recognize that all capacity costs are recoverable in the PJM markets.

The NOI presents an opportunity to address the reactive issue using a market based approach that would resolve the double recovery issue.[3] The best approach would be to issue a rule eliminating cost of service rates for reactive capability and allowing for recovery of capacity costs through existing markets, including a removal of any offset for reactive revenue in offers and in the capacity market demand (VRR) curve. A second best approach would be to limit the revenue requirement that could be filed for under the OATT Schedule 2 to a level less than or equal to the reactive revenue credit included in the capacity market design, in the VRR curve net CONE value, currently $2,199 per MW-year.

As with all things in PJM markets, it is easy to focus on extreme complexity and lose sight of the big picture. The complexity includes power factors and power factor testing and convoluted and arbitrary allocation factors. The big picture here is that in PJM, the interrelated and self sustaining markets provide the opportunity for all power plants to recover all their costs, including a return on and of capital, including any identifiable reactive costs. There is no reason that part of those capacity costs should be paid directly in a non market, guaranteed, riskless revenue stream rather than in the market. The existence of the current option creates strong incentives for generators to maximize the allocation of capital costs to reactive in order to maximize guaranteed, nonmarket revenues.

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[3] *See* NOI at P 27.

I. COMMENTS

1. NOI: Questions regarding AEP Methodology-based Compensation

a. Does compensating resources based on their costs of investment in reactive power capability continue to be the appropriate basis for reactive power capability compensation? Why or why not?

No. The current process does not actually compensate resources based on their costs of investment in reactive power capability. The *AEP* Method assigns costs between real and reactive power based on a unit's power factor. This is effectively an allocation based on a subjective judgment rather than actual investment. There are few if any identifiable costs incurred by generators in order to provide reactive power. Separately compensating resources based on a judgment based allocation of total capital costs was never and is not now appropriate in the PJM markets. Generating units are fully integrated power plants that produce both the real and reactive power required for grid operation.

The *AEP* Method originated with a regulated utility assigning costs between two sources of regulated revenue requirement. The practice persists in PJM only because it provides a significant, guaranteed stream of riskless revenue. Generation owners have an incentive to maximize such guaranteed revenue streams.

There is no logical reason to have a separate fixed payment for any part of the capacity costs of generating units in PJM. If separate cost of service rates for reactive continue, they need to be correctly integrated in the PJM market design.

The best and straightforward solution is to remove cost of service rates for reactive supply capability and to remove the offset. Investment in generation can and should be compensated entirely through markets. Removing cost of service rules would avoid the significant waste of resources incurred to develop unneeded cost of service rates.

The result would be to pay generators market based rates for both real and reactive capacity.

i. **If so, does the AEP Methodology accurately reflect a resource's investment costs? Why or why not? To the extent your answer depends on the type of resource, please be specific.**

No. The *AEP* Method never accurately reflected the investment costs of providing reactive power, nor was it intended to do so. The *AEP* Method is a cost of service allocation approach designed to assign the regulated revenue requirement for generating units to a regulated generation function and a regulated transmission function. The *AEP* Method was designed to split that cost recovery for generating units in a reasonable way, based on a judgment about what is reasonable. The *AEP* Method was never about actually identifying specific capital costs associated solely with the provision of reactive power. Cost of service approaches apply allocation factors to accounting line items based on assumptions. The assumptions are that X percent of a type of equipment at a generating plant is associated with reactive power while (1-X) percent is associated with real power. The false precision of the *AEP* Method is entirely based on arbitrary assumptions. Even proponents of the *AEP* Method do not assert that the goal is to recover only the costs associated with a specific portion of a power plant required for the production of reactive power, or, in most cases, that such identification is even possible. That is not what the *AEP* Method was intended to do or is intended to do. The *AEP* Method does not define costs that are uniquely associated with the production of reactive power.

The *AEP* Method is based on the incorrect premise that the capacity costs of an integrated power plant are separable. The capacity costs of an integrated power plant are not separable.

The *AEP* Method is based on the incorrect premise that some capacity costs should be collected through markets while other capacity costs should be collected through nonmarket, guaranteed cost of service tariffs.

The fundamental flaw in the *AEP* Method approach is the assumption that the costs of providing reactive power are a function of the power factor. The power factor is the ratio of real power (expressed as megawatts or MW) to the total output (apparent power) of a generator (expressed as megavolt-amperes or MVA). The remaining output is reactive power (expressed as megavolt amperes reactive or MVAR). The allocator typically used by proponents of the *AEP* Method to assign costs to reactive power generation is (1 – (PowerFactor)^2). The power factor has superficial attraction as an appropriate allocator. The power factor is the core determinant of the reactive allocation factor in the *AEP* Method. Small changes in the power factor have large impacts on the costs allocated to reactive power. For a power factor of .95, the allocator is 9.75 percent while for a power factor of .90, the allocator is 19.00 percent, and for a power factor of .70, the allocator is 51.00 percent. For a resource claiming a power factor of .70, does that mean that more than half of the generator's costs were incurred in order to provide reactive power? Does this mean that 51 percent of the costs of the generator, exciter, and electrical equipment should be recovered through a cost of service rate? The answer to both questions is no. But resources have filed for guaranteed reactive revenue requirements on that basis.

