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 |

**DIRECT TESTIMONY OF KEVIN M. MURRAY**

**ON BEHALF OF INDUSTRIAL ENERGY USERS-OHIO**

Samuel C. Randazzo (Counsel of Record)

Frank P. Darr

Joseph E. Oliker

McNees Wallace & Nurick LLC

21 East State Street, 17th Floor

Columbus, OH 43215-4228

Telephone: (614) 469-8000

Telecopier: (614) 469-4653

sam@mwncmh.com

fdarr@mwncmh.com

joliker@mwncmh.com

**April 4, 2012** **Attorneys for Industrial Energy Users-Ohio**

**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 |

**DIRECT TESTIMONY OF KEVIN M. MURRAY**

**ON BEHALF OF INDUSTRIAL ENERGY USERS-OHIO**

INDEX

Page No.

I. INTRODUCTION 1

II. APPROPRIATE CHARGES FOR CAPACITY 13

III. DEMAND CURVE OPERATION 32

IV. CAPACITY BILLING 33

v. CONCLUSION 34

CERTIFICATE OF SERVICE

EXHIBITS

**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 |

**DIRECT TESTIMONY OF KEVIN M. MURRAY**

**ON BEHALF OF INDUSTRIAL ENERGY USERS-OHIO**

**I. INTRODUCTION**

**Q1. Please state your name and business address.**

A1. My name is Kevin M. Murray. My business address is 21 East State Street, 17th Floor, Columbus, Ohio 43215-4228.

**Q2. By whom are you employed and in what position?**

A2. I am a Technical Specialist for McNees Wallace & Nurick LLC (“McNees”) and the Executive Director of the Industrial Energy Users-Ohio (“IEU-Ohio”). I am providing testimony on behalf of IEU-Ohio.

**Q3. Please describe your educational background.**

A3. I graduated from the University of Cincinnati in 1982 with a Bachelor of Science degree in Metallurgical Engineering.

**Q4. Please describe your professional experience.**

A4. I have been employed by McNees for 14 years where I focus on helping   
IEU-Ohio members address issues that affect the price and availability of utility services. I have also been actively involved, on behalf of commercial and industrial customers, in the formation of regional transmission operators (“RTOs”) and the organization of regional electricity markets from both the supply-side and demand-side perspective. I serve as an end-use customer sector representative on the Midwest Independent Transmission System Operator, Inc. (“Midwest ISO” or “MISO”) Advisory Committee and I have been actively involved in MISO working groups that focus on various issues since 1999. Prior to joining McNees, I was employed by the law firm of Kegler, Brown, Hill & Ritter (“KBH&R”) in a similar capacity. Prior to joining KBH&R, I spent 12 years with The Timken Company, a specialty steel and roller bearing manufacturer. While at The Timken Company, I worked within a group that focused on meeting the electricity and natural gas requirements for facilities in the United States. I also spent several years in supervisory positions within The Timken Company’s steelmaking operations.

**Q5. Have you previously testified before the Public Utilities Commission of Ohio (“Commission”)?**

A5. Yes. The proceedings before the Commission in which I have submitted expert testimony are identified in Exhibit KMM-1.

**Q6. What is the purpose of your testimony?**

A6. The purpose of my testimony is to address whether it would be appropriate to establish a cost-based charge for capacity to be paid by competitive retail electric service (“CRES”) providers that acquire retail customers that receive distribution service from Ohio Power Company (“OP”) and Columbus Southern Power Company (“CSP”), now both merged as Ohio Power Company and doing business as AEP-Ohio. For the reasons discussed in my testimony, based upon both policy and legal considerations, the Commission should not approve AEP-Ohio’s request to charge a cost-based rate for capacity. I also address an incorrect characterization of how the downward sloping demand curve operates in PJM Interconnection LLC’s (“PJM”) Reliability Pricing Model (“RPM”) contained within the testimony of Dana E. Horton. Finally, I describe the type of information I recommend the Commission require AEP-Ohio to provide so that it is possible for consumers and CRES providers to identify if the capacity charge billing determinants are correct. These billing determinants are necessary to verify the accuracy of the amount of any capacity charge bill that a customer or CRES provider may incur regardless of the level of the capacity charge.

**Q7. How do the issues raised by AEP-Ohio in this proceeding relate to efforts to develop competitive markets for electricity?**

A7. The significance of the issues raised by AEP-Ohio’s application in this proceeding can be better understood by looking more broadly at what has happened at the state and federal level to restructure the electric industry to address the anticompetitive structure of the industry and to allow competitive markets to serve the public interest in reasonable rates and reliable service. This broader history includes background information on determinations that have been made by the Federal Energy Regulatory Commission (“FERC”).

FERC has increasingly relied upon competitive market forces to establish “just and reasonable” prices at the wholesale level in both the gas and electric sectors. As part of FERC’s effort to remedy the anticompetitive electric industry structure which was dominated by vertically integrated investor-owned electric utilities, FERC required electric utilities to move to open access, comparable and non-discriminatory transmission service and encouraged vertically integrated electric utilities that owned generating plants to transfer operational control of their high voltage transmission facilities to independent RTOs such as PJM. When Ohio enacted its electric restructuring legislation in 1999, the legislation similarly included a requirement that owners of transmission facilities transfer control of such facilities to an RTO.[[1]](#footnote-1) Again, FERC’s directives and policy announcements were part of FERC’s effort to remedy undue discrimination in the operation of transmission facilities that occurred because vertically integrated utilities used their operation and control of their transmission facilities to favor their generation assets.

Over time, the role of RTOs has expanded, subject to FERC’s supervision and regulation, beyond the operation and control of transmission assets to remedy the anticompetitive industry structure. Today, RTOs are responsible for maintaining real time reliability of the electric grid and do so in coordination with regional electricity markets. Under FERC’s supervision, they have managed the operation of regional electricity markets with independent market-monitoring oversight to determine if and when RTO or FERC intervention is needed to address anticompetitive behavior or circumstances where competition is not adequate to produce just and reasonable rates. For example, PJM began operating a regional electricity market in 1997. Currently, PJM coordinates the movement of wholesale electricity in all or parts of thirteen states and the District of Columbia.

These regional electricity markets typically include a number of products associated with the generation of electricity. Within PJM, its market structure includes separate products for capacity and energy as well as various ancillary services.

The development and operation of regional electricity markets has also evolved over time with corresponding changes in the market rules established by the RTOs. Various stakeholders affected by changes in market rules often disagree as to whether market rule changes are appropriate, with FERC acting as the arbiter when disagreements arise. The capacity market rules in PJM have been a source of significant and frequent stakeholder disagreement.

**Q8. Why does PJM operate a capacity market?**

A8. PJM’s capacity market is intended to ensure the adequate availability of necessary resources that can be called upon to ensure the reliability of the grid. In PJM, the capacity market structure provides transparent information to enable forward capacity market signals to support infrastructure investment. The capacity market design provides a forward mechanism to evaluate the ongoing reliability requirements in a transparent way to provide opportunity for generation, demand response, energy efficiency, and transmission solutions.

