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BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company	)))	Case No. 10-2929-EL-UNC

COMMENTS OF FIRSTENERGY SOLUTIONS CORP.

FirstEnergy Solutions Corp. ("FirstEnergy") hereby submits these written comments on the capacity charges currently recovered and proposed to be charged by Ohio Power Company and Columbus Southern Power Company (collectively, "AEP-Ohio"). AEP-Ohio already recovers capacity charges in PUCO-approved rates, but nevertheless filed an application for additional compensation at the Federal Energy Regulatory Commission ("FERC"). That filing triggered the PUCO's December 8, 2010 Entry and this review of AEP-Ohio's capacity charges.

FirstEnergy responds to the Commission's Entry as follows: (1) AEP-Ohio has not shown that any changes are necessary to its existing Provider of Last Resort ("POLR") Rider—the state mechanism for AEP-Ohio to recover capacity costs associated with retail switching, (2) AEP-Ohio has failed to show the degree to which it is already recovering its capacity costs and whether the new wholesale charge would result in double-recovery, and (3) AEP-Ohio's proposed wholesale charge would devastate retail choice in Ohio.

INTRODUCTION

On November 24, 2010, AEP-Ohio filed for new "capacity compensation formulae" at FERC. In support, AEP-Ohio erroneously asserted that "Ohio has not established a compensation mechanism for capacity sales." *PJM Interconnection, L.L.C.*, Docket No. ER11-2183-000, Tariff Filing at 3 (Nov. 24, 2010) ("November 24 Filing"). AEP-Ohio stated that it had been receiving compensation to date based on rest-of-pool clearing prices but now proposed to switch to cost-based recovery. *Id.* The new rates would be charged only to Competitive Retail Electric Service Providers ("CRES Providers"). FirstEnergy is a CRES Provider.

Using 2009 numbers, AEP's new proposed wholesale rate would be \$388/MW-day. *See* November 24 Filing, Attachment A, Part 1, at 1. In contrast, rest-of-pool clearing prices—the default rate—for the 2009/2010 delivery year were \$102/MW-day, but the most recent auctions have cleared at \$16.46/MW-day (for 2012/2013) and \$27.73/MW-day (for 2013/2014). These market clearing prices are the rates that CRES Providers have relied upon in contracting with their own retail customers in Ohio for these periods of time.

Also by way of contrast, the 2013/2014 PJM rest-of-pool value for the gross cost of new entry (unadjusted by other market revenues) was \$335/MW-day. In other words, AEP-Ohio's proposed wholesale rate would be over 15 percent higher than PJM's currently calculated cost of new entry and higher than RPM clearing prices from any zone—including constrained zones—to date.

AEP-Ohio would be unequivocally precluded from filing for this new wholesale rate under the PJM tariff if it had not opted out of PJM's capacity market. Normally, wholesale capacity rates in PJM are set via the Reliability Pricing Model ("RPM")—PJM's capacity market. RPM uses a "base residual auction" run three years in advance to set capacity prices. After seller offers are stacked from least- to most-expensive, the auction clears at the offer price of the final resource needed to procure the required amount of capacity.

The PJM tariff provides an opt-out mechanism—the Fixed Resource Requirement ("FRR")—for zones that do not want to participate in RPM. AEP has voluntarily chosen to opt out. FRR entities like AEP commit to self-supply a fixed amount of capacity in the amount needed for all load and projected load growth in a zone. They must opt out before the base residual auction (*i.e.*, over three years before the delivery year) and commit to at least five years as an FRR entity. This is done to disallow toggling back and forth between auction outcomes and their own arrangements, which would permit FRR entities to always take the higher of market or cost-based outcomes and thus over-recover their costs. By opting out, FRR entities like AEP avoid paying auction rates for capacity. Even so, AEP continues to collect wholesale capacity revenues under its FRR plan.

The FRR rules include provisions to address compensation in a retail choice state, like Ohio. In Ohio, retail choice customers can choose to buy energy from CRES Providers but would still get their capacity from the provider of last resort, in this case AEP-Ohio. A CRES Provider, like FirstEnergy, thus sells retail customers energy at a negotiated rate that *includes* AEP's capacity charge. Retail providers also have the option to self-supply their own capacity—to become their own FRR Entity—if they do not want to pay AEP's rates. The PJM tariff requires that they too must enter into their self-supply arrangements at least three years in advance of the base residual auction. This permits the CRES Provider's self-supplied capacity to be incorporated into the FRR entity's plan.

AEP continues to provide the same "fixed" amount of capacity regardless whether retail choice customers switch from AEP to a CRES Provider. Recognizing this, the PJM tariff clarifies how to compensate the FRR entity in a retail choice state. The state is given priority, as follows:

> In the case of load reflected in the FRR Capacity Plan that switches to an alternative retail LSE, where the state regulatory jurisdiction requires switching customers or the LSE to compensate the FRR Entity for its FRR capacity obligations, *such state compensation mechanism will prevail.* In the absence of a state compensation mechanism, the applicable alternative retail LSE shall compensate the FRR Entity at [rest-of-pool or "RTO" RPM clearing prices], provided that the FRR Entity may, at any time, make a filing with FERC under Sections 205 of the Federal Power Act proposing to change the basis for compensation to a method based on the FRR Entity's cost or such other basis shown to be just and reasonable....

PJM Reliability Assurance Agreement ("RAA"), Schedule 8.1, Section D.8 (emphasis added). AEP has opted-out of RPM, including AEP-Ohio in a retail choice state (Ohio). AEP-Ohio thus has the conditional option of seeking cost-based recovery of capacity costs but *only if there is no state capacity compensation mechanism.*

Ohio indeed does have a capacity compensation mechanism in place, and thus, in accordance with the PJM RAA, AEP-Ohio has no option to circumvent the state mechanism and seek wholesale recovery at FERC. AEP-Ohio's PUCO-approved retail rates include the POLR Rider, which–according to AEP's own witness in his original sponsoring testimony—recovers capacity and energy costs associated with the contingency that a retail choice customer may return to AEP-Ohio on short notice. AEP-Ohio also charges an Environmental Investment Carrying Cost Rider, which recovers costs associated with keeping AEP-Ohio's generation fleet in operation. In addition, there likely are other retail rate mechanisms that permit AEP-Ohio to recover capacity costs.

Notwithstanding these state compensation mechanisms, AEP-Ohio has to date been recovering both its state capacity compensation (the POLR Rider and other retail mechanisms) *and* wholesale compensation based on RTO clearing prices. This is double-recovery, and it has been in error. With state mechanisms in place, AEP-Ohio is not entitled to *any* additional wholesale compensation. We have asked FERC to order refunds of these improperly collected amounts. We have also asked FERC to reject AEP-Ohio's attempt for additional cost-based recovery in wholesale rates.

In response to AEP-Ohio's FERC filing, the PUCO initiated this review of AEP-Ohio's capacity charges. *See In re Comm'n Review of Capacity Charges of Ohio Power Company & Columbus S. Power Co.*, PUCO Case No. 10-2929-EL-UNC, Entry (Dec. 8, 2010) ("PUCO

Entry") at ¶ 5. The PUCO itemized three issues for review (*see id.*), but in each case the initial burden of proof must be on AEP-Ohio. Since AEP-Ohio chose not to disclose fundamental cost-recovery information in its FERC filing, there is very little evidence on these issues, and thus we are at a significant disadvantage in commenting on AEP-Ohio's proposal. AEP-Ohio should be required to disclose all relevant data to the PUCO Staff and other parties. To the extent necessary, all parties should be given the opportunity to conduct full discovery of all relevant AEP costs and revenues.

Even without critical information from AEP-Ohio, we can respond to the three issues the PUCO raised as follows:

First, AEP-Ohio has not shown that any changes are necessary to its existing POLR Rider or other retail mechanisms currently in place for recovering capacity costs. The only required change is for AEP-Ohio to discontinue collecting wholesale capacity charges of any kind—including those based on RPM auction clearing prices—because there already is a state mechanism in place. If AEP-Ohio is dissatisfied with the capacity revenues that it collects in its POLR Rider and other retail mechanisms, its recourse is to seek to change those retail rates at the PUCO. AEP-Ohio has not made any such filing.

Second, in its FERC filing, AEP-Ohio failed to show the degree to which it was already recovering its capacity costs and whether the new wholesale charge would result in double-recovery. This is essential information that should be the fundamental basis for any change in the retail rate, and should accordingly be argued before the PUCO. Other omissions and flaws in AEP-Ohio's FERC filing include:

- AEP-Ohio provided no evidence in support of the calculation of its capacity costs;
- AEP-Ohio apparently sought the fully embedded costs of its generating capacity and did not explain why this method should be allowed when it is excessive and

inconsistent with the capacity costs that generators are allowed to bid for under the RPM program;

- Even if the POLR Rider and other retail collections did not preclude the filing, AEP-Ohio failed to offset the POLR Rider and other retail charges related to capacity in the proposed wholesale rates, resulting in double-recovery of capacity costs;

- AEP-Ohio never mentioned the interstate pooling agreements that it has between its affiliates and how capacity charges under these agreements and any off-system sales would affect the rates at issue here;

- AEP-Ohio made no showing that it was only charging the portion of the capacity costs of the specific resources required to meet its Fixed Resource Requirement (which is the only cost element that is authorized for recovery under PJM's tariffs);

- AEP-Ohio made no showing that it was only charging CRES Providers for the FRR capacity required *in Ohio*;

- AEP-Ohio made no showing that the capacity rates at issue would also be applied to AEP-Ohio's POLR customers and to its own merchant affiliate (*i.e.*, that CRES Providers would only pay their *pro rata* share of AEP-Ohio's capacity costs);

- AEP-Ohio did not demonstrate how it was treating other PJM market revenues and opportunity costs;

- AEP-Ohio failed to explain its attempt to apply discriminatory pricing for its retail choice customers in Ohio while all other AEP customers that are located in PJM but outside of Ohio would pay lower costs; and

- AEP-Ohio failed to justify its formula inputs, only highlighting a handful of the inputs and citing largely irrelevant precedent from non-controversial FERC cases with much less at stake.

AEP-Ohio failed to address these fundamental issues and left scores of related rate questions unaddressed and unanswered. Without answers to these questions, the PUCO's review will be impossible. But in short, it appears almost certain that AEP-Ohio is already collecting through other rates and agreements many of the same capacity charges that it sought to collect at FERC.

Third, AEP-Ohio's proposed wholesale charge will devastate retail choice in Ohio. In its FERC filing, AEP-Ohio omitted any discussion of this issue. But assuming CRES Providers have the contractual ability to pass on the rate, AEP's proposal begs the question why any retail customers in Ohio would switch service providers away from AEP-Ohio to begin paying a capacity rate many times higher than current market rates.

Aside from the exorbitance of AEP-Ohio's proposed rate, its timing also hurts retail choice. AEP-Ohio sought an effective date of January 1, 2011. January 1 was just over mid-way through the 2010/2011 power delivery year (which runs from June 1, 2010 to May 31, 2011). In mid-delivery year, CRES Providers are fully locked-in to AEP's program and have no way under the PJM tariff to self-supply out of the rate, or to change their existing contractual arrangements with their own customers.

In fact, CRES Providers have already made contractual commitments for the periods covered by each base residual auction held to date (currently through the 2013/2014 delivery year). In so doing, they have relied upon the PJM rules and rates in place at the time of the forward capacity auctions—three years forward. CRES Providers may or may not have the ability under existing agreements to pass on AEP's new rate to their retail customers. In either case, the AEP-Ohio capacity component of the rate will increase dramatically after-the-fact, and upset fundamental market expectations. This will of course have a chilling effect on future retail choice.