The power factor has taken on somewhat mythical significance in the discussion of reactive power. There are frequently long discussions of power factors in reactive cases. The ratio of real to reactive power can vary significantly. The typical actual operating power factor of generators in PJM is determined by their voltage schedule and is usually between .97 and .99. The resultant *AEP* Method power factor allocator consistent with this actual reactive output of PJM generators and the actual tariff defined reactive output to generators is 5.91 to 1.99 percent. The nameplate power factor of thermal generating units is typically .85. But the nameplate power factor stamped on the generator at the factory and not based on actual operation on an actual grid. The nameplate power factor is meaningless for the actual operation of the power plant. The nameplate power factor does not mean that 27.75 percent of the power plant capital costs are associated with reactive power, although many resources have made that request because that is the power factor allocator based on the nameplate rating.

The power factor is not an appropriate allocator and does not reflect the actual capital costs associated with producing reactive power. The power factor has taken on a disproportionate significance in reactive rate cases because it is the single most important allocator in the *AEP* Method. That significance illustrates the fundamental flaws in the *AEP* Method.

The power factor does not measure reactive capability. The power factor does not determine a plant's reactive capability. The power factor does not identify costs associated with reactive capability or provide a reasonable basis for allocating those costs to reactive or real power production.

The power factor depends on how the generator is operated. An operator can produce more real power and less reactive power, or vice versa. The tradeoff is defined by the plant's D-curve. All generators are required to have the ability to produce some reactive power so they can operate safely within a grid under a voltage schedule. If, under unusual circumstances, PJM dispatchers request that unit provide more reactive power, a generator must reduce its real power output along its D-curve. In this situation, generators are directly paid for any lost energy revenues.[4]

PJM requires that all resources selling energy be capable of producing some of their MVA output as reactive power. Reactive capability requirements ensure that a resource can operate within the bounds of a voltage schedule and be available to operate outside the bounds of its voltage schedule when needed.[5] A voltage schedule is the voltage range within

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4 *See* OA Schedule 1 § 3.2.3B; *2020 State of the Market Report for PJM*, Vol 2. (March 11, 2021) at 238 (Table 4-1).

5 *See* OATT Attachment O § 4.7.1.2 ("Interconnection Customer agrees, as and when so directed by Transmission Provider or when so directed by the Interconnected Transmission Owner acting on behalf or at the direction of Transmission Provider, to operate the Customer Facility to produce reactive power within the design limitations of the Customer Facility pursuant to voltage schedules, reactive power schedules or power factor schedules established by Transmission Provider or, as appropriate, the Interconnected Transmission Owner. Transmission Provider shall maintain oversight over such schedules to ensure that all sources of reactive power in the PJM Region, as applicable, are treated in an equitable and not unduly discriminatory manner. Interconnection Customer agrees that Transmission Provider and the Interconnected Transmission Owner, acting on behalf or at the direction of Transmission Provider, may make changes to the schedules that they respectively establish as necessary to maintain the reliability of the Transmission System.").

which a generator must operate. Operating within these voltages ranges typically make the operational power factor between .97 and .99. The band is established by the transmission provider (PJM). Maintaining this voltage schedule requires that a small amount of a generator's output be in reactive power. To adjust output voltage, operators adjust the output of reactive power and therefore the operational power factor.

When dispatchers turn on a unit for energy, they need to know the approximate amount of reactive power (MVARs) can be obtained from the resource at each MW level. This helps them to know how many MVARs would be available if they are needed, or if they must reduce MW output to get additional MVARs, or if they would need to bring on additional generation. This information is available for dispatchers in eDART. Units operating at their maximum output can increase their reactive power only if they decrease real power. Reactive testing is required per MOD-25 to determine how much reactive power could be obtained throughout its operational range.

It is frequently asserted that the correct power factor can only be determined by a test. But power factor tests are frequently run in such a way as to test extreme power factor limits and typically require special operation by PJM and/or the local TO in order the ensure that the test does not reduce system voltage levels to dangerous levels. Although some generators want to use lower power factors in order to maximize the reactive payments, generators cannot routinely operate at lower power factors and generally cannot test at lower power factors because it would cause voltage drops on the PJM system. In reactive cases, generation owners have an incentive to claim the lowest possible reactive capability power factor in order to maximize the payment of guaranteed reactive revenue requirements. But during actual operations, generation owners have an incentive to maximize real power output because that is the energy they are paid for. If units are ever required by PJM to reduce real power in order to increase reactive output, the units are directly paid for those reductions. Such reductions occur only rarely on the PJM system.[6]