Within the PJM region, the basis for the capacity market design is RPM. The goal of RPM is to align capacity pricing with system reliability requirements and to provide transparent information to all market participants far enough in advance for actionable response to the information. In RPM, the fundamental elements to achieve this are:

* Locational capacity pricing to recognize and quantify the locational value of capacity;
* A variable resource requirement mechanism to adjust price based on the level of resources procured;
* Forward commitment of supply by generation, demand resources and qualified transmission upgrades cleared in a multi-auction structure; and
* A reliability backstop mechanism to ensure that sufficient generation, transmission and demand response solutions will be available to preserve system reliability.

**Q9. Is one of the functions of RPM providing forward prices for capacity?**

A9. Yes. RPM is intended to provide a forward price signal for capacity resources and load serving entity (“LSE”) obligations that also reflects PJM’s regional transmission expansion planning process. RPM can also have a locational nature to the pricing signal. RPM relies upon a multi-auction structure designed to procure resource commitments to satisfy the region’s unforced capacity obligation through a base residual auction (“BRA”), incremental auctions and bilateral market transactions.

**Q10. How does RPM operate?**

A10. BRAs are held each May three years in advance of a delivery year, which runs from June 1 through the following May 31. Subsequent to the BRA, up to three incremental auctions are held to procure additional resources, if necessary, and to adjust commitments to reflect known changes in market requirements prior to the delivery year. The auction results produce locational capacity charges that are allocated among LSEs through a locational reliability charge.

For each delivery year, PJM determines a peak load forecast. PJM then calculates an installed reserve margin for the PJM region. The installed reserve margin is defined to be the level of installed reserves in excess of the forecast peak load needed to maintain the desired reliability index of ten years, on average, per occurrence (loss of load expectation of one occurrence every ten years) after emergency procedures to invoke load management. The installed reserve margin is calculated based upon probabilistic studies. PJM then calculates the forecast pool requirement which represents the quantity of unforced capacity resources needed recognizing the pool-wide equivalent average forced outage rate and the expected performance of demand response resources.

Prior to conducting BRAs, PJM assesses the need to create locational deliverability areas (“LDAs”). LDAs are load pockets in which transmission import capacity is constrained, therefore requiring the use of internal capacity resources within the LDAs to satisfy the reliability objective. The areas within PJM that are not LDAs are referred to as the balance of the RTO zone. Depending on supply and demand conditions, price separation may occur for LDAs from the balance of the RTO zone when the BRA is conducted.

The BRA is structured to obtain sufficient capacity resources to satisfy the forecast pool requirement scaled to reflect normal weather. The BRA relies upon a downward sloping demand curve called the variable resource requirement curve. The use of the variable resource requirement curve may result in the procurement of capacity resources in excess of the reliability objective if the total cost of resource procurement for the LDAs or balance of the RTO zone is lower at the higher level of reliability than it would be at the target reliability objective. After the BRA and prior to the delivery year, PJM conducts three incremental auctions. The incremental auctions are conducted to allow for replacement resource procurement and increases and decreases in the reliability objective resulting from, for example, a change in load forecast. The results from all of the auctions are mathematically weighted to determine a final zonal capacity price.

Once all auctions have been concluded, the final zonal capacity obligation is determined. This is done through the use of a final zonal scaling factor that is used to determine an LSE’s daily unforced capacity obligation.

**Q11. How are capacity charges billed under RPM?**

A11. For settlement purposes, each PJM electric distribution company (“EDC”) is responsible for allocating its normalized previous summer’s peak to each customer in the zone (both wholesale and retail). According to PJM’s business practice manuals, the process used by an EDC to allocate peak load contributions to its customers is supposed to be based upon rules negotiated with the EDC’s regulators. To assist in performing these allocations, PJM publishes information known as the five coincident peaks or 5CP for each summer, typically by mid-October. The 5CP reflects the five highest non-holiday weekday RTO unrestricted daily peaks from the summer. An individual customer’s usage during those five hours is known as the peak load contribution or PLC.

**Q12. Do LSEs have options other than participation in the periodic capacity auctions conducted by PJM?**

A12. Yes. PJM’s capacity market also allows an alternative method of participation, known as the Fixed Resource Requirement (“FRR”) alternative. FRR permits an LSE the option to submit an FRR capacity plan (to be reviewed and approved by PJM) and meet a fixed capacity resource requirement as an alternative to the requirement to participate in RPM auctions, which feature a variable capacity resource requirement. AEP-Ohio is an FRR entity.

**Q13. How was PJM’s capacity market created?**

A13. RPM and the FRR option are byproducts of a FERC-approved settlement negotiated by many parties in a case in which PJM proposed changes to its market rules. That settlement, which was signed by American Electric Power Service Corporation (“AEPSC”), on behalf of all the AEP operating companies in PJM, was accepted by FERC on December 22, 2006. *PJM Interconnection, L.L.C.,* 117 FERC ¶ 61,331 (2006).

**Q14. Has AEP-Ohio supported RPM as reasonable?**

A14. Yes. AEP-Ohio operated pursuant to the RPM rules for a number of years without objection. Indeed, AEP-Ohio strongly defended the PJM market rules and RPM in proceedings before this Commission. For example, in 2007, AEP-Ohio argued that Ohio was part of a robust regional energy market and urged the Commission to move forward with a competitive bidding process for the provision of SSO generation service:

The competitive significance of RTOs is well recognized. In *New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities*, Docket No. RM06-10-000, FERC Statutes and Regulations ¶31,233 (October 20, 2006) (“*Order 688*”), the FERC found that both MISO and PJM are independently administered, auction-based day-ahead and real-time wholesale markets for the sale of electric energy. The FERC also found that the existence of wholesale markets for long-term sales of capacity and electric energy is satisfied by the existence of long-term bilateral contracts for sales of capacity and energy and is a sufficient indication of a market. *Order 688* ¶117.

The PJM energy market provides substantial benefits to the region based on its ability for utilities and customers to access a larger number of generation resources to fulfill load requirements while utilizing a robust transmission system. PJM's methodology results in the least cost generating units serving the load requirements, subject to any transmission constraints. This method is similar to the one performed by AEP for its system prior to joining PJM. PJM, however, provides access to additional generating units and the capability of importing generation from MISO without paying additional transmission rates. The resulting dispatch price provides transparent economic signals that guide short- and long-run decisions by participants and regulators.

Case No 07-796-EL-ATA, *et al.*, *Reply Comments of Columbus Southern Power Company and Ohio Power Company* at 4-5 (October 12, 2007). In fact, in its initial comments in that proceeding, AEP-Ohio indicated that if a competitive bidding process were held to obtain SSO generation for AEP-Ohio’s load, given AEP-Ohio’s FRR status, AEP-Ohio would sell capacity to winning bidders at the RPM clearing price until such time as AEP-Ohio could terminate its FRR status. Case No 07-796-EL-ATA, *et al.*, *Comments of Columbus Southern Power Company and Ohio Power Company* at 5 (September 5, 2007).