In sum, AEP-Ohio has provided no justification to change the capacity compensation that it is collecting in retail rates. And with the POLR Rider and other state compensation mechanisms in place to cover capacity costs associated with retail switching, AEP-Ohio has no right to any wholesale compensation.

In support of these comments, we attach an affidavit from Dr. Roy Shanker, an economist specializing in RTO design issues, which we included with our FERC protest (Attachment A hereto, "Shanker Affidavit"). Dr. Shanker discussed the numerous flaws with AEP-Ohio's FERC filing and the same arguments are relevant here.

ARGUMENT

I. AEP-OHIO HAS NOT SHOWN THAT ANY CHANGES ARE NECESSARY TO ITS CURRENT STATE CAPACITY COMPENSATION MECHANISMS

AEP-Ohio currently collects capacity costs in retail rates and has made no showing that any changes are necessary to these rates. AEP-Ohio in fact has not filed to change its retail rates.

A. The POLR Rider Recovers Capacity Costs

The PUCO has already approved a mechanism for AEP-Ohio to recover capacity costs associated with retail switching. The "POLR Rider" in AEP-Ohio's rates covers the capacity and energy costs associated with the contingency that departed retail customers will return to AEP-Ohio. *See In re Application of Columbus S. Power Co.*, PUCO Case Nos. 08-917-EL-SSO & 08-918-EL-SSO, Opinion and Order at 38–40 (Mar. 18, 2009) (discussing POLR Rider), Attachment B hereto ("PUCO Rate Order"); *In re Application of Columbus S. Power Co.*, PUCO Case Nos. 08-918-EL-SSO & 08-918-EL-SSO, Direct Testimony of J. Craig Baker on Behalf of Columbus Southern Power Company and Ohio Power Company at 25:14–34:23 (July 31, 2008), Attachment D hereto ("Baker Testimony"). According to the PUCO:

> [T]he proposed POLR charge is based on a quantitative analysis of the cost to [AEP] to provide to customers the optionality associated with POLR service [citing Baker Testimony at 25–26]. AEP-Ohio argued that this charge covers the cost of allowing a customer to remain with [AEP], or to switch to a [CRES] provider and then return to [AEP's] SSO after shopping [citing *id.*].

PUCO Rate Order at 38.

This rate is charged to load in AEP-Ohio's service territory, whether the customer has switched to a CRES Provider or not. A customer can avoid paying the charge only if it agrees that if it returns to AEP-Ohio, it will pay market rates.

In supporting this retail charge, AEP-Ohio argued that "[a]ll customers, even those who have switched generation suppliers, have the right to rely on [AEP-Ohio as the incumbent provider] for generation service." Baker Testimony at 34:14-15. As AEP-Ohio's witness explained:

> This flexibility leaves [AEP] in the precarious position of being exposed to losing generation service load when the market price is low but needing to stand ready to begin serving that load again when the market price is high, and in the case of a CRES or other supplier default, doing so at a moment's notice. There is a definite and significant cost associated with providing this flexibility. In addition to the challenges of providing *capacity and energy* on short notice, [AEP] would provide service to returning customers at the [Standard Service Offer] rate (even though they are likely to be returning because market prices exceed the [Standard Service Offer]).

Id. at 26:7-15 (emphasis added). The revenue requirement is thus based on the cost of all of the capacity needed to provide service in Ohio. And, in fact, the POLR rider is *specifically designed* to recover capacity costs associated with retail choice.

B. AEP-Ohio Has Failed To Show That the Capacity Costs Recovered in the POLR Rider Are Somehow Different than Capacity Costs in General

After failing to even mention it in its initial filings, AEP-Ohio filed a response to various protests at FERC to attempt to distinguish the capacity costs that it collects in the POLR Rider from the costs of AEP's installed capacity. AEP-Ohio stated that "[s]imply put, the PUCO's approval of retail POLR charges do not [sic] compensate [the AEP-Ohio companies] for the wholesale capacity that they are required to make available as FRR Entities under the RAA." Response of American Electric Power Service Corporation, Docket No. ER11-2183-000 (Dec. 17, 2010) ("AEP-Ohio Response"), at 9. Furthermore, according to AEP-Ohio, "[t]he POLR charges relate to an entirely different service and are based on an entirely different set of costs than the capacity rates provided for under" the PJM tariff. *Id.*

To the contrary, there does not appear to be any difference whatsoever. The POLR Rider is designed to recover the costs "of providing *capacity* and energy on short notice." *Id.* at 14, quoting Baker Testimony at 26. This is how AEP-Ohio originally supported the charge at the PUCO. Now, however, while still quoting the same language, AEP-Ohio argues that "[t]he cost of [AEP-Ohio's] POLR obligations result [sic] from trying to balance and quantify two of the goals of electric restructuring in Ohio, *not from the cost of AEP's installed capacity*." *Id.* at 14 (emphasis added). The "two goals," according to AEP-Ohio, are flexibility for retail customers to switch providers and rate stability through a default standard service offer. *Id.*

But "flexibility" exists because of AEP's fleet of generating capacity. And AEP's standard service offer is also derived from the costs of AEP's fleet of generating capacity. There are no special generating units set aside solely to provide POLR service in the event that retail choice customers switch back to AEP-Ohio. The POLR Rider and the proposed wholesale capacity charge both ultimately pay for the same generating capacity. The simple question, which AEP-Ohio has not addressed, is how much does AEP-Ohio's generation capacity actually cost and what revenues does AEP-Ohio already recover. AEP-Ohio is not entitled to additional compensation to "balance and quantify" the alleged costs of abstract "goals."

C. *The POLR Rider Is the State Capacity Compensation Mechanism*

Strangely, AEP-Ohio never mentioned the POLR Rider in its FERC application for a new wholesale capacity rate. That was an indefensible omission. Under the PJM tariff, AEP-Ohio and other FRR entities have no option for wholesale recovery of capacity costs associated with retail switching if a state compensation mechanism is in place:

> In the case of load reflected in the FRR Capacity Plan that switches to an alternative retail LSE, where the state regulatory jurisdiction requires switching customers or the LSE to compensate the FRR Entity for its FRR capacity obligations, such state compensation mechanism will prevail. In the absence of a state compensation mechanism, the applicable alternative retail LSE shall

> compensate the FRR Entity at [rest-of-pool or "RTO" RPM clearing prices], provided that the FRR Entity may, at any time, make a filing with FERC under Sections 205 of the Federal Power Act proposing to change the basis for compensation to a method based on the FRR Entity's cost or such other basis shown to be just and reasonable....

RAA, Schedule 8.1, Section D.8. Thus, if a state has established a retail compensation mechanism for capacity, that compensation mechanism controls *and no wholesale capacity compensation is available*. This provision is designed in part to prevent exactly what AEP-Ohio has proposed—double-recovery of capacity costs through separate approvals by two different regulatory jurisdictions.

AEP-Ohio asserted at FERC that "Ohio has not established a compensation mechanism for capacity sales." November 24 Filing at 3. This subtly misstated the PJM tariff test, which actually is whether the state has a mechanism "to compensate the FRR Entity for its FRR capacity obligations." RAA, Schedule 8.1, Section D.8. The "POLR rider" is a straightforward instrument to compensate AEP for these obligations. It would only be under a tortured reading that the POLR rider would *not* be considered a capacity compensation mechanism as envisioned by this provision of the PJM tariff.

With this mechanism in place, AEP-Ohio has no option under the PJM tariff (the Reliability Assurance Agreement) to file at FERC for wholesale compensation. The RAA does not specify whether charges already being collected in retail rates must be fully compensatory or not; it only asserts that if such retail charges exist, no wholesale recovery is available.

D. With the POLR Rider in Place, AEP-Ohio Is Not Entitled to Auction Revenues for Capacity

In our view, the POLR Rider *is* the state capacity compensation mechanism. The PUCO certainly agrees that a state compensation mechanism is already in place and that cost-based wholesale recovery is foreclosed under the PJM tariff, but the PUCO has taken a different view of what the state mechanism is:

> [I]n light of the change proposed by [AEP], the Commission will now expressly adopt as the state compensation mechanism for the Companies the current capacity charges established by the three-year capacity auction conducted by PJM, Inc. during the pendency of this review.

PUCO Entry ¶ 4. The default wholesale rate under the PJM tariff—barring any state compensation mechanism—is the RTO zone capacity clearing price in the corresponding RPM base residual auction. The PUCO has stated that it "approved retail rates for [AEP-Ohio], including recovery of capacity costs through provider-of-last-resort charges to certain retail shopping customers, based upon the continuation of the current capacity charges established by the three-year capacity auction conducted by PJM." *Id.* Thus the PUCO has ordered that—at least while its review is pending—the POLR Rider *plus* wholesale charges based on auction clearing prices combine to be the state capacity compensation mechanism.

The PUCO's statement certainly removes any doubt at FERC about *whether* a state compensation mechanism is in place, but we respectfully disagree with the PUCO's finding that the *wholesale* auction prices constitute the *retail* capacity compensation mechanism. Rather, the POLR Rider itself is the state capacity mechanism.

With the POLR Rider mechanism in place, AEP has not had the option under the PJM tariff to seek an additional wholesale capacity rate under its FRR plan, regardless whether the wholesale rate was based on auction results or was cost-based. It has thus been error for AEP to be to date "receiving capacity compensation from Ohio CRES Providers based on the RPM clearing price mechanism." November 24 Filing at 3. Since Ohio already has a compensation mechanism in place, AEP has had no entitlement to any wholesale recovery and has been improperly receiving this additional money. We requested at FERC that these amounts should be refunded to CRES Providers immediately.

E. AEP-Ohio Has Other PUCO-Approved Retail Mechanisms to Recover Capacity Costs

Finally, the POLR Rider is not the only retail mechanism by which AEP-Ohio collects capacity revenues. AEP-Ohio's retail rate includes an Environmental Investment Carrying Cost Rider, which is designed "to keep [AEP-Ohio's] fleet of generating facilities in operation." Baker Testimony at 24:13-14; *see also* PUCO Rate Order at 24–28. As Dr. Shanker explains:

> This charge was for all incremental environmental mitigation costs not otherwise captured in existing rates. Again this is clearly a capacity related retail charge applied to all customers, including those participating in retail access. This is a very material charge and is set at approximately 4.553% of non-energy generation costs, again indicating these are explicitly capacity related.

Shanker Affidavit ¶ 18. AEP-Ohio's FERC filing never mentions this retail charge.

There likely are other retail programs in place that similarly compensate AEP-Ohio for capacity. As part of this review, AEP-Ohio should be required to identify and itemize all of the costs that it collects in retail rates, and as set forth in detail in the next section, all of the other capacity revenues that AEP-Ohio receives. The PUCO can then determine whether AEP-Ohio is entitled to any additional capacity compensation. But one thing is clear: with state compensation mechanisms in place, AEP-Ohio may not go to FERC for additional compensation.

And, AEP-Ohio has to date not justified any prudent capacity recovery beyond what it is already collecting in PUCO-approved retail rates.

II. AEP-OHIO HAS FAILED TO SHOW THE DEGREE TO WHICH IT IS ALREADY RECOVERING ITS CAPACITY COSTS AND WHETHER THE NEW WHOLESALE CHARGE WOULD RESULT IN DOUBLE-RECOVERY

AEP-Ohio filed its proposed wholesale rates at FERC without making any showing that it was not already recovering all of its appropriate capacity costs in other rates and agreements.