The central role of the power factor in the definition of reactive revenue requirements illustrates the issue with the *AEP* Method. It is never asserted that the power factor has anything to do with the actual costs of providing reactive power or any specific investment. The power factor is used as a way to assign costs based on only a very broad notion of causality. It is better characterized as reflecting a subjective judgment about fairness or reasonableness, couched in what appear to be factual discussions of power factors. The use of power factors to allocate capital costs between real and reactive power is classic example cost allocation as used in a regulated rate setting. But classic cost allocation was based on the requirement, in a regulated rate setting, to assign costs to different functions, and the goal was to divide the costs in a way that was supported by judgment. But there is no requirement in PJM markets to assign the costs to two different functions. PJM relies on markets and not on revenue requirement determinations. Capital costs are capital costs and all are recoverable through PJM markets. The use of the *AEP* Method as a rationale for creating a substantial nonmarket revenue stream should be terminated.

The original *AEP* Method was devised as a way to divide the cost of generation between two regulated sources of revenue. The outcome was less critical in a fully regulated environment. The regulated utility was guaranteed revenue recovery either way, subject to the limited revenue related risks of regulated utilities. The allocation method may have affected the allocation of generation costs among customer classes and may have changed recovery risk to the utility slightly.

In the PJM market, the *AEP* Method is about defining a guaranteed revenue stream that is exempt from market forces. This creates an incentive for generators to support high reactive allocation factors. The reverse would be true if generators received payment for real

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6 *See 2020 State of the Market Report for PJM*, Vol 2. (March 11, 2021) at 238 (Table 4-1).

power through guaranteed revenue requirement payments while reactive was compensated in a market. But no one has explained why reactive compensation should be exempt from market forces. The PJM model relies on competitive markets. Reactive power should not be an exception.

b. What is the appropriate time period for compensation from a rate developed under the AEP Methodology? Should payments be limited based on the useful lives of the plant at issue? Why or why not?

Under any method based on cost of service, the annual revenue requirement is based on an assumed asset life. The asset life used should reflect the expected useful life of the plant. Cost of service payments should be terminated at the end of that period. In addition, any capital recovery already achieved should be recognized in any cost of service rate for an existing power plant. A critical part of the calculation of the reactive revenue requirement under the *AEP* Method is based on the use of Capital Recovery Factors (CRF).[7] CRFs are a summary method for translating capital costs into revenue requirements. As a result, CRF values include a number of assumptions and must be calculated accurately. CRF values depend on capital structure, rates of return, tax rates, tax depreciation and asset life, among other things. CRF values are very sensitive to asset life. The CRF values used in reactive cases have not received enough attention and are generally overstated.[8] Black box settlements never identify the use of CRFs or the inputs into the CRFs.

c. As noted earlier, the power factor design criteria in the Commission's pro forma LGIA specify that the Large Generating Facility should be designed to maintain a composite power delivery at continuous rated power output, either at the Point of Interconnection for synchronous resources or at the high side of the generator substation for non-synchronous resources. Given this, when a resource conducts testing to demonstrate its reactive power

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7 The CRF is also sometimes referred to by different names, including the "annual fixed charge carrying rate" *See Ingenco Wholesale Power, LLC*, 173 FERC ¶ 61,247 (2020).

8 The Market Monitor explained CRF issues in comments related to the use of CRF values in calculating formula rates for black start service. *See* Comments of the Independent Market Monitor for PJM, Docket No. EL21-91-000 (November 11, 2021).

capability, over what minimum amount of time should a resource be required to maintain its maximum real power output while operating across its claimed reactive power factor range? Please specify to which type(s) of resource your proposed minimum time period corresponds.

The PJM requirement for most generators is that a generator be able to maintain a continuous rated power output at a power factor of at least .95 leading (absorbing) to .90 lagging (producing).[9] PJM requires that this power factor be provided across the full range of continuous rated power output, including its economic maximum.[10]

A large generator operating at a lagging power factor of 0.90 at its economic maximum MW output could result in very high/unsafe voltage levels on the PJM system. A generator's normal operation is within a PJM defined voltage schedule and therefore a power factor between 0.97 and 0.99. PJM operators are frequently not able to establish conditions under which a large generator or a generator in a constrained portion of the grid could safely run such a test. For smaller non-synchronous units weather conditions are often a factor. Solar units often file for reactive capability under perfect conditions, and these perfect conditions do not exist and could not reasonably be expected to exist in the unlikely case that their reactive capability was needed by transmission operators.

As a result, most reactive testing occurs at a MW output below the economic maximum output level and therefore does not meet the tariff standard that the power factor, used in the AEP Method allocator, be provided across the full range of continuous rated power output.

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9 *See* OATT Attachment O § 4.7.1.1.1 ("For all new Generating Facilities to be interconnected pursuant to the Tariff, other than windpowered and other non-synchronous generation facilities, the Generation Interconnection Customer shall design its Customer Facility 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….").

10 *See* PJM Manual 14D, para. E.3 Testing Requirements.