**Q15. Has AEP-Ohio modified its opinion on the reasonableness of RPM?**

A15. Yes. On November 1, 2010, AEPSC, on behalf of OP and CSP, submitted an application with FERC in Docket No. ER11-1995-000 and subsequently re-submitted an application in Docket No. ER11-2183-000 seeking to establish what AEPSC characterized as a cost-based charge for capacity supplied to CRES providers that provide competitive generation service to retail load within the AEP-Ohio service area. In its FERC application, AEPSC asserted that its sudden proposal to change the basis for establishing prices for capacity is consistent with Section D.8 of Schedule 8.1 of the PJM Reliability Assurance Agreement (“RAA”) which AEP-Ohio signed when it became a transmission-owner member of PJM. Section D.8 of the RAA provides, in relevant part:

In a state regulatory jurisdiction that has implemented retail choice, the FRR Entity must include in its FRR Capacity Plan all load, including expected load growth, in the FRR Service Area, notwithstanding the loss of any such load to or among alternative retail LSEs. 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, and a retail LSE may at any time exercise its rights under Section 206 of the FPA.[[2]](#footnote-2)

On December 8, 2010, the Commission issued an entry in this proceeding confirming capacity supplied to CRES providers serving customers in the AEP-Ohio service area would be priced based upon prevailing RPM market prices, the status quo at that time. The entry directed interested parties to file comments on an appropriate state compensation mechanism. The Commission subsequently established a procedural schedule for an evidentiary hearing commencing on October 4, 2011.

**Q16. What occurred after the Commission established a schedule for an evidentiary hearing commencing on October 4, 2011?**

A16. On September 7, 2011, a strongly contested stipulation and recommendation (“Stipulation”) was submitted in this case and a number of other AEP-Ohio related proceedings. The Stipulation provided for a two-tiered structure to price capacity for CRES providers, with some capacity priced at prevailing market prices and any remaining capacity priced at $255 per megawatt-day (“MW-day”). The Commission adopted the Stipulation with modifications on December 14, 2011.

However, in response to applications for rehearing, the Commission subsequently granted the rehearing requests on the December 14, 2011 Order and then rejected the Stipulation on February 23, 2012 finding that it was not consistent with the public interest. The Commission’s rejection of the Stipulation resulted in capacity prices for CRES providers serving customers in AEP-Ohio’s service area reverting to the state compensation mechanism (i.e., RPM-based prices). Subsequently, the Commission granted a motion by AEP-Ohio in this proceeding to re-establish, on an interim basis, a two-tiered pricing structure for capacity, but only through May 31, 2012, with capacity prices thereafter reverting to RPM-based prices. The re-established two-tiered capacity charge retained opportunities for RPM-based pricing to remain in cases where CRES providers served customers (including “mercantile customers”) through eligible community aggregation programs.

**II. APPROPRIATE CHARGES FOR CAPACITY**

**Q17. Do you believe that AEP-Ohio’s application in this proceeding to establish a so-called cost-based price for capacity utilized by CRES providers to serve retail load within the AEP-Ohio service area is reasonable?**

A17. No. There are multiple reasons why approval of AEP-Ohio’s application in this proceeding would result in unreasonable if not unlawful outcomes and, more broadly speaking, go against the structural reforms and policy objectives that are part and parcel of the effort to remedy an anticompetitive electric industry structure.

First, establishing a cost-based rate for capacity would be contrary to the state’s policies and would uniquely provide an unwarranted subsidy to AEP-Ohio, to the detriment of its competitors and shopping and non-shopping customers alike.

Second, charging CRES providers the proposed cost-based rate for capacity would not result in the generation capacity service and price applied to CRES providers being comparable to the charge for capacity embedded in the default generation supply price embedded in the standard service offer (“SSO”). I would also note that in prior Commission proceedings involving the establishment of default generation supply prices for AEP-Ohio, AEP-Ohio has successfully asserted that the establishment of such prices has nothing to do with cost-based ratemaking. For example, in its first electric security plan (“ESP”) AEP-Ohio proposed automatic annual increases in the non-fuel base generation rates and argued such increases did not have to be based upon actual costs:

Section II. B. of the Companies' Application makes clear that there are two parts to their proposal to increase non-FAC generation rates. (Application, p. 5). First, the Companies propose increases related to carrying charges which will be incurred in 2009-2011 on a portion of environmental investments made during 2001-2008. Those increases, which are related to specific, calculated carrying charges, are not part of the support for the second part of the non-FAC generation rate increase, i.e. the 2009-2011, 3 percent and 7 percent automatic annual non-FAC generation rate increases. This second part includes as part of its support carrying charges on environmental investments to be made during the 2009-2011 ESP period. This second part is not cost-based and that is the focus of the opposition to the annual 3 percent and 7 percent increases.

Case No. 08-917-EL-SSO, *et al.*, *Columbus Southern Power Company’s and Ohio Power Company’s Reply Brief* at 47 (January 14, 2009) (emphasis added) (footnotes omitted).

During the period when electric prices were very volatile and at times high as a result of things like the Enron fiasco, the lack of maturity in the electric market, natural gas supply constraints, and high natural gas prices influenced, at times, by improper market manipulation, AEP-Ohio used the increases in market-based electric prices to significantly and repeatedly push for higher default generation supply prices. It may be a coincidence, but AEP-Ohio’s desire to obtain a cost-based capacity price comes at a time when the same market-pricing mechanisms that AEP-Ohio previously relied upon to support rate increases suggest that its current default generation supply prices are excessive. It also appears that the proposed CRES capacity price is designed to allow AEP-Ohio to capture most of the bill reduction benefits that consumers would see by switching to a competitive supplier, including the affiliated CRES provider AEP-Retail Energy.

Third, as IEU-Ohio witness J. Edward Hess explains in his testimony, AEP-Ohio’s application in this proceeding is really a belated, and as I understand it based on the advice of counsel, illegal request to obtain “transition revenue” well after the opportunity to submit such a claim expired. I also understand that this “transition revenue” claim was submitted by AEP-Ohio long after it surrendered its right to submit such a claim and to impose a transition charge on shopping customers. Finally, as discussed later in my testimony, based upon discussions with counsel, it is my understanding that the Commission no longer has the authority to subject generation service to cost-based regulation regardless of the form of the cost-based ratemaking methodology.

**Q18. Is the proposed cost-based rate for capacity a request for additional transition revenues?**

A18. Yes. It may be helpful to provide some additional context to help explain my answer.

Ohio made the move to “customer choice” in 1999 with the passage of Amended Substitute Senate Bill 3 (“SB3”). At the time, there were parallel federal efforts to restructure the wholesale electric market and address the anticompetitive electric industry structure. These initiatives were rooted in the view that competitive markets could do a better job of advancing the public interest in reasonable prices, reliable service and innovation than traditional regulation.

SB3 contained policy objectives and established the process by which the evolution to reliance upon competitive markets would occur for competitive services such as generation supply. The process included the unbundling or separation of the three major functions (generation or production, transmission and distribution) associated with retail electric service into separate competitive and non-competitive service components with separate prices for such unbundled components.