The PUCO must require AEP-Ohio to come forward with sufficient evidence that it is not only entitled to additional recovery of prudently incurred costs, but also that there would be no double-recovery of any costs.

While we do not have access to the necessary information to demonstrate that AEP-Ohio is over-recovering—or that it would over-recover if the proposed rate went into effect—we do know that AEP-Ohio has to date omitted any explanation for how it is accounting for the amounts that it is already recovering in other rates and agreements. We discuss those other sources of revenue here but, in any case, more information from AEP-Ohio is needed.

A. *AEP Has Improperly Assumed that the PJM Tariff Entitles It to a Capacity Charge Based on Fully Embedded Costs*

As an initial matter, before we can begin to look at the costs that AEP-Ohio is already collecting and what additional costs—if any—that it might be entitled to, we must first analyze what capacity costs generators are currently permitted to recover in the RPM program. AEP-Ohio has apparently assumed that it is entitled to charge its fully embedded costs as part of the wholesale capacity charge. AEP-Ohio has offered no justification or discussion for why it makes this assumption. The RAA states that "the basis for compensation" may be changed under certain conditions from a market-based default "to a method *based on* the FRR Entity's *costs* or such other basis shown to just and reasonable." RAA, Schedule 8.1, Section D.8 (emphasis added). It is incorrect to assume that "just and reasonable" in this context means or even implies recovery of fully embedded costs. *See* Shanker Affidavit ¶ 20.

Fully embedded cost is the measure of all short-term and long-term costs necessary to keep a unit in service, including a return on capital. In the RPM construct, generators are mitigated and expressly not allowed to bid their fully embedded costs. Instead, each generator is limited to bidding its short run marginal costs, which are also known as incremental "to go" costs, or the "avoidable cost rate" ("ACR"). *See id.* ¶ 22. "These costs reflect the incremental costs that would be incurred by a Capacity Resource to stay in operation for an additional year as compared to mothballing or retirement, less the net income or margins that the unit could earn from the energy markets." *Id.*

The costs permitted to be included in the ACR calculation are strictly defined and regulated by the market monitor. *See id.* ¶ 22 & n.19. As Dr. Shanker explains:

> The components of the ACR are also specified in the PJM tariff and include avoidable operations and maintenance labor; avoidable administrative expenses; avoidable maintenance expenses; avoidable variable expenses; avoidable taxes and insurance; avoidable carrying charges; avoidable corporate level expenses; and avoidable project investment recovery rate/expense (APIR) for incremental necessary investment. The [market monitor's] worksheet and tariff provide greater detail regarding the actual elements of the conceptual incremental "to go" costs.
>
> Most notably the ACR does not include a return on and of original capital investment, but does allow for the inclusion of necessary incremental investments. As a marginal capital cost, it is the building block for capacity sell offers to establish a market-based rate in a locational clearing auction, where each supplier then receives the locational clearing price. Long term, inframarginal rents earned under such a clearing mechanism are intended to be compensatory for capital costs.

Shanker Affidavit ¶¶ 22–23 (footnote omitted).

To date, no capacity supplier in PJM has been permitted to bid above ACR. Most winning bidders in the RPM auctions will not be marginal (*i.e.*, their ACR will be less than the clearing price), and thus will earn some contribution to fixed costs in the RPM clearing price. *See id.* ¶ 24. This is not, however, the same as being guaranteed recovery of fully embedded costs, as AEP-Ohio sought at FERC. No generator in RPM would ever get anything like that guarantee.

As Dr. Shanker explains, the FRR construct should not grant greater wholesale compensation rights than the RPM construct:

> While FRR entities have essentially opted out of the RPM, conceptually, the rates under consideration here should effectively replicate the effect of the RPM. Presumably that is what was intended in the default pricing mechanism for an FRR entity in a retail choice state, which was set to the RPM pricing in the RAA. That would be the expected market proxy for AEP, had it participated in the overall RPM capacity market, or if seen from a slightly different perspective, the opportunity cost for sales from any eligible party of additional resources into the RPM auctions. Similarly in establishing the competitive retail offer for comparison to its own rates in the justification for its own rate filing, AEP developed a comparable full requirements rate, building from the RPM auction results for the relevant time periods. All these parallels suggest that an appropriate measure of cost for these rates should if not equal, at least mirror, the RPM's notion of cost.

Id. ¶ 21 (footnote omitted); *see also id.* ¶ 25 (discussing the justification for the RAA default rate in a retail choice state set at auction clearing prices).

In short, the RPM construct is not intended to set the value that a utility needs to collect from retail suppliers to make the utility whole. In RPM, generators are mitigated and can only bid their short run marginal costs. With this in mind, there was no basis for AEP-Ohio to assume that it had the right as an FRR entity to recover fully embedded costs, yet that is apparently what it sought at FERC. There is also no basis for the PUCO to assume that the FRR program entitles AEP-Ohio to recovery of fully embedded costs. AEP-Ohio must show its total revenue requirement and support it at the PUCO, and cannot include costs that would not be recoverable for similarly situated RPM resources.

B. *AEP Has Failed to Demonstrate That It Is Not Already Recovering Its Allowable Capacity Costs in Other Rates*

After starting too high, AEP-Ohio then failed to account for all of the capacity costs that it is already recovering. AEP-Ohio already has several rates and agreements in place to recover capacity costs. As part of this review, AEP-Ohio must show all of the sources of capacity revenue that it is already collecting and how these would be deducted from the wholesale rate that it proposed to charge.

In this section, we address all of the potential revenue sources that we are aware of. There may be others, but this would have to be examined in discovery, or the PUCO would have to require a comprehensive list, particularly since AEP has not disclosed this information.

1. Ohio POLR Revenue Requirement and Other Retail Rate Provisions

We have already discussed the POLR Rider and other retail rates that AEP-Ohio is currently recovering and have argued that these mechanisms preclude any wholesale recovery. *See supra* at 8 to 13. But to establish a revenue requirement, at a minimum, AEP-Ohio must account for the capacity revenues that it is already earning under these retail mechanisms. The PUCO approved an annual POLR revenue requirement in the amount of $97.4 million for Columbus Southern Power Company and $54.8 million for Ohio Power Company. *See* PUCO Rate Order at 40; *see also* Shanker Affidavit ¶ 17 (discussing amount of rider). AEP must also account for the Environmental Investment Carrying Cost Rider, which is designed "to keep [the AEP Ohio Companies'] fleet of generating facilities in operation." Baker Testimony at 24:13-14; *see also* PUCO Rate Order at 24–28. If there are any other retail mechanisms that permit recovery of any costs associated with capacity, AEP-Ohio must also account for these revenues as credits to its total approved revenue requirement.

2. AEP Interstate Pooling Agreements

AEP-Ohio has other sources of capacity revenue besides what it collects in retail rates. These include AEP's longstanding pooling agreements to pool costs and power across its multi-state service territory. The "AEP Interconnection Agreement," also known as the "AEP East Pool Agreement," coordinates behavior among AEP's eastern affiliates, including Columbus Southern Power Company and Ohio Power Company, and other affiliates. Ohio Power Co., Rate Schedule FERC No. 23, last supplemented by *Am. Elec. Power Serv. Corp.*, Docket No. ER96-2213-000, Modification No. 1 to the AEP System Interim Allowance Agreement (June 24, 1996), approved by FERC in *Am. Elec. Power Serv. Corp.*, Docket No. ER96-2213-000, Letter Order (Aug. 30, 1996). AEP also has another pooling agreement, the System Integration Agreement, which provides for similar arrangements. American Electric Power Service Corporation, Substitute Rate Schedule FERC No. 20 ("System Integration Agreement"), attached to *Am. Elec. Power Serv. Corp.*, Docket No. ER06-625-000, Amendments to Two Jurisdictional Agreements (Feb. 10, 2006), approved by FERC in *Am. Elec. Power Serv. Corp.*, Docket No. ER06-625-000, Letter Order (Mar. 24, 2006).

Among other provisions, these agreements provide for the transferring and sharing of revenues between AEP's affiliates. The AEP East Pool Agreement includes a "primary capacity equalization charge" related to capacity surpluses. *See* AEP East Pool Agreement at Article 6.2. The System Integration Agreement includes provisions on the "allocation of capacity costs and purchased power costs." *See* System Integration Agreement at Schedule A (Original Sheet Nos. 31–32). AEP-Ohio nowhere in its FERC filing mentions these arrangements or their effect on its proposed rate.

That was unacceptable and far from just and reasonable. As Dr. Shanker explains in discussing these agreements:

> While it is not entirely clear to me how to track the impacts of departing retail customers on energy and capacity obligations and charges under this agreement, it is likely that some may result in the equivalent of a retail capacity charge component. Again, this is simply unknown, and a necessary piece of information that [FERC] must have in order to make any determination with respect to first whether there is any need to implement the proposed AEP capacity charge, and second, if such charge is just and reasonable.

Shanker Affidavit ¶ 19.

3. PJM Reliability Assurance Agreement

AEP-Ohio also recovers significant capacity costs under its FRR plan. AEP-Ohio must demonstrate that Columbus Southern Power Company and Ohio Power Company are really only charging an appropriate share of their costs to the CRES Providers.

It is also unclear what generation AEP-Ohio sought to include in its proposed wholesale rate. Is it seeking recovery for all of its generation, or just the resources needed to meet its FRR obligation? If AEP has 30,000 MW of generation, but only a 25,000 MW Fixed Resource Requirement, the proposed rate should be based solely upon the amount needed for AEP-Ohio's FRR obligation, to the extent that it is not already recovered elsewhere.

In addition, AEP's FRR plan is system-wide (for all of AEP territories in PJM). Here, however, AEP-Ohio is proposing a new FRR rate for only one of its PJM states, Ohio. AEP-Ohio has not shown how it is separating the costs of Ohio generation under its FRR plan. Its proposal appears to discriminate against Ohio customers.

4. Wholesale Market Revenues

AEP-Ohio also needs to account for the revenues that it is collecting in other PJM markets. As Dr. Shanker explains, energy and ancillary services (E&AS) revenues should be deducted from capacity collections:

> If AEP no longer is supplying energy to a departing customer, but retains some capacity obligation, it is now free to sell its energy in the market and retail full energy margins/profits. If the intent is to "keep AEP whole" from the retail access departure, one would expect that such energy margins would be credited against any full embedded cost recovery. While this concept is simple in theory, it is more complicated in application. Effectively the earned energy margin on every AEP unit would have to be determined. One could argue that the departing customer is entitled to a credit reflecting either the average or marginal E&AS offsets from the AEP generation portfolio. I do not offer any opinion here as to which approach to the adjustment would be preferable. However, not even attempting to calculate E&AS offsets would necessarily result in a windfall to AEP via the maintenance of full capacity embedded cost revenues as well as all energy margins associated with that capacity.

Shanker Affidavit ¶ 28.

Dr. Shanker also explains that there "should be an opportunity cost offset" in the event that AEP-Ohio can "sell additional capacity either into PJM via the incremental auctions, or sell in-year replacement capacity, or sell such excess capacity outside of PJM." *Id.* ¶ 31. AEP-Ohio has not discussed these issues at FERC or elsewhere. *See id.* ¶ 32 (pointing out logical trap in AEP's likely treatment of opportunity costs).

5. Other

There likely are other categories of cost recovery that apply but that AEP-Ohio has not disclosed, let alone discussed. These could include revenues from off-system sales, netting due to self-supply by a CRES Provider, and others. Again, these are revenues that must be accounted for and subtracted from any approved revenue requirement.