The complaints about PJM's inability to provide the testing that resource owners' want illustrates the problems with the *AEP* Method and its use of a primary allocator based on the power factor. The purpose of PJM's testing is to support reliable operations. PJM does not attempt to test for a 0.90 power factor while a power plant is operating at economic maximum because PJM has not determined that it needs the information.

i. **Reactive power capability, like real power capacity, is primarily a function of the unit's MVA rating. The Commission has found that, to the extent the resource has established that it is able to produce reactive power up to its nameplate capability, a resource may use up to its nameplate power factor in calculating its reactive power revenue requirements. Is there any reason for the Commission to believe that the nameplate capability aspect of calculating reactive power revenue requirements should be revised in order to produce a more accurate result? Why or why not? If so, in what manner (for example, should the power factor range identified in the interconnection agreement be considered)?**

Nameplate power factors are generally generic, mid-range, and represent an unloaded unit. The nameplate power factor is stamped on the generator at the factory and not based on actual operation on an actual grid. The nameplate power factor is meaningless for the actual operation of the power plant. The nameplate power factor does not mean that 27.75 percent of the power plant capital costs are associated with reactive power, although many resources have made that request because that is the power factor allocator based on the nameplate rating.

The power factor should not be used to determine reactive capability, whether it is based on nameplate ratings or tests.

d. **Many resources have an interconnection agreement in which reactive power requirements are addressed; however, to the extent that reactive power capability requirements are not addressed in a resource's interconnection agreement and a resource seeks compensation for supplying reactive power capability, how should the Commission address this? For example, should the Commission require that the resource and its transmission provider propose updates or additions to the interconnection agreement to specify the resource's reactive power capability requirements as a condition of**

establishing or maintaining a reactive power revenue requirement or should other methods be used in this regard?

In PJM, this is not an issue. Generating resources are compensated through markets. No separate compensation is required, regardless of the provisions of the interconnection agreement.

If the referenced reactive power is not required by the transmission provider, there should be no compensation.

If a Transmission Provider does not require a resource to have any capability or does not require capability above a certain level, then the Transmission Provider and its customers should not be required to pay for such reactive capability.

e. Reactive power filings set for hearing and settlement judge procedures often do not have active intervening parties other than the market monitor and RTO/ISO. Why do other parties not participate more in these proceedings?

It is not clear why customers are not better represented in reactive cases. But the administrative burden of keeping up with multiple cases with their attendant, and largely unnecessary, complexity is significant. There are over two dozen active proceedings concerning PJM reactive rates. Since 2016, there have been more than 100 such proceedings.

This lack of representation and the associated results of the cases could be addressed by recognizing that PJM markets provide for compensation for reactive power and that this significant administrative burden is a waste of time and money.

As an ongoing matter under the current approach, administrative efficiency would be improved if the Market Monitor, the RTO/ISO, affected customers and customer representatives were all required to be served with filings when made.

f. How does a resource's reactive power capability degrade over time? Does the degradation follow a predictable pattern over a certain period of time?

Does this answer vary depending on the generation type, real power capacity, and/or other aspects of a particular resource? If so, how?

Degradation of reactive power capability is not an issue. If the total output of the unit decreases over time, there is no reason to believe that the power factor would decline, as it is the ratio of real power to total power.

i. **Should resources receiving reactive power capability compensation undergo periodic reactive power capability testing to demonstrate that their reactive power capability compensation remains accurate?**

There is no relationship between the costs to produce reactive power and the tested power factor. Testing results are not meaningful as they depend on the activities of the grid operator and the transmission owner as much as the generator.

But, all generators should be routinely tested in the summer and winter to determine their reliable summer and winter ratings and their summer and winter operational reactive capability ratings. The reactive capability under normal operating conditions is essential.

a) **If so, how frequently should this testing be performed?**

All generators should be routinely tested in the summer and winter to determine their reliable summer and winter ratings and their summer and winter operational reactive capability ratings.

b) **Should the frequency of testing be influenced by other factors, including the generation type, real power capacity, and/or other aspects of a particular resource?**

All generators should be routinely tested in the summer and winter to determine their reliable summer and winter ratings and their summer and winter operational reactive capability ratings.

c) **Is there a period after a new resource begins operating during which testing is unnecessary? If so, what is the appropriate length of this period and why? Please clarify which type of resource(s) this period should apply to and why.**

No.

d) **Should reactive power capability compensation in all cases be linked to tested capability? If not, why not? If so, how? And, if so, should test results be updated and how frequently?**

Please see the response to section I.1.a.i.

g. **Should the AEP Methodology be modified to account for reactive power capability degradation over the lifetime of the resource and, if so, how?**

Degradation of reactive power capability is not an issue. If the total output of the unit decreases over time, there is no reason to believe that the power factor would decline, as it is the ratio of real power to total power.