SB3 established a “transition period” beginning on January 1, 2001 and ending on December 31, 2010. Within the transition period, SB3 created a five-year market development period (“MDP”) during which incumbent investor-owned utilities and customers had the opportunity to prepare for and transition to a competitive market. SB3 directed the Commission to structure transition plans with the objective of obtaining at least 20% customer switching by the mid-point of the MDP which could end no later than December 31, 2005.

The evolutionary approach to restructuring the retail investor-owned electric industry in Ohio, accompanied by the completion of the transitional tasks, served two important objectives. The first objective was to provide customers with certain price protections from the dysfunction that is often associated with new and immature markets until such time as the retail market was mature enough to produce “reasonable” prices. The General Assembly protected customers by specifying that the total price of electricity in effect in October 1999 would define the total price envelope within which the individual or unbundled generation, transmission and distribution prices would be established through the transition plan process.[[3]](#footnote-3) SB3 also provided residential customers an immediate benefit in the form of a 5% discount.

The second consequence of the SB3 structure protected incumbent electric distribution utilities (“EDUs”) during the MDP (and the balance of the transition period) from potential revenue loss that might otherwise be caused by an abrupt exposure to a new and immature market. In 2001, price offers for competitive retail service were relatively low and the transition structure protected EDUs from revenue and earnings erosion. Each EDU was also provided an opportunity to protect itself in the event the EDU judged its unbundled generation rates to be in excess or above the generation service prices that would result from the forces of effective competition. The right to pursue this protection required an EDU to file a claim with the Commission for “transition revenue” (i.e., the positive difference between existing unbundled generation prices and the unbundled prices attributed by the utility to effective competition—sometimes called “stranded costs”) as part of the electric transition plan (“ETP”) filings. All transition costs were required to be collected by December 31, 2010. OP’s and CSP’s ETP cases were ultimately resolved through stipulations approved by the Commission. In the stipulations, OP and CSP agreed to forego claims for recovery of above-market generation costs (generation transition costs or “GTC”). *In the Matter of the Applications of Columbus Southern Power Company and Ohio Power Company for Approval of Their Electric Transition Plans and for Receipt of Transition Revenues*, Case Nos. 99-1729-EL-ETP and 99-1730-EL-ETP, Opinion and Order at 16 (September 28, 2000). IEU-Ohio witness Hess also discusses this history.

Shortly after the Stipulation was filed on September 7, 2011 in Case Nos. 11-346-EL-SSO, *et al.*, AEP-Ohio issued a press release that described the effect of the settlement as follows:

After a decade of legislative and regulatory changes to Ohio’s market for electricity, this agreement allows an appropriate transition to a fully competitive electricity generation environment for AEP in the state.[[4]](#footnote-4)

AEP-Ohio has continued to maintain that it is seeking an additional transition period in this case as well. After the Stipulation was rejected by the Commission on February 23, 2012, AEP-Ohio filed a motion seeking to re-impose the two-tiered capacity pricing scheme contained in the Stipulation. In the motion, AEP-Ohio asserted that it was seeking an additional “transition period” until it could establish even higher formula-based rates.[[5]](#footnote-5) So, in addition to the transition provided by SB3, this proceeding, according to AEP-Ohio, is designed to provide more time for AEP-Ohio to transition to a fully competitive retail electric generation market. During this additional transition that I understand has no basis in law, if the Commission approves AEP-Ohio’s application, customers will be economically blocked from obtaining competitive retail electric services (such as generation supply) from CRES providers, thereby allowing AEP-Ohio to collect, largely on a non-bypassable basis, the revenues produced by its SSO rates.

**Q19. Are there differences between the transition in SB3 and the second transition proposed by AEP-Ohio?**

A19. Yes. Broadly speaking, the SB3 transition provided customers with electric bill predictability and certainty while giving customers the opportunity to do better by shopping. Residential customers were given a 5% discount off of the unbundled generation price. The fuel adjustment clause (“FAC”) was eliminated. SB3’s transition did not shift revenue responsibility within or between rate groups.

In contrast, the transition resulting from AEP-Ohio’s formula-based capacity rates will limit shopping. So, the transition clearly protects AEP-Ohio but it does not contain the balanced, pro “customer choice” transition that was created in SB3.

**Q20. How would a cost-based price for capacity subsidize generation service for AEP-Ohio?**

A20. It would allow AEP-Ohio to impose and collect revenues from a currently higher than market charge on competitors who seek to serve load in the AEP-Ohio service area, when various AEP affiliates are actively acquiring load at both the wholesale and retail level in other electric utility service areas while relying upon market-based priced capacity in order to do so. This is fundamentally unfair -- to customers throughout Ohio, the broader PJM region and to CRES providers.

**Q21. Have AEP-Ohio affiliates participated in recent auctions to acquire generation to serve SSO load in Ohio?**

A21. Yes, several times, including on two recent occasions. Most recently, AEP-Ohio affiliates participated in an auction held December 14, 2011 to acquire SSO generation supply for Duke Energy Ohio (“Duke”) customers and in a January 24, 2012 auction to acquire SSO generation supply for customers of FirstEnergy’s EDUs, which are The Cleveland Electric Illuminating Company, the Ohio Edison Company and The Toledo Edison Company. Both auctions required bidders to supply energy, capacity, losses and ancillary services necessary to provide SSO generation supply.

**Q22. What were the results of those auctions?**

A22. The December 14, 2011 auction produced a clearing price of $49.72 per megawatt-hour (“MWh”) for the January 1, 2012 to May 31, 2013 delivery year, $51.10 per MWh for the January 1, 2012 to May 31, 2014 delivery year, and $57.08 per MWh for the January 1, 2012 to May 31, 2015 delivery year. A summary of the auction results is included as Exhibit KMM-2. The January 24, 2012 auction produced a clearing price of $44.76 per MWh for the June 1, 2012 to May 31, 2014 delivery year.

**Q23. Did AEP-Ohio affiliates participate in these auctions?**

A23. Yes. As shown on Exhibit KMM-2, in the December 14, 2011 auction, AEP Energy Partners, Inc. won a total of 5 tranches and AEPSC won 6 tranches. As shown on Exhibit KMM-3, in the January 24, 2012 auction, AEP Energy Partners, Inc. won 2 tranches and AEPSC won 2 tranches.

**Q24. How do bidders in the Duke and FirstEnergy SSO auctions acquire and pay for capacity and reflect those costs in their bids?**

A24. Both FirstEnergy and Duke are presently FRR entities in PJM. As a result, bidders were required to obtain and pay for capacity from the FirstEnergy operating companies or Duke for their respective auctions.

The FirstEnergy EDUs do not own any electric generation so their FRR election was executed differently than how AEP-Ohio participates in FRR. When FirstEnergy made the commitment to join PJM, the BRAs for the 2011-2012 and 2012-2013 delivery years had already occurred. Thus, it was necessary to establish a transition mechanism for FirstEnergy.