C. AEP Has Failed to Justify Numerous Inputs

Finally, AEP-Ohio has not shown that the cost inputs to its proposed wholesale rate are just and reasonable. AEP-Ohio spent less than a single page in its FERC filing discussing "specific formula components," only calling out Construction Work in Progress (CWIP), Post-Employment Benefits other than Pensions (PBOPs) and Post Employment Benefits (PEBs) and ROE (11.1%). *See* November 24 Filing at 5. In each example, AEP-Ohio cited precedent from recent FERC cases where the inputs were non-controversial and much less was at stake. There were no adverse comments filed in any of those cases. AEP has provided no other explanation for why these inputs are appropriate for its proposed wholesale rate.

III. THE PROPOSED RATE WILL SIGNIFICANTLY IMPEDE RETAIL CHOICE IN OHIO

AEP-Ohio's proposed charge—if approved—would severely impede retail choice in Ohio and undercut demand response efforts. AEP-Ohio has discussed none of these issues, but even if it had, it could not show that its proposal would lead to just and reasonable outcomes.

First, the effect of AEP-Ohio's proposed rate on retail choice in Ohio would be devastating. *See generally* Shanker Affidavit ¶¶ 35–40. CRES Providers paid RTO clearing prices of $102/MW-day for the 2009/2010 delivery year. AEP-Ohio's rate proposal used 2009 numbers and produced a rate of $388/MW-day. *See* November 24 Filing, Attachment A, Part 1, at 1. In addition, RTO clearing prices were $16.46/MW-day for the 2012/2013 delivery year, and $27.73/MW-day for the 2013/2014 delivery year. Thus the new charge is 4 times higher than what CRES Providers paid in the 2009/2010 delivery year, and *nearly 25 times higher* than what providers are currently set to pay in the 2012/2013 delivery year.

AEP-Ohio's rate is also higher than any RPM clearing price in any zone to date. And it is over 15% higher than the 2013/2014 rest-of-pool value for the gross cost of new entry for ICAP (which is $335/MW-day). Thus, it would be cheaper in theory for CRES Providers to build a new fleet of peaking units than it would be for them to pay AEP-Ohio's rate.

The proposal is discriminatory against retail choice. The capacity components of the retail rate that AEP-Ohio charges to its own customers are much less than the wholesale rate that AEP-Ohio proposes here. CRES Providers will have no choice but to buy capacity from AEP-Ohio at the higher wholesale rate. They will be unable to compete with AEP-Ohio's retail rate. *See* Shanker Affidavit ¶ 6.

It does not take an economist to figure out what a 25-fold increase in capacity costs in a wholesale rate will do to interest in retail choice in AEP-Ohio's service territory. It likely would vanish.

Second, AEP-Ohio's sudden rate increase will likely have similarly negative effects on demand response. At a threshold level, it is unclear how demand response providers will be compensated when there are dueling wholesale and retail rates for capacity in Ohio. PJM cannot compensate one class of demand response providers at the RTO clearing price and another class of CRES Providers at a different price. AEP-Ohio also has not explained what would happen if a demand response provider oversupplied. Would AEP-Ohio pay the demand response provider back its alleged avoided costs at AEP's $388/MW-day rate? AEP-Ohio has not addressed these issues.

Third, it would also be bad for the market design if FRR entities could toggle between market-based and cost-based compensation in retail choice states. The PJM tariff is silent about the issue of when an FRR entity can switch back from cost-based to market-based recovery. This was likely an oversight, as the PJM tariff *is* clear that FRR resources cannot toggle between RPM and FRR. *See* RAA, Schedule 8.1(C)(1) (FRR "election shall be for a minimum term of five consecutive Delivery Years" and election can only be made "[n]o less than two months before the conduct of the Base Residual Auction for the first Delivery Year for which such election is to be effective," *i.e.*, over three years in advance). It would be unreasonable to permit AEP-Ohio to switch back to market-based recovery as soon as clearing prices go up, for example. The FERC has clearly held that this sort of toggling in the capacity markets risks over-recovery:

> [I]t is not reasonable to allow a resource that will remain in the capacity market in future years to toggle between cost-based and market-based compensation since a resource that could receive market prices when they exceed its costs and cost-based prices in the other years would be virtually guaranteed to earn revenues above costs over time. Providing a resource with a cost-based backstop would also blunt incentives for the resource to minimize its costs.

ISO New England Inc., 125 FERC ¶ 61,102 at PP 45–46, *order on clarification*, 125 FERC ¶ 61,324 (2008), *order on reh'g and clarification*, 130 FERC ¶ 61,089 (2010). It is equally unfair to let an FRR entity know what clearing prices are going to be in the three-year forward auction and then to switch to cost-based recovery if it does not like the market clearing price. That decision should be made prior to the base residual auction. CRES Providers, of course, have to make this decision before the base residual auction. AEP-Ohio thus would grant itself an option that CRES Providers would not have—to change the basis for compensation after the auction is run.

Finally, the requested implementation date of AEP-Ohio's proposed rate at FERC will also impede retail choice in Ohio. AEP-Ohio sought a January 1, 2011 effective date for its new rate. That date was seven months into the current 2010/2011 delivery year, which runs from June 1, 2010 to May 31, 2011. It was also over three years after the base residual auction was run for the 2010/2011 delivery year. Given reliance interests on existing rates, no rate should go into effect mid-delivery year. Indeed, the earliest reasonable date for any new rate to go into effect would be June 1, 2014, which is the beginning of the delivery year corresponding with the next three-year forward auction in PJM.

CRES Providers have entered into retail transactions and agreements for the period through the 2013/2014 delivery year based on AEP-Ohio's existing capacity charges. In addition, POLR auctions have already occurred for early 2011 based on the assumption that the capacity price would be the rest-of-pool clearing price.

It is unjust and unreasonable to change the cost of capacity after the fact, as AEP-Ohio proposes. The CRES Providers' past commitments cannot be undone. The question whether the new rates can be passed through depends on the CRES providers' agreements. But even if an agreement provides for pass-through, customers become dissatisfied with unexpected cost increases of this magnitude, particularly if AEP-Ohio and its merchant affiliate are not being charged the same rate.

The CRES Providers' reliance interests in this case are similar to PJM market participants' reliance interests on base residual auction results. Under RPM, capacity costs are transparent three years forward at the conclusion of the base residual auction. The final capacity price (reliability charge) changes only slightly (if at all) to reflect changes in the load forecast. To be fair, CRES Providers need to know the capacity price information that they will be charged—if prices will be different than RPM prices—before a base residual auction, in order to make an informed economic decision about whether to exercise their right to opt out of the FRR Plan. This self-supply right is granted to retail choice providers in the PJM tariff, just as it is to AEP-Ohio. But just like for AEP-Ohio, the self-supply right must be exercised before the base residual auction, *i.e., over three years before the delivery year.*

At this point, it is impossible for FirstEnergy and other CRES Providers to self-supply until the 2014/2015 delivery year. Without some delay or other relief, CRES Providers would be trapped into paying AEP-Ohio's new, much higher rate with no recourse, assuming that it is approved. This looks a lot like a classic bait and switch.

We have sought relief on this issue at FERC, but the PUCO should also be aware of the timing issues associated with any new capacity charges by AEP-Ohio and the discriminatory effect that they could have on CRES Providers and retail choice in Ohio.

In sum, AEP-Ohio's proposed rate cannot be approved unless AEP-Ohio can show that its proposal will not cause these unjust and unreasonable outcomes.

CONCLUSION

For the foregoing reasons, FirstEnergy respectfully requests that the PUCO reject any recovery by AEP-Ohio of capacity charges beyond those currently collected in the POLR Rider and other retail rate mechanisms. No additional recovery should be considered unless and until AEP-Ohio supports its total capacity revenue requirement with evidence and then accounts for all capacity charges that it is already collecting.

Respectfully submitted,

John N. Estes III
Paul F. Wight
SKADDEN, ARPS, SLATE, MEAGHER & FLOM LLP
1440 New York Avenue, N.W.
Washington, DC 20005
(202) 371-7000

Counsel for FirstEnergy Solutions Corp.

Mark A. Hayden (#0081077)
FirstEnergy Service Company
76 South Main Street
Akron, OH 44308
(330) 761-7735

January 6, 2011

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company	)))	Case No. 10-2929-EL-UNC

CERTIFICATE OF SERVICE

I hereby certify that I have on this day caused to be served a true and correct copy of the foregoing Comments of FirstEnergy Solutions Corp. via electronic mail (when available) and by first-class postage prepaid mail, to all parties on this 6th day of January, 2011.

*David C. Rinebolt
Ohio Partners for Affordable Energy
231 W Lima St PO Box 1793
Findlay, OH 45840-1793
drinebolt@ohiopartners.org

Jody M. Kyler
Ohio Consumers Counsel
10 West Broad St., Suite 180
Columbus, OH 43215
kyler@occ.state.oh.us

Samuel C. Randazzo
Joseph E. Oliker
McNees Wallace & Nurick LLC
21 East State Street, 17th Floor
Columbus, OH 43215
sam@mwncmh.com
joliker @ mwncmh.com

David Boehm
*Michael L. Kurtz
Boehm, Kurtz & Lowry
36 E. Seventh St., Suite 1510
Cincinnati, OH 45202
dboehm@BKLlawfinn.com
nikurtz@BKLlawfirm.co

*Indicates that party has agreed to be automatically served via electronic mail.

Dated at Washington, D.C., this 6th day of January, 2011.

Paul F. Wight
SKADDEN ARPS SLATE MEAGHER & FLOM LLP
1440 New York Avenue, N.W.
Washington, DC 20005
Paul.Wight@skadden.com
(202) 371-7323

ATTACHMENT A

Affidavit Of Roy J. Shanker Ph.D.
On Behalf Firstenergy Service Company

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection L. L. C.	)	Docket No. ER11-2183-000

AFFIDAVIT OF ROY J. SHANKER PH.D.
ON BEHALF FIRSTENERGY SERVICE COMPANY

I. INTRODUCTION AND SUMMARY OF CONCLUSIONS

1. My name is Roy J. Shanker.[1] I have been asked by counsel for FirstEnergy Service Company (FE or FirstEnergy)[2] to review the November 24, 2010 filing of the American Electric Power Service Corporation (AEP) in this docket. In that filing, AEP sought to increase the capacity price it charges Competitive Retail Electric Service Providers (CRES Providers) operating within the footprint of AEP's Fixed Resource Requirement area in Ohio.

2. I reviewed the AEP Filing, the PJM Tariff and Reliability Assurance Agreement (RAA) and documents related to the retail rate arrangements in Ohio for AEP's Ohio affiliates, Columbus Southern Power Company and Ohio Power Company (collectively, the "AEP Ohio Companies"). I conclude that AEP has failed to adequately justify and support the proposed capacity compensation formulae and

[1] I have extensive experience spanning 37 years in the electric utility industry and have been an active participant in the development of formal organized wholesale markets since 1995. In all of these markets the issues related to the design and compensation for capacity markets has been a continuing activity in the stakeholder process in which I have been an active participant. Specifically with respect to the Reliability Pricing Model (RPM) in PJM I have testified numerous times before the Commission, participated in Technical Sessions both at the Commission and at PJM, and participated in the settlement discussions which developed the relevant provisions that are the basis for the instant proceeding. I also specifically commented on the Fixed Resource Requirement (FRR) concepts in a related Technical Session at the Commission in June of 2006. A summary of my experience is attached as Exhibit A to this affidavit.