i. **If the Commission makes such a modification, should the revised methodology only consider the resource's most recent reactive power capability testing results, or should the Commission incorporate degradation curves or other processes to estimate continued degradation between tests? If using degradation curves, should this methodology vary by resource type? If so, how? Should a resource have the opportunity to rebut the application of a degradation curve if it can demonstrate that its test results exceed the estimate derived from a degradation curve?**

Please see the response to section I.1.g.

ii. **Should the Commission adopt a standard minimum testing frequency for resources that receive reactive power capability compensation? If not, why not? If so, what time period should the minimum frequency be (e.g., testing required annually, biannually, every five years, etc.)? Please indicate to which type(s) of resources your proposed minimum frequency corresponds.**

Please see the response to section I.1.g.

h. **Over what time period does the NERC MOD-25-2 Reliability Standard accurately represent a resource's capability to provide reactive power?**

NERC MOD-25-2 applies to all units above a defined MVA capability connected to the grid regardless of how long they have been in operation. The applicable time period is for as long as the resource is selling energy in the PJM market. NERC is concerned with actual reactive power availability to the grid and not with compensation.

i. For how long is this data valid? Please explain.

Please see the response to I.1.h.

ii. If these standards do not accurately represent a resource's reactive power capability, what additional data should resources provide to verify their reactive power capability? Should this data vary by resource type? If so, how and why?

Please see the response to I.1.h.

i. Are there maintenance activities needed to maintain reactive power capability that do not also contribute to real power capability?

There are few, if any, identifiable costs, including maintenance costs, incurred by generators in order to provide reactive power.

i. If so, what percentage of a generating facility's operating and maintenance budget is necessary to maintain reactive power capability?

Please see the response to section I.1.i.

ii. Does this differ by type of generating resource? If so, how?

Please see the response to section I.1.i.

j. Is the existing AEP Methodology appropriate to allocate the costs associated with reactive power revenue requirements of non-synchronous resources? If not, why and can changes be made to the existing AEP Methodology to establish just and reasonable reactive power revenue requirements for non-synchronous resources? If so, please provide detailed descriptions of any potential changes and explain why they are necessary.

No. Even if the *AEP* Method were appropriate for thermal generation, it would not be appropriate for non-synchronous resources. Such generators have almost nothing in common with the technology that was the basis for the *AEP* Method. The *AEP* Method is not defined for such applications.

The applications of non-synchronous generators have included particularly egregious attempts to redefine capacity costs as related to reactive. In some cases, such generators have asserted that approximately half of the total capital costs of the resource are related to reactive and should therefore be paid under a guaranteed revenue requirement. The illogic of that result of the *AEP* Method illustrates why use of the allocation factor based on the power factor is not a reasonable basis for identifying the costs of providing reactive power. It is clearly implausible and clearly incorrect that half the capital costs of any resource are based on the costs of providing reactive. This further illustrates the incompatibility of the *AEP* Method and markets. Such attempts to apply the *AEP* Method should have been simply rejected, even under the current paradigm. Even under the current approach, such generators should have been required to demonstrate the actual costs, if any, incurred to provide reactive capability over and above that required as a condition of interconnection to the PJM system.

k. **As discussed above, the AEP Methodology determines a resource's cost of reactive power capability by applying an allocation factor to four groups of costs that are involved in the production or consumption of reactive power for a synchronous resource: (1) the generator and exciter, (2) the step-up transformer, (3) accessory electric equipment used to support the operation of the generator and exciter, and (4) the remaining production plant investment. For each of these groups of costs, assuming that the non-synchronous resource type can provide reactive power capability, please identify what non-synchronous resource equipment corresponds to the synchronous resource equipment used in the AEP Methodology and how that equipment is related to the production of reactive power. Please explain if that equipment is also related to the production of real power. Please specify if the equipment identified is specific to a type of non-synchronous resource (e.g., wind, solar, battery).**

Please see the response to section I.1.a.i.

i. **In the alternative, please describe what groups of costs are involved in the production or consumption of reactive power for a non-synchronous resource and how a non-synchronous resource's equipment would be allocated to each of those groups. Please explain if these groups are involved in the production or consumption of power other than reactive power**.

Please see the response to section I.1.a.i.

l. **Which, if any, of the four groups under the AEP Methodology do costs associated with the collection system of a non-synchronous resource fall into and why?**

Please see the response to section I.1.a.i.

i. **If they do not fall into any of those groups, should those costs related to the collection system be recovered? Why?**

Please see the response to section I.1.a.i.

ii. **Is the collection system comparable to the isolated phase bus of a synchronous resource? Why or why not? In what ways are they similar and in what ways are they different? What other aspects of a non-synchronous resource does a collection system serve?**

Please see the response to section I.1.a.i.

m. **Please explain whether it is necessary for a Type 3 wind turbine, Type 4 wind turbine, or solar PV facility to produce real power at a particular time in order for the resource to provide reactive power capability at that time.**

It is not necessary for such resources to produce real power in order to be able to extract power from the grid and return that power as reactive MVARs. PJM rarely, if ever, dispatches non-synchronous units for reactive power, including times when there is no sun or wind.