The transition plan developed for FirstEnergy established a two-year FRR to allow FirstEnergy to synchronize with PJM’s normal RPM cycle. FirstEnergy’s transition plan to enter PJM required it to obtain the necessary capacity resources for the 2011-2012 and 2012-2013 delivery years and include those capacity resources in an FRR plan submitted to PJM prior to each delivery year. The transition plan provided that FirstEnergy would participate in the BRA for the 2013-2014 delivery year. The BRA for the 2013-2014 delivery year (“RTO locational deliverability area” or “RTO LDA”) cleared at a price of $27.73 per MW-day.

Because FirstEnergy’s Ohio EDUs do not own generating assets, two integration auctions were conducted to obtain capacity resources for the 2011-2012 and 2012-2013 delivery years. The 2011-2012 FRR integration auction cleared 12,583.2 MW of unforced capacity in the RTO at a resource clearing price of $108.89 per MW-day. The 2012-2013 FRR integration auction cleared 13,038.7 MW of unforced capacity in the RTO at a resource clearing price of $20.46 per MW-day. These capacity prices are very close to capacity prices from the larger BRA for the same delivery years. Bidders in the auctions to obtain SSO generation supply for FirstEnergy were required to rely upon capacity secured in the two integration auctions and reflect this in their offer prices for the 2011-2012 and 2012-2013 delivery years. For the 2013-2014 delivery year, bidders in the auctions to obtain SSO generation supply for FirstEnergy will use capacity secured through PJM’s capacity auctions. Thus, the clearing price of $44.76 per MWh in the January 24, 2012 auction reflects bidders paying the FirstEnergy EDUs $20.46 per MW-day for capacity in the 2012-2013 delivery year, and paying the BRA clearing price for capacity of $27.73 per MW-day for the 2013-2014 delivery year.

Duke also is operating under an FRR election but, similar to AEP-Ohio, it owns generating assets. Duke designated the capacity resources held to serve SSO load under its FRR plan submitted to PJM. Bidders participating in the Duke SSO auctions acquire capacity and pay Duke at prevailing market prices for capacity, the final clearing price established under RPM. The bid prices from the December 14, 2011 auction reflect BRA capacity costs of $110.00 per MW-day for the 2011-2012 delivery year, $16.46 per MW-day for the 2012-2013 delivery year, $27.73 per MW-day for 2013-2014 delivery year, and $125.99 per MW-day for the 2014-2015 delivery year. Thus, when AEP-Ohio affiliates compete at the wholesale level to serve customers in other areas of Ohio, they rely upon capacity priced at prevailing market prices, or RPM.

**Q25. Are AEP-Ohio affiliates competing to serve retail customers throughout Ohio?**

A25. Yes. AEP Retail Energy, a non-regulated affiliate, is currently offering to serve customers throughout Ohio in regions open to retail customer choice. I have included, as Exhibit KMM-4, supply offers and the associated terms and conditions for residential customers as of March 15, 2012. AEP Retail Energy is also offering to supply commercial and industrial customers.

**Q26. When AEP Retail Energy acquires retail load, how do PJM’s rules require AEP Retail Energy to obtain and pay for capacity?**

A26. The answer varies slightly depending on service areas due to FRR status and prior decisions of this Commission. For customers provided distribution service by the FirstEnergy EDUs or Duke, the process is very similar to how capacity is supplied to bidders in the SSO auction. As CRES providers acquire load in these service areas, they compensate the FRR entity for capacity at the same prices discussed earlier in my testimony that were relied upon by SSO bidders.

Dayton Power and Light (“DP&L”) is not operating under an FRR plan. For EDUs in retail access states not under an FRR plan, CRES providers acquire and/or release capacity as they gain or lose load and pay for capacity at prevailing market prices - RPM. Thus, other than in AEP-Ohio’s service area, when its affiliate AEP Retail Energy competes to serve customers, it obtains and pays for capacity based upon market-based rates, or RPM, and other generation suppliers receive market-based, rather than some form of cost-based compensation for capacity.

When AEP Retail Energy serves customers in AEP-Ohio’s service territory, the price for capacity will differ on an interim basis under the two-tiered pricing structure for capacity discussed earlier in my testimony. The price for capacity will be either market-based or $255 per MW-day, based upon the Commission’s March 7, 2012 entry in this proceeding.

It is fundamentally unfair and contrary to Ohio’s pro-competition policies to allow AEP-Ohio’s affiliates to serve non AEP-Ohio EDU customers in other areas of Ohio while paying market-based prices for capacity, but require CRES providers attempting to serve AEP-Ohio EDU customers to pay cost-based rates for capacity. The cost-based rate for capacity also amounts to a subsidy to AEP-Ohio’s supposedly corporately separated generation business as it is significantly higher than prevailing market prices.

**Q27. Are there other indicators that RPM clearing prices are representative of prevailing market prices for capacity?**

A27. Yes. As previously mentioned, FirstEnergy’s integration into PJM involved a transition plan to synchronize with the regular schedule developed to establish prices through the RPM mechanism. These capacity clearing prices from the FirstEnergy transitional auctions are very similar to the prevailing capacity prices in the BRA for the unconstrained region of PJM for the same delivery year, which were $110.00 per MW-day for the 2011-2012 delivery year and $16.46 per MW-day for the 2012-2013 delivery year. AEP-Ohio provides service within this unconstrained PJM region. Thus, the transitional FRR integration auctions conducted for FirstEnergy are representative of the broader relevant market conditions and pricing outcomes in the unconstrained region of PJM, which includes AEP-Ohio. [BEGIN CONFIDENTIAL TESTIMONY]

[END CONFIDENTIAL TESTIMONY].

**Q28. Has American Electric Power, through its other operating companies, recognized RPM prices as an appropriate market-based rate for capacity in other jurisdictions?**

A28. Yes, in addition to my earlier discussion of AEP-Ohio’s use of and reliance upon PJM’s RPM to support its pricing proposals and policy advocacy here in Ohio, it is also relying on RPM in several adjoining or nearby states to identify appropriate capacity compensation. A number of American Electric Power EDUs in other states in the PJM region offer retail customers experimental rates or rates under pilot programs that reflect PJM real-time prices. For example, Kentucky Power offers customers an experimental real-time pricing rate, Tariff R.T.P., a copy of which is attached to my testimony as Exhibit KMM-6. Under this Kentucky Power rate schedule, the price charged to customers includes a component for capacity. The price reflected for capacity in the rates charged to Kentucky Power customers is based upon the prevailing RPM prices.

Indiana Michigan Power (“I&M”) offers a similar experimental real-time pricing, Tariff R.T.P. in both its Indiana and Michigan rate zones. I have attached a copy of I&M’s Tariff R.T.P. for the Indiana rate zone to my testimony as Exhibit KMM-7 and a copy of the I&M Tariff R.T.P. for the Michigan rate zone to my testimony as Exhibit KMM-8. In both instances, the capacity component of the rate charged to I&M customers is based upon the prevailing RPM prices.

Appalachian Power Company offers its customers in Virginia two dynamic pricing pilot rates, Schedule DP-1 and Schedule DP-2, which are attached to my testimony as Exhibit KMM-9. Schedule DP-1 allows eligible customers to have usage for the generation component of their bills charged based upon prices established in PJM’s market. The capacity component of the rate is based on prevailing RPM prices.