[2] FirstEnergy Service Company submits this pleading on behalf of its power marketing affiliate FirstEnergy Solutions Corp. (Solutions).

related charges. *First*, AEP already has approved Ohio rates to collect capacity costs, and thus under the plain provisions of the RAA, AEP has no right to file for an additional wholesale charge.

3. *Second*, even if AEP had the right under the RAA to file, it has improperly sought its full, unadjusted, embedded cost of capacity for all generation resources. PJM's capacity markets have never been set up to guarantee this level of recovery. Instead, they are designed to compensate for the short-term marginal costs of existing facilities (referred to as the avoidable cost rate (ACR)) and the long run marginal net costs of new entry for a peaking unit via the use of a clearing auction structure and sell offers reflecting marginal "to go" costs or net costs of new entry.

4. *Third*, even if one ignores the potential for double collection and the existence of a related retail charge, and for the sake of argument adopts a full embedded cost standard in this situation, the appropriate rate methodology would still need to be offset by revenues from other markets (energy and ancillary services, or E&AS) and opportunity costs of incremental capacity sales allowed by the departing customer. The relative change of load between a CRES Provider in Ohio and Provider of Last Resort (POLR) customers may also affect revenues under the AEP pooling agreements.

5. Thus, logically, AEP must clarify whether it can sell incremental capacity, as it must stand ready as a POLR provider while receiving associated retail income as anticipated by the RAA, or whether it can sell capacity associated with departing customers and should make provision for the incremental income from these sales in its claimed recovery rate. Whatever the answer, it is clear that AEP is either

ineligible for the proposed capacity rate due to existing state tariffs, or has submitted an inappropriate rate design. Similarly, AEP also has to account at least for any E&AS offsets, opportunity or real costs from capacity sales and company pooling agreements.

6. Based on my review, I also conclude that the imposition of AEP's proposed capacity charges on such short notice will necessarily freeze or even eliminate competitive retail access in Ohio and have an associated anti-competitive impact on competition in retail markets. The action smacks of anti-competitive behavior to raise a material barrier to entry for competitive suppliers vying for AEP's existing retail customers.

7. The PJM capacity markets work on a three-year forward basis. AEP is proposing to implement this rate at the beginning of 2011, in the middle of the 2010-11 capacity planning year, where capacity prices were set three years ago. While PJM does allow parties within an FRR region (such as AEP) the alternative to meet their own supplies,[3] this option is only available on a prospective basis. This means the first opportunity would be in this spring's auction process for the 2014-15 planning year. As a result, AEP's action effectively has competitive suppliers trapped into paying a proposed \$388/MW-day in a market where the last measure of capacity value was approximately \$28/MW-day, and the current charge by AEP to competitive suppliers for capacity is approximately \$102/MW-day.

8. AEP's right to seek compensation for its embedded costs is not under question here. What I do question is the propriety of what is effectively retroactive application of the rates, in the presence of other Ohio retail recovery mechanisms and the serious

[3] RAA, Schedule 8.1, Section D.9.

concerns this raises for competition at the retail level. This will chill retail access and can be presumed not to have been part of the intent of designers and administrators of the Ohio retail access programs.

9. Again it would seem that the filing is deficient in (a) not fully representing to the Commission how such charges work in the overall retail competitive scheme put in place by the Public Utilities Commission of Ohio (PUCO or Ohio Commission) and (b) missing material factual evidence needed to assess the correct basis, if any, for such charges. Thus not only does AEP fail to support the rate, but the introduction of such charges would have a clearly stifling impact on state jurisdictional retail access programs.

II. THE COMMISSION LACKS SUFFICIENT INFORMATION TO DETERMINE WHETHER AEP'S PROPOSED RATES ARE JUST AND REASONABLE

10. The proposed filing is simply too deficient in multiple areas to allow for any determination by the Commission about whether the proposed capacity charges for departing retail access customers are just and reasonable. There are too many unanswered questions that may have a material impact on whether the rate should even be allowed in the first place, and if allowed, what constitutes the proper determination of the applicable rate. It would seem that at minimum there is a need for extensive documentation and discovery to determine the appropriateness of the proposed capacity rates. I identify at least three general issues that in the first instance suggest the inappropriateness of the AEP proposal, and at a minimum point out the serious lack of supporting information regarding material issues that the Commission must consider: (1) AEP has not demonstrated a right to file for cost-based rates, (2) AEP proffers an interpretation of "cost" that is incompatible with the

RPM design, and (3) the use of full embedded cost recovery would be inappropriate. I discuss these in turn.

A. AEP Has Not Demonstrated a Right to File for Cost-Based Rates

11. AEP predicates its filing of a full embedded cost rate on the provisions of the PJM RAA:

> In the case of load reflected in the FRR Capacity Plan that switches to an alternative retail LSE, where the state regulatory jurisdiction requires switching customers or the LSE to compensate the FRR Entity for its FRR capacity obligations, such state compensation mechanism will prevail. *In the absence of a state compensation mechanism*, the applicable alternative retail LSE shall compensate the FRR Entity at the capacity price in the unconstrained portions of the PJM Region, as determined in accordance with Attachment DD to the PJM Tariff, provided that the FRR Entity may, at any time, make a filing with FERC under Sections 205 of the Federal Power Act proposing to change the basis for compensation to a method based on the FRR Entity's cost or such other basis shown to be just and reasonable.[4]

12. Thus the triggering condition is whether there is an applicable Ohio retail rate that addresses payments for capacity for retail access customers. This is a condition precedent to being able to seek a payment other than retail rates or the default RPM rate. In its filing, AEP explicitly states that "Ohio has not established a compensation mechanism for capacity sales."[5] My understanding is that up to now AEP has provided capacity and charged departing retail customers the RTO RPM clearing price.

13. With this in mind I reviewed recent AEP retail rate cases and associated testimony, filings and orders from the Ohio Commission. My review indicates that AEP's

[4] RAA, Schedule 8.1, Section D.8 (emphasis added).

[5] AEP Filing at 3.

statement is misleading at best. There are at least two explicit capacity related charges linked to either all customers or retail access customers. There may be other aspects of AEP's rates that may have a similar effect. Thus the conditions precedent for the filing are not met.

14. I emphasize that it is not necessary that the existing Ohio retail rates be fully compensatory. This is an issue for the Ohio Commission to address, and which they should address in the context of their overall retail rate program. However, what is relevant is that the existence of such charges eliminates the "trigger" that AEP cites from the PJM RAA.

15. The first retail rate that I identified that addressed such capacity compensation is the POLR Rider that AEP applies to all customers in the service territories of both Ohio Power Company and Columbus Southern Power Company.[6]

16. In testimony before the Ohio Commission, AEP witness J. Craig Baker stated with respect to the potential for customers to depart and return to the system under retail access:

> This flexibility [to leave and return] leaves the Companies in the precarious position of being exposed to losing generation service load when the market price is low but needing to stand ready to begin serving that load again when the market price is high, and in the case of a CRES or other supplier default, doing so at a moment's notice. There is a definite and significant cost associated with providing this flexibility. In addition to the challenges of *providing capacity and energy* on short notice, the Companies would provide service to returning customers at

[6] *See In re Application of Columbus S. Power Co.*, PUCO Case Nos. 08-917-EL-SSO & 08-918-EL-SSO, Opinion and Order at 38–40 (Mar. 18, 2009) (PUCO Opinion).

> the SSO rate (even though they are likely to be returning because market prices exceed the SSO).[7]

17. The Ohio Commission approved a revenue requirement for such POLR liability, charged to all customers[8] of the AEP Ohio Companies of $97.4 million for Columbus Southern and $54.8 million for Ohio Power.[9] Associated with this revenue requirement was the implementation of the non-bypassable POLR Rider. It seems unambiguous that there is in place a charge related to capacity liability for departing retail customers. Also, my understanding is that when specified as a revenue requirement, such amounts will be fully recoverable.[10]

18. Similarly, the AEP Ohio Companies charge all customers an Environmental Investment Carrying Cost Rider. As Mr. Baker explained in his testimony, this charge to all customers relates to the obligation "to keep their fleet of generating facilities in operation."[11] This charge was for all incremental environmental mitigation costs not otherwise captured in existing rates. Again this is clearly a capacity related retail charge applied to all customers, including those participating in retail access. This is a very material charge and is set at approximately 4.553% of non-energy generation costs, again indicating these are explicitly capacity related.[12]

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[7] *In re Application of Columbus S. Power Co.*, PUCO Case Nos. 08-918-EL-SSO & 08-918-EL-SSO, Direct Testimony of J. Craig Baker on Behalf of Columbus Southern Power Company and Ohio Power Company at 27 (July 31, 2008) (Baker Testimony) (emphasis added).

[8] Municipal aggregation, and departing customers agreeing to pay "market rates" were exempted from this otherwise non bypassable charge.

[9] PUCO Opinion at 40.

[10] Note the PJM RAA requires an FRR plan to include capacity for all load within the FRR entity, including load growth. The interaction of this obligation, retail access, POLR charges, AEP pooling agreements, and other Ohio regulatory requirements for retail access all are unexplained.

[11] Baker Testimony at 24-25.

[12] *See, e.g.*, PUCO Opinion at 24-28.

19. Finally, there are revenue transfer provisions under the AEP pooling agreement and System Integration Agreement.[13] While it is not entirely clear to me how to track the impacts of departing retail customers on energy and capacity obligations and charges under this agreement, it is likely that some may result in the equivalent of a retail capacity charge component. Again, this is simply unknown, and a necessary piece of information that the Commission must have in order to make any determination with respect to first whether there is any need to implement the proposed AEP capacity charge, and second, if such charge is just and reasonable.

B. AEP Proffers an Interpretation of "Cost" Incompatible with the RPM Design

20. The pertinent passage that AEP relies upon from the RAA simply states: "for compensation to a method based on the FRR Entity's cost or such other basis shown to be just and reasonable."[14] The provision does not provide for the use of full embedded costs, nor does it define costs at all, nor does it restrict the development of such a rate solely to a cost-based rate. It only provides, as it should, that the substitute rate be just and reasonable.

21. In this context a reasonable inquiry is what is the intent of the capacity payment in the context of the overall PJM market design and the associated concepts that relate to capacity compensation in the market. While FRR entities have essentially opted out of the RPM, conceptually, the rates under consideration here should effectively

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[13] *See generally* Ohio Power Co., Rate Schedule FERC No. 23, last supplemented by *Am. Elec. Power Serv. Corp.*, Docket No. ER96-2213-000, Modification No. 1 to the AEP System Interim Allowance Agreement (June 24, 1996), approved by the Commission in *Am. Elec. Power Serv. Corp.*, Docket No. ER96-2213-000, Letter Order (Aug. 30, 1996); American Electric Power Service Corporation, Substitute Rate Schedule FERC No. 20, attached to *Am. Elec. Power Serv. Corp.*, Docket No. ER06-625-000, Amendments to Two Jurisdictional Agreements (Feb. 10, 2006), approved by the Commission in *Am. Elec. Power Serv. Corp.*, Docket No. ER06-625-000, Letter Order (Mar. 24, 2006).