i. **If so, what are the implications, if any, for the current proportionality requirement on reactive power from non-synchronous resources?**

The PJM tariff defines the leading and lagging power factors for non-synchronous resources.

n. **Should the AEP Methodology be altered to account for the intermittent availability of some non-synchronous resources? Why or why not?**

Please see the response to section I.1.a.i.

o. **Solar resources can be designed with power factors much lower than those of synchronous resources, which implies a much higher reactive power capability and results in higher revenue requirements under current application of the AEP Methodology for solar generating facilities versus a comparable synchronous resource, all else being equal. Should the AEP Methodology be altered to account for this difference? Why or why not?**

If a standalone revenue requirement for reactive is retained, then it should be altered. The *AEP* Method is not applicable to non-synchronous resources. One way to address the issue is to provide the same reactive revenue requirement per MW-year to all qualifying resources, which is also the same revenue requirement used in the PJM capacity market design.

i. **Refer to Section II.A.5, question l.i. Would allocating the costs of solar generating facilities into cost categories different from those categories defined under the AEP Methodology, and using a solar generating facility's power factor, result in a revenue requirement more or less comparable to that of a synchronous generating facility, all else being equal?**

No. Attempts to force solar generation into the *AEP* Method are inappropriate. While a market approach is preferable, under the current revenue requirement approach, only the identifiable actual costs associated with specific equipment (not allocated costs) should be included.

p. **What options are available to collect independently verifiable cost information from MBR sellers that have received waiver of the accounting and FERC Form No. 1 requirements to support their reactive power capability revenue requirements? For example, how should MBR sellers that receive reactive power capability compensation track their equipment costs and support their proposed reactive power revenue requirements?**

The NOI explains (at P 25) that one of the reasons there are so many reactive capability rate proceedings is that sellers with market based rates authorization received a waiver from the accounting and reporting practices required to support cost of service rates. Excusing sellers from such practices anticipated sellers' participation in markets. If sellers wish to continue to participate in cost of service proceedings, then sellers must continue to adhere to the necessary accounting and reporting practices.[11]

No waiver should apply or should have applied to MBR sellers seeking to establish a cost of service rate for a reactive capability resource. The requirements to support a cost of

[11] Another reason to avoid cost of service proceedings is confidentiality. It is important to the markets and important to competitors to keep their cost information confidential. Cost of service review means disclosing competitive and market sensitive information necessary to support cost of service rates. Confidentiality agreements are not reliable, and in some case competitors have intervened and executed confidentiality agreements.

service revenue requirement should not be relaxed because it concerns reactive power capability. The same standards that apply to cost of service ratemaking for an entire resource should apply to a substantial portion of a resource. The basis for the waiver is the assumption that the seller would be participating in markets and that the obsolete cost of service approach would be discarded. The best approach would be to validate the assumption, rely on markets, and discard the cost of service approach.

q. In order to simplify and provide transparency to proposed reactive power capability compensation filings, should the Commission require, in PJM, MISO, and non-RTO/ISO regions that compensate for reactive power capability based on the costs of individual resources or on a fleet-wide basis, reactive power filers to include with their filing a standardized form with recognized schedules and officer and independent accountant certification requirements? Please explain why or why not.

The standards to support reactive capability rates under the cost of service approach should not be streamlined or relaxed. Customers pay significant amounts for reactive capability, and they deserve full protection under the Federal Power Act. The correct way to avoid the burdens and waste associated with current flawed market design would be to discontinue cost of service ratemaking proceedings and rely on competitive markets. In the alternative, use of a single revenue requirement per MW-year for all reactive resources would eliminate the waste associated with these proceedings.

i. Would the standardized form allow for better comparisons between reactive power rates and/or allow the reactive power rates to be more easily refreshed to reflect degradation or other changes to reactive power capability? If not, why not?

Please see the response to section I.1.q.

ii. Should the form contain similar information as the relevant USofA accounts used in the AEP Methodology? If not, why not? If yes, please specify the types of information that would be necessary to calculate a reactive power revenue requirement.

Please see the response to section I.1.q.

iii. **If the Commission pursued a standardized form approach, what cost support should be included in a standardized form?**

Please see the response to section I.1.q.

r. **Refer to the PJM Market Monitor's concerns regarding the potential in PJM of overpayment for reactive power capability. In PJM and other RTOs/ISOs with centralized capacity markets, how do resources typically account for revenues from reactive power compensation when calculating their capacity offers?**

The PJM market design allows for the competitive investment in generation resources. The addition of separate rules allowing for the recovery of an arbitrarily defined portion of the same investment on a cost of service basis introduces a flaw into the competitive market design. The flaw is exacerbated when separate cost of service proceedings define the revenue requirement cost to supply reactive at values ranging from $13,044 to $964 per MW-year.

The real issue is that the revenue requirement approach is inconsistent with both the theory and mechanics of PJM markets. The impact is to distort market outcomes.