Schedule DP-2 is perhaps more interesting in that it allows customers with eligible qualifying facilities to sell electricity energy and capacity to Appalachian Power Company, with the rates based upon PJM’s market. In other words, when Appalachian Power Company is purchasing capacity, the appropriate price is based upon prevailing RPM prices.

Thus, even in other states like Michigan that have adopted some form of “customer choice”, or states that continue to rely upon rate base, rate of return economic regulation to establish retail electric prices, the AEP operating companies are using PJM’s RPM to establish capacity related prices.

**Q29. What is your understanding of the Commission’s authority to approve a cost-based charge for capacity as requested by AEP-Ohio?**

A29. Based upon discussions with counsel, it is my understanding that with the enactment of SB3 in 1999, the Ohio legislature modified the law such that electric generation service is no longer subject to traditional Commission economic regulation except as otherwise provided in Chapter 4928, Ohio Revised Code. The Commission has affirmed this several times, most recently in its order denying OP’s request for approval to recover shutdown costs associated with Unit 5 of the Sporn Generating Station. *In the Matter of the Application of Ohio Power Company for Approval of the Shutdown of Unit 5 of the Philip Sporn Generating Station and to Establish a Plant Shutdown Rider,* Case No. 10-1454-EL-RDR, Finding and Order at 16 (January 11, 2012).

**Q30. Is AEP-Ohio’s proposed cost-based charge comparable to the charge for capacity embedded in the default generation supply SSO prices?**

A30. No. As acknowledged by AEP-Ohio witness Richard E. Munczinski on page 10 of his direct testimony, there is no explicit capacity charge in the SSO rates. Further, as shown on Exhibit KMM-10, when specifically requested to identify the capacity component of its SSO rates, AEP-Ohio could not or chose not to do so. Thus, it is impossible to identify whether the proposed cost-based capacity charge that AEP-Ohio wants to impose on CRES providers is comparable to the capacity-related charge embedded in the default generation supply portion of the SSO prices.

**Q31. Why does comparability between the capacity-related charge that AEP-Ohio wants to impose on CRES providers and the capacity-related charge embedded in the default generation supply portion of the SSO prices matter?**

A31. AEP-Ohio has said repeatedly that it just wants to charge CRES providers the capacity charge that is embedded in its default generation supply price and that this will avoid non-shopping customers and AEP shareholders from subsidizing CRES providers or shopping customers. At the same time, AEP-Ohio has continued to maintain that the default generation supply prices are not based on cost and are not subject to examination on a cost-based methodology. What AEP-Ohio really seems to be doing is seeking a capacity charge that allows AEP-Ohio to avoid erosion to its non-cost based SSO revenue stream that would otherwise occur if RPM pricing is used, as AEP-Ohio has supported in the past, to set the capacity price paid by CRES providers. Because the proposed capacity charge applicable to CRES providers is a formula rate (changes per the formula), it would also be non-comparable to the structure of the SSO rate.

Also, even if AEP-Ohio’s default generation supply price was determined based on the same cost-based formula that AEP-Ohio proposes to use to set the capacity price charged to CRES providers, the structure of the default generation supply rate is very different than the unbundled per megawatt day rate design that applies to a CRES provider. In other words, the rate design between the two is not comparable and the structural differences make it impossible for a customer to develop a meaningful comparison, on an apples to apples basis, between the default generation supply price and pricing offers available from competitive suppliers.

**Q32. With regard to the non-comparable rate structures between the SSO pricing and the proposed capacity price for CRES providers, how could the structural non-comparability be remedied?**

A32. Assume the SSO residential rate totals $0.08 per kWh and that the embedded capacity portion of this rate was $0.02 per kWh. If the wholesale capacity price to CRES providers serving residential load in AEP-Ohio’s service area was unbundled to show a separate and comparable capacity charge within the SSO structure, AEP-Ohio would be economically indifferent to shopping from a capacity revenue standpoint. In other words, it would obtain the same (“comparable”) compensation for providing capacity generation service to a non-shopping customer as when the same customer elects to obtain service from a CRES provider.

However, under this same example, if the embedded capacity portion of the default generation supply price within the SSO was $0.02 per kWh and the wholesale capacity price charged to CRES providers was set at $0.04 per kWh, the results would not be comparable and the comparability violation would allow AEP-Ohio to bias customer choice in favor of decisions that favor the generation assets under its ownership or control, the structural problem that electric industry restructuring was designed to remedy. Thus, if the Commission did have authority to establish a cost-based rate, which I understand it does not, it is also my understanding that the rate levels and rate structures as between the default service option and the capacity pricing that applies to CRES providers must be comparable and non-discriminatory. In this proceeding, AEP-Ohio has presented no evidence to demonstrate that its proposed cost-based rate to be charged CRES providers is comparable to the default generation supply service and price of the SSO. Indeed, the combination of AEP-Ohio’s positions that it can, on the one hand, establish non-cost based default generation supply prices (which have historically been justified based on market price estimates) and, on the other hand, contemporaneously impose a cost-based capacity price formula on CRES providers defies the purpose of the concepts of comparability and non-discrimination; concepts that are key to successfully restructuring the electricity industry to allow competition to serve the public interest in reasonable prices and reliable service.

**III. DEMAND CURVE OPERATION**

**Q33. Do you agree with the statements in Dana E. Horton’s testimony that AEP-Ohio saved $25 million annually between 2007-2008 and 2014-2015 by selecting the FRR option?**

A33. No. The conclusions in Mr. Horton’s testimony are based upon an incorrect characterization of how the downward sloping demand curve operates in PJM. Mr. Horton’s calculations assume that the reserve margin for AEP would have increasedfrom approximately 15.5% to 19% over this time period and this would have resulted in higher costs to AEP-Ohio that would have been passed on to customers. There are two fundamental errors in Mr. Horton’s analysis.

First, a key feature of the downward sloping demand curve that is an integral part of RPM is that additional reserves will be procured and, in theory, increase reliability (a benefit) if the increased reserves can be obtained at a lower overall cost to customers. The slope of the demand curve is designed to ensure this result as a mathematical example helps to illustrate. Based upon Figure 2, page six, of Mr. Horton’s testimony, the price at the intersection of the demand curve at a 15% reserve margin is approximately $190 per MW-day. Procuring 22,000 MW of capacity (15% reserves for all of the AEP EDUs in PJM) would cost $4,180,000 a day or $1,525,700,000 annually. However, procuring 22,925 MW (22,000 MW plus the 925 MW identified in Mr. Horton’s testimony to achieve a 19.2% reserve) would result in a clearing price of $40 per MW-day as illustrated in Figure 2. At this price, the total cost of the higher level of the reserve is only $917,000 a day or $334,705,000 annually. Thus, Mr. Horton’s characterization that the higher reserve level through the use of the downward sloping demand curve results in a higher cost is incorrect.