[14] RAA, Schedule 8.1, Section D.8.

replicate the effect of the RPM. Presumably that is what was intended in the default pricing mechanism for an FRR entity in a retail choice state, which was set to the RPM pricing in the RAA. That would be the expected market proxy for AEP, had it participated in the overall RPM capacity market, or if seen from a slightly different perspective, the opportunity cost for sales from any eligible party of additional resources into the RPM auctions. Similarly in establishing the competitive retail offer for comparison to its own rates in the justification for its own rate filing, AEP developed a comparable full requirements rate, building from the RPM auction results for the relevant time periods.[15] All these parallels suggest that an appropriate measure of cost for these rates should if not equal, at least mirror, the RPM's notion of cost.

22. From this perspective the notion of using full embedded costs as proposed by AEP seems very inappropriate. In recognition of market power, currently all capacity offers in the entire PJM market are subject to *cost*-based mitigation. But these costs are well defined in the context of what is referred to as the avoidable cost rate or ACR. The ACR reflects the net incremental "to go" costs of a unit. These costs reflect the incremental costs that would be incurred by a Capacity Resource to stay in operation for an additional year as compared to mothballing or retirement, less the net income or margins that the unit could earn from the energy markets. The concept is not *ad hoc*, and while suppliers can accept default values developed by the PJM market monitor, the market monitor will calculate unit specific ACRs inclusive of the unit's own energy margins as an offset. The PJM market monitor, Monitoring

[15] Baker Testimony at 9-11.

Analytics, has posted online a sample ACR worksheet that shows the depth of "cost" detail engaged in by PJM in determining the appropriate cost-based mitigation concepts for capacity sell offers.[16] The components of the ACR are also specified in the PJM tariff and include avoidable operations and maintenance labor; avoidable administrative expenses; avoidable maintenance expenses; avoidable variable expenses; avoidable taxes and insurance; avoidable carrying charges; avoidable corporate level expenses; and avoidable project investment recovery rate/expense (APIR) for incremental necessary investment.[17] The worksheet and tariff provide greater detail regarding the actual elements of the conceptual incremental "to go" costs.

23. Most notably the ACR does not include a return on and of original capital investment, but does allow for the inclusion of necessary incremental investments. As a marginal capital cost, it is the building block for capacity sell offers to establish a market-based rate in a locational clearing auction, where each supplier then receives the locational clearing price. Long term, inframarginal rents earned under such a clearing mechanism are intended to be compensatory for capital costs.

24. The single-price auction mechanism will in many cases result in adequate financial returns to support the net cost of new entry. If captured, on average, such clearing prices are intended to provide adequate compensation for *all* capacity suppliers. By design this pricing is intended to supply the "missing money" related to pure capacity to *all* market participants. This conclusion applies to not only the reference peaking

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16 *See* http://www.monitoringanalytics.com/tools/tools.shtml and select "RPM-ACR Template version 10."

17 PJM Tariff, Attachment DD, Sections 6.7 & 6.8.

plant, but cycling and base load facilities as well. These concepts have been fully vetted and approved by the Commission on numerous occasions. This has specifically occurred with respect to the approval of demand curve based market designs relying on net costs of new entry. It is my understanding that these decisions have been upheld by the courts of appeals, regarding the designs in New York and PJM.

25. It is in this context that the FRR default rate, the RPM auction price, was set for the payments of capacity by departing retail customers under the FRR. With this background it can be seen that the default rate had two important properties. First, it was a good approximation of the opportunity cost that an FRR entity would face if it could sell any released capacity into the PJM markets, and second, the rate itself, on average and over time, should hold the same property as the intent of the long term average RPM prices, full recovery of the net cost of new entry. This net cost of new entry is the proper capacity pricing signal in any market-based design.

26. When seen in this light, and also now assuming existing state-related charges, AEP's selection of full embedded costs as its own interpretation of the term "cost" in the pertinent RAA provision is highly questionable. Though the provision itself offers no direct guidance, it would seem that cost concepts similar to or derived from the ACR cost components for AEP or the continued use of the RPM rates would be much more appropriate default rates, particularly on a retroactive basis where competitive suppliers are trapped without access to alternative capacity supplies. For example, while my first choice would be the continued use of the default RPM rate, I can envision alternatives that attempt to reflect what the RTO RPM rate might have been

with the inclusion of AEP resources at their ACR values, or some sort of marginal ACR for AEP on a stand alone basis. These types of metrics all seem more consistent with the overall market design than a default to full embedded costs. However, as AEP has never informed the Commission of any of these issues, it is impossible for the Commission to reach a determination of what is just and reasonable using the filing alone. Given my comments above, it would seem this cannot be the case.

C. Use of Full Embedded Costs Would Be Inappropriate

27. Even if one were to accept for the moment that a full embedded cost-based charge was the right general approach in the RPM construct instead of an equivalent to ACR, and that there were no other applicable state charges in place, the use of the full embedded cost of generation would still be incorrect. Such a value would have to be modified materially to remove any double collections and or conceptual misalignments. Again, AEP has provided no information sufficient to make the necessary modifications.

28. First, and most obvious, is that the charge needs to be modified to reflect the appropriate E&AS offset. If AEP no longer is supplying energy to a departing customer, but retains some capacity obligation, it is now free to sell its energy in the market and retail full energy margins/profits. If the intent is to "keep AEP whole" from the retail access departure, one would expect that such energy margins would be credited against any full embedded cost recovery. While this concept is simple in theory, it is more complicated in application. Effectively the earned energy margin on every AEP unit would have to be determined. One could argue that the departing customer is entitled to a credit reflecting either the average or marginal E&AS offsets from the AEP generation portfolio. I do not offer any opinion here as to which

approach to the adjustment would be preferable. However, not even attempting to calculate E&AS offsets would necessarily result in a windfall to AEP via the maintenance of full capacity embedded cost revenues as well as all energy margins associated with that capacity.

29. Further, such margins would have to be seen through the filter of any other retail or wholesale rate adjustments such as fuel factor provisions and pooling arrangements to further assure no over or under recovery. No information on any of this is presented, making it impossible to understand whether such a rate, even if legitimate in concept, is just and reasonable in execution.

30. While logically one might argue that some, if not all, of these adjustments might be subject to determinations of the Ohio Commission, this in and of itself should not be an impediment to AEP making the appropriate factual representations to the Commission as to the overall treatment of such margins, and how their proposal, if accepted, prevents double collections of this type. Forum shopping based on the use of the ambiguous term "cost" should not result in over-compensation. Nor should it be an excuse for incomplete documentation and disclosure. A knowledgeable third party should be able to determine the fundamental elements of the proposed rates without having to make dozens of assumptions and guesses. Such guesses are necessary here, and can only be rectified by a more thorough and complete filing and appropriate discovery.

31. Next, I would also expect that there would be or should be an opportunity cost offset to the recovery of full embedded capacity costs. While the RPM has a three-year forward period, and there are limitations on what AEP can sell into that market, in

principle it can sell additional capacity either into PJM via the incremental auctions, or sell in-year replacement capacity, or sell such excess capacity outside of PJM. I do not know if AEP is eligible to do this, or if it has done this, or if it has declined to even attempt such sales. I also do not know how such sales would "roll through" both Ohio and overall pooling arrangements. That I remain ignorant of this material fact after careful review of the AEP Filing once again indicts its incompleteness.

32. The Commission should note that the opportunity sale concept creates a true logical dilemma in the AEP Filing. If AEP were to adopt the position that it cannot sell excess capacity, for example, because it has to retain it for the departing customers, then presumably existing Ohio charges such as the POLR Rider and Environmental Carry Cost discussed above were put in place to be compensatory (as determined by Ohio) for this obligation, and AEP has no right to make the present filing. If, on the other hand, AEP were to take the position that it can sell its excess capacity, then they would be admitting that the filing is deficient as it has not demonstrated to the Commission what adjustments are appropriate to reflect the prudent disposition of this capacity.

33. Finally, as an empirical matter all of these changes have to go through the "filter" of the AEP pooling agreement among the member companies. It is not clear how, if at all, the agreement affects any change in capacity or energy revenues or obligations associated with retail access. Again this becomes a material issue of fact that is relevant to the Commission in reaching any determination as to the just and reasonable nature of the proposed rate.

III. THE PROPOSED RATE IS A BARRIER TO COMPETITION

34. Under the RPM design, FRR plans and designated resources are set three years in advance. Although LSEs within an FRR region have the option of supplying their own "mini" FRR under the provisions of the RAA, this too must be on a prospective basis.[18]

35. A CRES Provider with retail clients in an FRR region is at the mercy of the FRR supplier from the time the FRR supplier announces its new capacity rates to the end of the RPM's 3-year forward period. This would be the first opportunity, three years out, that a CRES Provider could attempt to put in place its own FRR plan. It is very difficult to see how retail access could develop reasonably in a situation where a major cost component is set and controlled by a third party—and often a principal competitor.

36. AEP too apparently expected little or no retail competition. As noted above, *supra* ¶ 21, when developing a competitive retail offer to represent what its expectation would be for a competitive full requirements offer versus its own proposed rates, AEP concluded that its proposed rates would be cheaper. In justifying its retail rates to the Ohio Commission, AEP had to make a comparison to what would be expected from a full requirements market-based offer from a third party. AEP concluded and represented to the Ohio Commission that its proposed rates would be less than market-based offers from a third party. AEP built up its own estimate of what a third party would have to bid to take over a full requirements customer. This estimate explicitly relied on estimates of capacity costs using the PJM RPM results. Overall,

[18] RAA, Schedule 8.1, Section D.9.

AEP concluded its retail rates would be lower than such a competitive retail offer. Presumably with this conclusion in hand, AEP continued not to anticipate material retail competition. It was in this environment, with the anticipated absence of any material competition from other LSEs, that AEP put forward its FRR plan, and continued with the use of the default RPM capacity charge for departing customers. Basically it appears that AEP was content with the status quo, so long as it entailed little or no competition.

37. It appears that this expectation has changed. Here, AEP has decided to increase the capacity price from the current approximately $102 to approximately $388/MW-day, an increase of 280%. Further, the last RPM auction set a price of approximately $28/MW-day for the 2013-14 planning year. In other words, AEP is demanding that retail consumers who wish to take advantage of competition pay a price for capacity almost 14 times higher than a comparable market price. This $388 price is even higher than the net cost of entry used in the last RPM auction ($318.95).[19] This means that the proposed new exit fee is 22% higher than the expected equilibrium charges for new capacity for the entire RTO region.[20]

38. At the very least, the Commission requires much more extensive and complete justifications for such facially aberrant charges. Increased retail departures unanticipated by AEP may lie at the heart of the change in pricing strategy. If so, it could become an important factor in the Commission's determination regarding the

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19 Monitoring Analytics, Analysis of the 2013/2014 RPM Base Residual Auction (July 14, 2010), http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2013_2014_RPM_Base_Residual_Auction_20100714.pdf. This report contains detailed summary information for the last auction and is available at monitoringanalytics.com under 2010 Reports.

20 In and of itself this presents an interesting perspective regarding claims that the overall PJM RPM charges are excessive.

acceptance, timing and level of the proposed rate, and ultimately whether it is just and reasonable.

39. The impact on retail access competition is obvious. Competitive LSEs are trapped with AEP's inflated costs until they have an opportunity in the next auction to put in place their own FRR zone.[21] They have likely relied on the RPM current and future (within the 3 year window) charges as the basis for their own business plans and hedging while competing for retail load in Ohio. They now face an approximately 4-fold to 14-fold higher capacity charges. Not only is the enormous increase in capacity charge itself an impediment, but the mere act of filing for such astronomical charges is likely to result in a near freeze of new competitive activity.