The rules that account for recovery of reactive revenues are built into the auction parameters, specifically, the VRR Curve. The PJM market rules explicitly account for recovery of reactive revenues of $2,199 per MW-year through inclusion in the Net CONE parameter of the capacity market demand (VRR) curve.[12] The Net CONE parameter directly affects clearing prices by affecting both the maximum capacity price and the location of the downward sloping part of the VRR curve. In addition, market sellers, when submitting offers based on net avoidable costs must account for revenues received through cost of service reactive capability rates in the calculation.[13] Unit specific reactive capability rates up to that level are at least consistent with that parameter. Reactive capability rates either above or below that level distort capacity market outcomes. For example, a marginal resource with

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12 *See* OATT Attachment DD § 5.10(a)(v)(A).

13 OATT Attachment DD § 6.8(d).

reactive revenue of $5,000 per MW-year reflected in their net ACR offer would suppress the capacity market clearing price. Conversely, a marginal resource with a reactive revenue of $1,000 per MW-year reflected in their net ACR offer would inflate the capacity market clearing price.

i. **If a resource accounts for revenues from reactive power compensation when calculating its capacity offers, does that approach ensure that the resource does not receive double compensation for providing reactive power capability service? Please explain why or why not.**

No. Please see the response to section I.1.r.

ii. **Please explain how the lack of accounting for revenues from reactive power compensation when calculating resources' capacity offers does not constitute double compensation.**

Please see the response to section I.1.r.

s. **Do resources in PJM that receive reactive power capability compensation above $2,199/MW-year effectively receive double-recovery as alleged by the PJM Market Monitor?**

Yes. Please see the response to section I.1.r.

i. **If so, how should such overcompensation be corrected?**

The best approach is to eliminate OATT Schedule 2 and the provision for reactive revenue requirement recovery from the PJM market rules. The provisions in OATT Attachment DD that address Schedule 2 reactive revenues should also be removed. Going forward, all investment in power production plant should be recovered through competitive markets.

In the interim, no rate under Schedule 2 exceeding $2,199 per MW-year should be approved.

ii. **If not, please explain why no double-recovery occurs.**

Please see the response to section I.1.r.

2. **NOI: Questions re Alternative Methodologies**

   a. **Should alternative methodologies to the AEP Methodology be considered for the calculation of reactive power capability revenue requirements? If not, why not? If so, what alternative methodologies to the AEP Methodology could be used for calculating reactive power revenue requirements that would accurately capture the cost of providing reactive power capability? Please clarify if any methodology is specific to certain types of resources or not. For example, what methodology could appropriately account for the technical characteristics of non-synchronous resources that do not exist in synchronous resources? How would developing revenue requirements under such a new methodology compare to developing revenue requirements using the AEP Methodology?**

There is no reason to compensate reactive capability outside of the market, whether using the *AEP* Method or an alternative to the *AEP* Method.

   b. **Should a flat rate approach to reactive power compensation differ depending on the type of resource, or should one rate be used for all resource types?**

There is no reason not to rely on competitive markets. A flat rate would operate as a subsidy, interfere with competitive pricing and continue to require rules to insulate the capacity market design from its impact.

Under the existing market rules in PJM, reactive capability rates exceeding $2,199 should not be approved to avoid double recovery. Correct application of the existing PJM market rules would effectively create a flat rate at $2,199 per MW-year.

   c. **Under a flat rate approach:**

      i. **How should the rate be initially set, and how would it be adjusted over time (e.g., for inflation)?**

Please see the response to section I.2.b.

      ii. **Should payments to a specific resource be based on the resource's tested reactive power capability or its actual reactive power output?**

Please see the response to section I.2.b.

iii. **How often should the resource's reactive power capability be tested?**

Please see the response to section I.2.b.

d. Under a replacement cost approach:

i. **What alternative technology should be used to establish the rate and how should that alternative technology be determined?**

There is no reason not to rely on competitive markets.

ii. **How often should the alternative technology used to establish the rate be reevaluated?**

Please see the response to section I.2.d.i.

e. Would a change to a flat rate or replacement rate approach require resources to change any of their accounting, record keeping or any other administrative processes?

Please see the response to section I.2.d.i.

i. **Would such a change have an impact on capital investment decisions? Are there any other effects that such a change would cause? If possible, please provide numbers to quantify statements.**

Please see the response to section I.2.d.i.

f. In regions such as CAISO and SPP, where resources are not directly compensated for their reactive power capabilities, how do resources recover the costs of their investment in reactive power capability?

Resources do not need separate compensation for reactive capability. There is no reason to arbitrarily divide resource capital costs into two categories, unless the purpose is to assign the responsibility for payment to different groups.

g. Refer to the PJM Market Monitor's proposal to provide for reactive power compensation in PJM through the capacity market rather than through a separate cost-of-service construct. In regions with a centrally-cleared capacity market, would it be preferable for resources to recover the costs of their investment in reactive power capability by embedding those costs in their capacity market offers, rather than using a separate cost-based rate? Please describe any advantages or disadvantages to this approach and any

modifications this would require in the applicable region's OATT and market rules.