Second, irrespective of what capacity costs are incurred by AEP-Ohio and as already discussed, SSO rates in Ohio have not been based upon cost since the implementation of SB3. As previously noted, when specifically requested to identify the capacity component of its SSO rates, AEP-Ohio could not or chose not to do so.

**IV. CAPACITY BILLING**

**Q34. Should the Commission require AEP-Ohio to provide customers and CRES providers additional information to verify they are being billed appropriately for capacity?**

A34. Yes. As previously noted, each PJM EDC is responsible for allocating its normalized previous summer’s peak to each customer in the zone (both retail and wholesale). To assure that capacity resources are appropriately allocated to shopping and non-shopping customers and that the allocation process does not discriminate, a transparent process is necessary.

The Commission should require AEP-Ohio to document to customers and CRES providers that the PLC factor it is assigning to customers corresponds with the customers’ PLC value recognized by PJM.[[6]](#footnote-6)

**V. CONCLUSION**

**Q35. What are your conclusions regarding AEP-Ohio’s request for a cost-based capacity charge?**

A35. A cost-based capacity charge would subsidize AEP-Ohio’s generation to the detriment of customers and competitors and is inconsistent with the state’s policies of the electric industry restructuring required to enable competitive markets for electricity generation service. As IEU-Ohio witness Hess’ testimony explains, AEP-Ohio’s proposal for pricing CRES provider capacity amounts to an untimely attempt to seek “transition revenue” in circumstances where AEP-Ohio previously agreed that it would not do so.

A cost-based capacity charge that uniquely applies to CRES providers is also inconsistent with how AEP-Ohio has, for its benefit, historically determined CRES provider capacity prices and how other affiliated AEP operating companies are establishing the capacity price for ratemaking purposes.

It is my understanding that the Commission does not have authority to economically regulate wholesale generation services and where the Commission does retain jurisdiction to establish generation supply prices, it must do so as part of the SSO process.

Additionally, it is my understanding that whatever prices the Commission may establish for services provided to consumers as well as CRES providers, they must be comparable and non-discriminatory.

Therefore, I recommend that the Commission reject AEP-Ohio’s application and promptly direct AEP-Ohio to restore the use of RPM-based capacity pricing in all cases where a CRES provider is serving a retail consumer within AEP-Ohio’s service area. I would also suggest that the protracted debate that has occurred on the subject of this proceeding has, itself, stymied the ability for consumers to identify options to reduce their electric bills through “customer choice” and that the experience in this case strongly suggests that the Commission should turn to a competitive bidding process to establish default generation supply prices.

**Q36. In your answer to question 35, you suggest that the Commission should use a competitive bidding process to establish default generation supply prices. AEP-Ohio has claimed that it cannot move to a competitive bidding process to set default generation supply prices until the current pool agreements are modified, corporate separation is complete, AEP-Ohio discontinues its FRR status and, perhaps, other things happen. Do you agree that competitive bidding must be put off as AEP-Ohio has claimed?**

A36. No, I do not agree.

First, it is my understanding that the FRR option provides AEP-Ohio with the opportunity to accelerate termination of its FRR status as a result of regulatory determinations made by a state regulatory authority. Specifically, Section 8.1(C)(3) of PJM’s RAA states “in the event of a State Regulatory Structural Change, a Party may elect, or terminate its election of, the FRR Alternative effective as to any Delivery Year by providing written notice of such election or termination to the Office of the Interconnection in good faith as soon as the Party becomes aware of such State Regulatory Structural Change but in any event no later than two months prior to the Base Residual Auction for such Delivery Year.” Thus, there is an opportunity to accelerate termination of the FRR status. Additionally, as previously noted, AEP-Ohio has represented to the Commission its FRR status would not interfere with a state-directed competitive bidding process and in order to expeditiously proceed with a competitive bidding process AEP-Ohio would sell capacity to winning bidders at prevailing RPM prices.

Second, AEP-Ohio has previously used market-based prices and competitive bidding to establish default generation supply costs in the case of the pricing structure applicable to Ormet Primary Aluminum Corporation[[7]](#footnote-7) and the former Ohio customers of Monongahela Power Company.[[8]](#footnote-8) And, in its first proposed ESP, AEP-Ohio also proposed to use a competitive bidding process to establish an escalating portion of the default generation supply price. As I described earlier, AEP-Ohio’s comments in Commission Case No. 07-796-EL-ATA, *et al.*, strongly endorsed the use of a competitive bidding process to set default generation supply prices. These actual or proposed AEP-Ohio uses of competitive bidding to set default generation supply prices demonstrate that AEP-Ohio’s position regarding the alleged barriers to the use of competitive bidding is very different than the position AEP-Ohio took in prior Commission proceedings.

With regard to corporate separation, it is my understanding that corporate separation has been a requirement since SB3 was enacted.

If, as AEP-Ohio now claims, a competitive bidding process has to be ignored as an obvious and, I believe, preferred answer to the question of how to set default generation supply prices, then I believe it is even more imperative to set CRES provider capacity prices based on RPM because an RPM-based capacity price will allow the competitive bidding process used to establish the RPM capacity prices to impose a market-based check on AEP-Ohio’s non cost-based default generation supply prices.

**Q37**. **Does this conclude your testimony?**

A37. Yes.

# Certificate of Service

I hereby certify that a copy of the foregoing *Direct Testimony of Kevin M. Murray on Behalf of Industrial Energy Users-Ohio* was served upon the following parties of record this 4th day of April 2012, *via* electronic transmission, hand-delivery or first class U.S. mail, postage prepaid.

/s/ Frank P. Darr

Frank P. Darr

Steve Nourse

Matthew Satterwhite

American Electric Power Service Corporation

1 Riverside Plaza, 29th Floor

Columbus, OH 43215

stnourse@aep.com

mjsatterwhite@aep.com

**Counsel for Columbus Southern Power Company and Ohio Power Company**

David F. Boehm, Esq.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 East Seventh Street, Suite 1510

Cincinnati, Ohio 45202

dboehm@BKLIawfirm.com

mkurtz@BKLIawfirm.com

**Counsel for the Ohio Energy Group**

Terry Etter

Maureen Grady

Assistant Consumers’ Counsel

Office of the Ohio Consumers’ Counsel

10 West Broad Street, Suite 1800

Columbus, Ohio 43215-3485

etter@occ.state.oh.us

grady@occ.state.oh.us

**Counsel for the Office of the Ohio**

**Consumers' Counsel**

Lisa McAlister

Thomas J. O’Brien

Bricker & Eckler LLP

100 South Third Street

Columbus, OH 43215

lmcalister@bricker.com

tobrien@bricker.com

**Counsel for The Ohio Manufacturers’ Association**

Richard L. Sites

General Counsel & Senior Director of Health Policy

Ohio Hospital Association

155 E. Broad Street, 15th Floor

Columbus, OH 43215-3620

ricks@ohanet.org

Thomas J. O’Brien

Bricker & Eckler LLP

100 South Third Street

Columbus, OH 43215

tobrien@bricker.com

**Counsel for Ohio Hospital Association**

M. Howard Petricoff

Stephen M. Howard

Lija Kaleps-Clark

Vorys, Sater, Seymour and Pease LLP

52 East Gay Street

PO Box 1008

Columbus OH 43216-1008

mhpetricoff@vorys.com

smhoward@vorys.com

lkalepsclark@vorys.com

**Counsel for Direct Energy Services, LLC and Direct Energy Business, LLC and Constellation NewEnergy, Inc. and Constellation Energy Commodities Group, Inc., Retail Energy Supply Association**