40. Because the chilling effect is so transparent and obvious, it would also seem that the Commission would like the input of the PJM Independent Market Monitor and the Ohio Commission regarding whether such pricing is consistent with the underlying wholesale and retail market designs, or whether it constitutes an exercise of market power over the trapped LSEs seeking to develop competitive retail access businesses.

41. This concludes my affidavit.

[21] It should be obvious that in doing so, the anticipated bilateral price for capacity would closely track anticipations regarding the RTO RPM price for the next auction, not AEP's claimed full embedded cost.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.) Docket No. ER11-2183-000

I, Roy J. Shanker, being duly sworn, depose and state that the contents of the foregoing Affidavit of Roy J. Shanker Ph.D. on behalf of FirstEnergy Service Company is true, correct, accurate and complete to the best of my knowledge, information, and belief.

Roy J Shanker

Roy Shanker

SUBSCRIBED AND SWORN to before me this _____ day of December, 2010.

____
(Notary Public)

My commission expires: ______________

State of California County of
Monterey
Subscribed and sworn to (or affirmed)
before me on this 7 day of December, 2010, by
Roy Shanker
proved to me on the basis of satisfactory evidence
to be the person(s) who appeared before me.
Signature Ramona L Nason
(Seal)

RAMONA L. NASON
Commission # 1816592
Notary Public - California
Monterey County
My Comm. Expires Oct 9, 2012

EXHIBIT A

QUALIFICATIONS
AND
EXPERIENCE OF

DR. ROY J. SHANKER

EDUCATION:

Swarthmore College, Swarthmore, PA
A.B., Physics, 1970

Carnegie-Mellon University, Pittsburgh, PA
Graduate School of Industrial Administration
MSIA Industrial Administration, 1972
Ph.D., Industrial Administration, 1975

Doctoral research in the development of new non-parametric multivariate techniques for data analysis, with applications in business, marketing and finance.

EXPERIENCE:

1981 - Present
Independent Consultant
P.O. Box 60450
Potomac MD 20854

Providing management and economic consulting services in natural resource-related industries, primarily electric and natural gas utilities.

1979-81
Hagler, Bailly & Company
2301 M Street, N.W.
Washington, D.C.

Principal and a founding partner of the firm; director of electric utility practice area. The firm conducted economic, financial, and technical management consulting analyses in the natural resource area.

1976-79
Resource Planning Associates, Inc.

1901 L Street, N.W.
Washington, D.C.

Principal of the firm; management consultant on resource problems, director of the Washington, D.C. utility practice. Direct supervisor of approximately 20 people.

1973-76 Institute for Defense Analysis
Professional Staff
400 Army-Navy Drive
Arlington, VA

Member of 25 person doctoral level research staff conducting economic and operations research analyses of military and resource problems.

RELEVANT EXPERIENCE:

2010

Federal Energy Regulatory Commission Docket RM10-17. Invited panelist addressing metrics for cost effectiveness of demand response and associated cost allocations and implications for monopsony power.

Federal Energy Regualtory Commission Consolidated Dockets ER10-787-000, EL10-50-000, and EL10-57-000. Two affidavits on behalf of the New England Power Generators Association regarding ISO-NE modified proposals for alternative price rule mitigation and zonal definitions/functions of locational capacity markets.

Federal Energy Regulatory Commission Docket No. ER10-2220-000. Affidavit on behalf of the Independent Energy Producers of New York. Addressing rest of state mitigation thresholds and procedures for adjusting thresholds for frequently mitigated units and reliability must run units.

Federal Energy Regulatory Commission Docket PA10-1. Affidavit on behalf of Entergy Services related to development of security constrained unit commitment software and its performance.

Federal Energy Regulatory Commission Docket No. ER09-1063-004. Testimony on behalf of the PJM Power Providers Group (P3) regarding the proposed shortage pricing mechanism to be implemented in the PJM energy market. Reply comments related to a similar proposal by the independent market monitor.

PJM RTO. Statement regarding the impact of the exercise of buyer market power in the PJM RPM/Capacity market. Panel discussant on the issue at the associated Long Term Capacity Market Issues Sympossium.

Federal Energy Regulatory Commission Docket No. ER10-787-000. Affidavit on behalf of New England Power Generators Association addressing proper design of the alternative price rules (APR) for the ISO-NE Forward Capacity Auctions. Second affidavit offered in reply. Supplemental affidavit also submitted

Federal Energy Regulatory Commission Docket No. RM10-17-000. Affidavit on behalf of New England Power Generators Association addressing proper pricing for demand response compensation in organized wholesale regional transmissiom organizations.

Federal Energy Regulatory Commission Docket No. RM10-17-000, Affidavit on my on behalf regarding inconsistent representations made between filings in this docket and contemporaneous materials presented in the PJM stakeholder process.

2009

Federal Energy Regulatory Commission Docket No. ER09-1682. Two affidavits on behalf of an un-named party regarding confidential treatment of market data coupled with specific market participant bidding, and associated issues.

American Arbitration Assoication, Case No. 75-198-Y-00042-09 JMLE, on behalf of Rathdrum Power LLC. Report on the operation of specific pricing provision of a tolling power purchase agreement.

Federal Energy Regulatory Commission. Docket No. IN06-3-003. Analyses on behalf of Energy Transfer Partners L.P. regarding trading activity in physical and financial natural gas markets.

Federal Energy Regulatory Commission. Docket No. ER08-1281-000. Analyses on behalf of Fortis Energy Trading related to the impacts of loop flow on trading activities and pricing.

American Arbitration Association. Report on behalf of PEPCO Energy Services regarding several trading transactions related to the purchase and sale of Installed Capacity under the PJM Reliability Pricing Model.

Federal Energy Regulatory Commission Docket No. EL-0-47. Analyses on behalf of HQ Energy services (U.S.) regarding pricing and sale of energy associated with capacity imports into ISO-NE.

Federal Energy Regulatory Commission Docket No.. ER04-449 019, Affidavit on behalf of HQ Energy Services (U.S.) regarding the implementation of the consensus deliverability plan for the NYISO, and associated reliability impacts of imports.

Federal Energy Regulatory Commission Docket ER09-412-000, ER05-1410-010, EL05-148-010. Affidavit and Reply Affidavit on behalf of PSEG Companies addressing proposed changes to the PJM Reliability Pricing Model and rebuttal related to other parties' filings.

2008

Pennsylvania Public Service Commission. *En Banc* Public Hearing on "Current and Future Wholesale Electricity Markets", comments regarding the design of PJM wholesale market pricing and state restructuring.

Maine Public Utility Commission. Docket No. 2008-156. Testimony on behalf of a consortion of energy producers and suppliers addressing the potential withdrawal of Maine from ISO New England and associated market and supplier response.

Federal Energy Regulatory Commission. Docket No. EL08-67-000. Affidavit on behalf of Duke Energy Ohio and Reliant Energy regarding criticisms of the PJM reliability pricing model (RPM) transitional auctions.

Federal Energy Regulatory Commission. Docket AD08-4, on behalf of the PJM Power Providers. Statement and participation in technical session regarding the design and operation of capacity markets, the status of the PJM RPM market and comments regarding additional market design proposals.

Federal Energy Regulatory Commission. Docket ER06-456-006, Testimony on behalf of East Coast Power and Long Island Power Authority regarding appropriate cost allocation procedures for merchant transmission facilities within PJM.

2007

FERC Docket No. EL07-39-000. Testimony on behalf of Mirant Companies and Entergy Nuclear Power Marketing regarding the operation of the NYISO In-City Capacity market and the associated rules and proposed rule modifications.

FERC Dockets: RM07-19-000 and AD07-7-000, filing on behalf of the PJM Power Providers addressing conservation and scarcity pricing issues identified in the Commission's ANOPR on Competition.

FERC Docket No. EL07-67-000. Testimony and reply comments on behalf of Hydro Quebec U.S. regarding the operation of the NYISO TCC market and appropriate bidding and competitive practices in the TCC and Energy markets.

FERC Docket Nos. EL06-45-003. Testimony on behalf of El Paso Electric regarding the appropriate interpretation of a bilateral transmission and exchange agreement.

2006

United States Bankruptcy Court for the Southern District of New York. Case No. 01-16034 (AJG). Report on Behalf of EPMI regarding the properties and operation of a power purchase agreement.

FERC Docket No. EL05-148-000. Testimony regarding the proposed Reliability Pricing Model settlement submitted for the PJM RTO.

FERC Docket No. ER06-1474-000, FERC. Testimony on behalf othe PSEG Companies regarding the PJM proposed new policy for including "market efficiency" transmission upgrades in the regional transmission expansion plan.

FERC Docket No. EL05-148-000, FERC. Participation in Commission technical sessions regarding the PJM proposed Reliability Pricing Model.

FERC Docket No. EL05-148-000, FERC. Comments filed on behalf of six PJM market participants concerning the proposed rules for participation in the PJM Reliability Pricing Model Installed Capacity market, and related rules for opting out of the RPM market.

FERC Docket No. ER06-407-000. Testimony on behalf of GSG, regarding interconnection issues for new wind generation facilities within PJM.

2005

FERC Docket No. EL05-121-000, Testimony on behalf of several PJM Transmission Owners (Responsible Pricing Alliance) regarding alternative regional rate designs for transmission service and associated market design issues.

FERC Technical Conference of June 16, 2005. (Docket Nos. PL05-7-000, EL03-236-000, ER04-539-000). Invited participant. Statement regarding the operation of the PJM Capacity market and the proposed new Reliability Pricing Model Market design.

American Arbitration Association Nos. 16-198-00206-03 16-198-002070.On behalf of PG&E Energy Trading. Analyses related to the operation and interpretation of power purchase and sale/tolling agreements and electrical interconnection requirements.

Arbitration on behalf of Black Hills Power, Inc. Expert testimony related to a power purchase and sale and energy exchange agreement, as well as FERC criteria related to the applicable code and standards of conduct.

2004

Federal Energy Regulatory Commission. Docket No. Docket No. EL03-236-003 Testimony on behalf of Mirant companies relating to PJM proposal for compensation of frequently mitigated generation facilities.

Federal Energy Regulatory Commission. Docket No. ER03-563-030. Testimony on behalf of Calpine Energy Services regarding the development of a locational Installed Capacity market and associated generator service obligations for ISO-NE. Supplemental testimony filed 2005.

Federal Energy Regulatory Commission. Docket No. EL04-135-000. Testimony on behalf on the Unified Plan Supporters regarding implications of using a flow based rate design to allocate embedded costs.

Federal Energy Regulatory Commission. Docket No. ER04-1229-000. Testimony on behalf of EME Companies regarding the allocation and recovery of administrative charges in the NYISO markets.

Federal Energy Regulatory Commission. Dockets No. EL01-19-000, No. EL01-19-001, No. EL02-16-000, EL02-16-000. Testimony on behalf of PSE&G Energy Resources and Trade regarding pricing in the New York Independent System Operator energy markets.

Federal Energy Regulatory Commission. Invited panelist regarding performance based regulation (PBR) and wholesale market design. Comments related to the potential role of PBR in transmission expansion, and its interaction with market mechanisms for new transmission.

Federal Energy Regulatory Commission. Docket No. ER04-539-000 Testimony on behalf of EME Companies regarding proposed market mitigation in the energy and capacity markets of the Northern Illinois Control Area.

Federal Energy Regulatory Commission. Standardization of Generator Interconnection Agreements and Procedures Docket No. RM02-1-001, Order 2003-A, Affidavit on Behalf of PSEG Companies regarding the modifications on rehearing to interconnection crediting procedures.