This question implies that action to embed reactive capital costs would be required. Under the current market design, generators already include costs associated with their entire plants in the capacity market. All capital costs are included in the Net CONE parameter of the VRR curve in the capacity market. The only change that would be required would be to exclude the $2,199 per MW-year revenues from the Net CONE parameter and to exclude any reactive revenues from the energy and ancillary services offset from the offer caps for resources that provide reactive. An advantage of competitive markets is that resources have an incentive to meet their minimum reactive capability requirements at lowest cost.

3. NOI: Questions re Distribution-Connected Resources

a. For a distribution-connected resource, is reactive power dispatchable by direction of the transmission provider? Please explain, including whether the answer to this question depends on whether the resource has a Commission-jurisdictional interconnection agreement with the transmission system owner/operator and whether the resource is synchronous or non-synchronous.

PJM has dispatch authority over resources selling power into PJM regardless of whether they are interconnected to the transmission system, the distribution system or are external to PJM and participate in pseudo tie arrangements. *See* OA Schedule 1 § 1.7.20(b). The status of the resource as a market seller under the PJM Market Rules determines whether the resource is dispatchable. PJM's dispatch authority does not depend on whether there exists a jurisdictional interconnection agreement. Resources responding to PJM dispatch receive compensation under the PJM Market Rules based on opportunity costs. *See* OA Schedule 1 § 3.2.3B. A resource is compensated under the PJM Market Rules regardless of whether it is also compensated for reactive capability supply under Schedule 2 to the OATT. The compensation provisions for responding to PJM dispatch and providing reactive supply capability are separate under the current PJM Market Rules.

The eligibility of a generating unit to collect rates for reactive supply capability under Schedule 2 to the PJM OATT (Schedule 2) requires that the generating facility provide the reactive supply capability that is necessary for PJM to provide, in PJM's role as Transmission Provider, Reactive Supply and Voltage Control service on the PJM Transmission System. This eligibility implies that the generating facility must be interconnected directly to the PJM system.

b. If reactive power produced by a distribution-connected resource cannot be dispatched by the transmission system operator to provide voltage support to the transmission system, should a distribution-connected resource be compensated through transmission rates for its reactive power capability? Why or why not?

No. If PJM cannot make use of whatever reactive capability a resource has in order to maintain voltages on the PJM system, PJM cannot rely on the resource to provide reactive supply and voltage control. Among other things, OATT Schedule 2 requires that eligible resources be under PJM's control. Schedule 2 explicitly excludes behind the meter generation from eligibility.

c. If distribution-connected resources are dispatchable for reactive power by the transmission provider, to what extent are distribution-connected resources able to provide reactive power capability service to the transmission system? Are there physical characteristics (e.g., distribution-connected resource characteristics and location, system topology, etc.) or other indicators that could be analyzed to determine accurately whether a distribution connected resource is able to provide reactive power capability service to the transmission system?

Under the current PJM market design, the more fundamental question is whether the PJM has assumed the responsibility to monitor and operate the system at the location where the resources is connected. PJM procures reactive supply capability in order to ensure that it will have the resources available at all locations where it provides transmission service so that it can provide reactive supply and voltage control service. If PJM is monitoring and operating facilities that would be classified as distribution, and can, therefore, provide reactive supply and voltage control service at that location, and resources interconnecting at that location are under PJM's "control" and can be used to "maintain transmission voltages on the [PJM's] transmission facilities within acceptable limits" as Schedule 2 requires, then those resources would be eligible to file for rates under Schedule 2.

d. Are resources connected to a distribution system subject to reactive power capability testing requirements? If so, what are those requirements?

The entity responsible for the system where the resource is interconnected (i.e., the local distribution company) may include requirements related to reactive capability in its interconnection service agreement. The Market Monitor is aware of some circumstances where the interconnection service agreement excused the interconnecting resource of any such requirements.[14] PJM typically uses a standard interconnection service agreement that includes as parties the resource owner, PJM and the transmission or distribution system owner.[15] Thus, the same reactive power capability testing requirements typically apply regardless of whether the resource is providing reactive power capability to PJM in its role as the transmission provider or to the operator of the distribution system.

II. 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,

Jeffrey Mayes

Joseph E. Bowring

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14 *See Ingenco Wholesale Power, LLC*, 173 FERC ¶ 61,247 at P 24 (2020) ("Dominion argues that for those Generating Facilities with GIOAs (i.e., the Amelia, Charles City, Chesterfield, Dinwiddie 1, Dinwiddie 2, Rockville 1, Rockville 2 and VA Beach facilities), there is no requirement in the GIOAs to provide leading and lagging reactive power. Thus, Dominion argues that Ingenco should not receive compensation under Schedule 2 for these facilities since they are not obligated to provide reactive power as directed by PJM.").

15 *See* PJM OATT Attachment O.

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