Federal Energy Regulatory Commission. Dockets ER03-236-000,ER04-364-000,ER04-367-000,ER04-375-000. Testimony on behalf of the EME Companies regarding proposed market mitigation measures in the Northern Illinois Control Area of PJM.

Federal Energy Regulatory Commission. Dockets PL04-2-000, EL03-236-000. Invited panelist, testimony related to local market power and the appropriate levels of compensation for reliability must run resources.

2003

American Arbitration Association. 16 Y 198 00204 03. Report on behalf of Trigen-Cineregy Solutions regarding an energy services agreement related to a cogeneration facility.

Federal Energy Regulatory Commission. Docket No. EL03-236-000. Testimony on behalf of EME Companies regarding the PJM proposed tariff changes addressing mitigation of local market power and the implementation of a related auction process.

Federal Energy Regulatory Commission. Docket No. PA03-12-000. Testimony on behalf of Pepco Holdings Incorporated regarding transmission congestion and related issues in market design in general, and specifically addressing congestion on the Delmarva Peninsula.

Federal Energy Regulatory Commission. Docket Nos. ER03-262-007, Affidavit on behalf of EME Companies regarding the cost benefit analysis of the operation of an expanded PJM including Commonwealth Edison.

Supreme Court of the State of New York, Index No. 601505/01. Report on behalf of Trigen-Syracuse Energy Corporation regarding energy trading and sales agreements and the operation of the New York Independent System Operator.

Federal Energy Regulatory Commission. Docket No. ER03-262-000. Affidavit on behalf of the EME Companies regarding the issues associated with the integration of the Commonwealth Edison Company into PJM.

Federal Energy Regulatory Commission. Docket No. ER03-690-000. Affidavit on behalf of Hydro Quebec US regarding New York ISO market rules at external generator proxy buses when such buses are deemed non-competitive.

Federal Energy Regulatory Commission. Docket RT01-2-006,007. Affidavit on behalf of the PSEG Companies regarding the PJM Regional Transmission Expansion Planning Protocol, and proper incentives and structure for merchant transmission expansion.

Federal Energy Regulatory Commission. Docket No. ER03-406-000. Affidavit on behalf of seven PJM Stakeholders addressing the appropriateness of the proposed new Auction Revenue Rights/Financial Transmission Rights process to be implemented by the PJM ISO.

Federal Energy Regulatory Commission. Docket No. ER01-2998-002. Testimony on behalf of Pacific Gas and Electric Company related to the cause and allocation of transmission congestion charges.

Federal Energy Regulatory Commission. Docket No. RM01-12-000. On behalf of six different companies including both independent generators, integrated utilities and distribution companies comments on the proposed resource adequacy requirements of the Standard Market Design.

United States Bankruptcy Court, Northern District of California, San Francisco Division, Case No. 01-30923 DM. On behalf of Pacific Gas and Electric Dr. Shanker presented testimony addressing issues related to transmission congestion, and the proposed FERC SMD and California MD02 market design proposals.

2002

Arbitration. Testimony on behalf of AES Ironwood regarding the operation of a tolling agreement and its interaction with PJM market rules.

Federal Energy Regulatory Commission. Docket No. RM01-12-000. Dr. Shanker was asked by the three Northeast ISO's to present a summary of his resource adequacy proposal developed in the Joint Capacity Adequacy Group. This was part of the Standard Market Design NOPR process.

Federal Energy Regulatory Commission. Docket No. ER02-456-000. Testimony on behalf of Electric Gen LLC addressing comparability of a contract among affiliates with respect to non-price terms and conditions.

Circuit Court for Baltimore City. Case 24-C-01-000234. Testimony on behalf of Baltimore Refuse Energy Systems Company regarding the appropriate implementation and pricing of a power purchase agreement and related Installed Capacitycredits.

Federal Energy Regulatory Commission. Docket No. RM01-12-000. Comments on the characteristics of capacity adequacy markets and alternative market design systems for implementing capacity adequacy markets.

2001

Federal Energy Regulatory Commission. Docket ER02-456-000. Testimony on behalf of Electric Gen LLC regarding the terms and conditions of a power sales agreement between PG&E and Electric Generating Company LLC.

Delaware Public Service Commission. Docket 01-194. On behalf of Conectiv et al. Testimony relating to the proper calculation of Locational Marginal Prices in the PJM market design, and the function of Fixed Transmission Rights.

Federal Energy Regulatory Commission. Docket No. IN01-7-000 On behalf of Exelon Corporation . Testimony relating to the function of Fixed Transmission Rights, and associated business strategies in the PJM market system.

Federal Energy Regulatory Commission. Docket No. RM01-12-000. Comments on the basic elements of RTO market design and the required market elements.

Federal Energy Regulatory Commission. Docket No. RT01-99-000. On behalf of the One RTO Coalition. Affadavit on the computational feasibility of large scale regional transmission organizations and related issues in the PJM and NYISO market design.

Arbitration. On behalf of Hydro Quebec. Testimony related to the eligibility of power sales to qualify as Installed Capacitywithin the New York Independent system operator.

Virginia State Corporation Commission. Case No. PUE000584. On behalf of the Virginia Independent Power Producers. Testimony related to the proposed restructuring of Dominion Power and its impact on private power contracts.

United States District Court, Northern District of Ohio, Eastern Division, Case: 1:00CV1729. On behalf of Federal Energy Sales, Inc. Testimony related to damages in disputed electric energy trading transactions.

Federal Energy Regulatory Commission. Docket Number ER01-2076-000. Testimony on behalf of Aquila Energy Marketing Corp and Edison Mission Marketing and Trading, Inc. relating to the implementation of an Automated Mitigation Procedure by the New York ISO.

2000

New York Independent System Operator Board. Statement on behalf of Hydro Quebec, U.S. regarding the implications and impacts of the imposition of a price cap on an operating market system.

Federal Energy Regulatory Administration. Docket No. EL00-24-000. Testimony on behalf of Dayton Power and Light Company regarding the proper characterization and computation of regulation and imbalance charges.

American Arbitration Association File 71-198-00309-99. Report on behalf of Orange and Rockland Utilities, Inc. regarding the estimation of damages associated with the termination of a power marketing agreement.

Circuit Court, 15th Judicial Circuit, Palm Beach County, Florida. On behalf of Okeelanta and Osceola Power Limted Partnerships et. al. Analyses related to commercial operation provisions of a power purchase agreement.

1999

Federal Energy Regulatory Commission. Docket No. ER00-1-000. Testimony on behalf of TransEnergie U.S. related to market power associated with merchant transmission facilities. Also related analyses regarding market based tariff design for merchant transmission facilities.

Federal Energy Regulatory Commission. Docket RM99-2-000. Analyses on behalf of Edison Mission Energy relating to the Regional Transmission Organization Notice of Proposed Rulemaking.

Federal Energy Regulatory Commission. Docket No. ER99-3508-000. On behalf of PG&E Energy Trading, analyses associated with the proposed implementation and cutover plan for the New York Independent System Operator.

Federal Energy Regulatory Commission. Docket No. EL99-46-000. Comments on behalf of the Electric Power Supply Association relating to the Capacity Benefit Margin.

New York Public Service Commission, Case 97-F-1563. Testimony on behalf of Athens Generating Company describing the impacts on pricing and transmission of a new generation facility within the New York Power Pool under the new proposed ISO tariff.

JAMS Arbitration Case No. 1220019318 On behalf of Fellows Generation Company. Testimony related to the development of the independent power and qualifying facility industry and related industry practices with respect to transactions between cogeneration facilities and thermal hosts.

Court of Common Pleas, Philadelphia County, Pennsylvania. Analyses on behalf of Chase Manhattan Bank and Grays Ferry Cogeneration Partnership related to power purchase agreements and electric utility restructuring.

1998

Virginia State Corporation Commission. Case No. PUE 980463. Testimony on behalf of Appomattax Cogeneration related to the proper implementation of avoided cost methodology.

Virginia State Corporation Commission. Case No. PUE980462 Testimony on behalf of Virginia Independent Power Producers related to an applicaton for a certificate for new generation facilities.

Federal Energy Regulatory Commission. Analyses related to a number of dockets reflecting amendments to the PJM ISO tariff and Reliability Assurance Agreement.

U.S. District Court, Western Oklahoma. CIV96-1595-L. Testimony related to anti-competitive elements of utility rate design and promotional actions.

Federal Energy Regulatory Commission Dockets No. EL94-45-001 and QF88-84-006. Analyses related to historic measurement of spot prices for as available energy.

Circuit Court, Fourth Judicial Circuit, Duval County, Florida. Analyses related to the proper implementation of a a power purchase agreement and associated calculations of capacity payments. (Testimony 1999)

1997

United States District Court for the Eastern District of Virginia, CA No. 3:97CV 231. Analyses of the business and market behavior of Virginia Power with respect to the implementation of wholesale electric power purchase agreements.

United States District Court, Southern District of Florida, Case No. 96-594-CIV, Analyses related to anti-competitive practices by an electric utility and related contract matters regarding the appropriate calculation of energy payments.

Virginia State Corporation Commission. Case No. PUE960296. Testimony related to the restructuring proposal of Virginia Power and associated stranded cost issues.

Federal Energy Regulatory Commission. Dockets No. ER97-1523-000 and OA97-470-000, Analyses related to the restructuring of the New York Power Pool and the implementation of locational marginal cost pricing.

Federal Energy Regulatory Commission Dockets No. OA97-261-000 and ER97-1082-000 Analyses and testimony related to the restructuring of the PJM Power Pool and the implementation of locational marginal cost pricing.

Missouri Public Service Commission. Case No. ET-97-113. Testimony related to the proper definition and rate design for standby, supplemental and maintenance service for Qualifying facilities.

American Arbitration Association. Case 79 Y 199 00070 95. Testimony and analyses related to the proper conditions necessary for the curtailment of Qualifying Facilities and the associated calculations of negative avoided costs.

Virginia State Corporation Commission. Case Number PUE960117 Testimony related to proper implementation of the differential revenue requirements methodology for the calculation of avoided costs.

New York Public Service Commission. Case 96-E-0897, Analyses related to the restructuring of Consolidated Edison Company of New York and New York Power Pool proposed Independent System Operator and related transmission tariffs.

1996

Florida Public Service Commission. Docket No. 950110-EI. Testimony related to the correct calculation of avoided costs using the Value of Deferral methodology and its implementation.

Federal Energy Regulatory Commission Dockets No. EL94-45-001 and QF88-84-006. Testimony and Analyses related to the estimation of historic market rates for electricity in the Virginia Power service territory.

Circuit Court of the City of Richmond Case No. LA-2266-4. Analyses related to the incurrence of actual and estimated damages associated with the outages of an electric generation facility.

New Hampshire Public Utility Commission, Docket No. DR96-149. Analyses related to the requirements of light loading for the curtailment of Qualifying Facilities, and the compliance of a utility with such requirements.

State of New York Supreme Court, Index No. 94-1125. Testimony related to system planning criteria and their relationship to contract performance specifications for a purchased power facility.

United States District Court for the Western District of Pennsylvania, Civil Action No. 95-0658. Analyses related to anti-competitive actions of an electric utility with respect to a power purchase agreement.

United States District Court for the Northern District of Alabama, Southern Division. Civil Action Number CV-96-PT 0097-S. Affadavit on behalf of TVA and LG&E Power regarding displacement in wholesale power transactions.

1995

American Arbitration Association. Arbitration No. 14 198 012795 H/K. Report concerning the correct measurement of savings resulting from a commercial building cogeneration system and associated contract compensation issues.

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