Mark A. Hayden

FirstEnergy Service Company

76 South Main Street

Akron, OH 44308

haydenm@firstenergycorp.com

John N. Estes III

Paul F. Wight

Skadden, Arps, Slate, Meagher

& Flom LLP

1440 New York Avenue, N.W.

Washington, DC 20005

john.estes@skadden.com

paul.wight@skadden.com

James F. Lang

Laura C. McBride

N. Trevor Alexander

Calfee, Halter & Griswold LLP

1400 KeyBank Center

800 Superior Ave.

Cleveland, OH 44114

jlang@calfee.com

lmcbride@calfee.com

talexander@calfee.com

David A. Kutick

Grant Garber

Jones Day

North Point

901 Lakeside Avenue

Cleveland, OH 44114

dakutik@jonesday.com

gwgarber@jonesday.com

Allison E. Haedt

Jones Day

P.O. Box 165017

Columbus, OH 43216-5017

aehaedt@jonesday.com

**Counsel for FirstEnergy Solutions Corp.**

Dorothy Kim Corbett

Associate General Counsel

Duke Energy Business Services LLC

139 East Fourth Street

Cincinnati, OH 45202

Dorothy.Corbett@duke-energy.com

Jeanne W. Kingery

Associated General Counsel

155 East Broad Street, 21st Floor

Columbus, OH 43215

Jeanne.Kingery@duke-energy.com

**Counsel for Duke Energy Retail Services, LLC**

Sandy I-ru Grace

Assistant General Counsel

Exelon Business Services Company

101 Constitution Avenue N.W.

Suite 400 East

Washington, DC 20001

sandy.grace@exeloncorp.com

**Counsel for Exelon Generation Company, LLC**

Mark A. Whitt

Melissa L. Thompson

Whitt Sturtevant LLP

PNC Plaza, Suite 2020

155 East Broad Street

Columbus, OH 43215

whit@whitt-sturtevant.com

thompson@whitt-sturtevant.com

Vincent Parisi

Matthew White

Interstate Gas Supply, Inc.

6100 Emerald Parkway

Dublin, OH 43016

vparisi@igsenergy.com

mswhite@igsenergy.com

**On Behalf of Interstate Gas Supply, Inc.**

Dane Stinson

Bailey Cavalieri LLC

10 West Broad Street, Suite 2100

Columbus, OH 43215

dane.stinson@baileycavalieri.com

**On Behalf of The Ohio Association of School Business Officials, The Ohio School Boards Association, The Ohio Schools Council and The Buckeye Association of School Administrators**

Chad A. Endsley

Chief Legal Counsel

Ohio Farm Bureau Federation

280 North High Street, P.O. Box 182383

Columbus, OH 43218-2383

cendsley@ofbf.org

**On Behalf of the Ohio Farm Bureau Federation**

Mark S. Yurick

Zachary D. Kravitz

Taft Stettinius & Hollister LLP

65 East State Street, Suite 1000

Columbus, OH 43215

myurick@taftlaw.com

zkravitz@taftlaw.com

**On Behalf of The Kroger Co.**

Jeanne W. Kingery

Associate General Counsel

Amy B. Spiller

Deputy General Counsel

139 E. Fourth Street, 1303-Main

P.O. Box 961

Cincinnati, OH 45201-0960

Jeanne.Kingery@duke-energy.com

Amy.Spiller@duke-energy.com

**On Behalf of Duke Energy Commercial Asset Management, Inc.**

Barth E. Royer

Bell & Royer Co., LPA

33 South Grant Avenue

Columbus, OH 43215-3927

BarthRoyer@aol.com

Gary A. Jeffries

Assistant General Counsel

Dominion Resources Services, Inc.

501 Martindale Street, Suite 400

Pittsburgh, PA 15212-5817

Gary.A.Jeffries@dom.com

**On Behalf of Dominion Retail, Inc.**

Roger P. Sugarman

Kegler, Brown, Hill & Ritter

65 East State Street, Suite 1800

Columbus, OH 43215

rsugarman@keglerbrown.com

**On Behalf of the National Federation of Independent Business**

C. Todd Jones

Stephen J. Smith

Gregory H. Dunn

Christopher L. Miller

Asim Z. Haque

Ice Miller LLP

250 West Street

Columbus, OH 43215

Gregory.dunn@icemiller.com

christopher.miller@icemiller.com

asim.haque@icemiller.com

**On Behalf of the Association of Independent Colleges and Universities of Ohio and the City of Grove City, Ohio**

Brian P. Barger

Brady, Coyle & Schmidt, LTD.

4052 Holland-Sylvania Road

Toledo, OH 43623

bpbarger@bcslawyers.com

**On Behalf of the Ohio Construction Materials Coalition**

Emma Hand

SNR Denton

1301 K Street NW

Suite 600, East Tower

Washington, DC 20005-3364

Emma.hand@snrdenton.com

**On Behalf of Ormet Primary Aluminum Corporation**

Michael R. Smalz

Joseph V. Maskovyak

Ohio Poverty Law Center

555 Buttles Avenue

Columbus, OH 43215-1137

msmalz@ohiopovertylaw.org

jmaskovyak@ohiopovertylaw.org

**On Behalf of the Ohio Poverty Law Center**

David Rinebolt

231 West Lima Street

PO Box 1793

Findlay, OH 45839-1793

drinebolt@ohiopartners.org

**On Behalf of Ohio Partners for Affordable Energy**

Thomas Lindgren

Public Utilities Section

Ohio Attorney General's Office

180 East Broad Street, 6th Floor

Columbus, OH 43215

thomas.lindgren@puc.state.oh.us

**On Behalf of the Staff of the Public Utilities Commission of Ohio**

Greta See

Jeff Jones

Sarah Parrot

Attorney Examiners

Public Utilities Commission of Ohio

180 East Broad Street, 12th Floor

Columbus, OH 43215

Greta.See@puc.state.oh.us

Jeff.jones@puc.state.oh.us

Sarah.Parrot@puc.state.oh.us

1. Section 4928.12, Revised Code. [↑](#footnote-ref-1)
2. Reliability Assurance Agreement Among Load Serving Entities in the PJM Region, Schedule 8.1, § D.8 (“Fixed Resource Requirement Alternative”) (emphasis added). [↑](#footnote-ref-2)
3. The total bundled price for each electric rate schedule established the total rate cap, which is then divided between the functional components (generation, transmission, and distribution). Ohio provided, in Section 4928.34(A)(6), Revised Code, that such rate cap was subject to adjustment for changes in taxes, costs related to the establishment of a universal service fund (“USF”), and a temporary rider established by Section 4928.61, Revised Code. Thus, the rate cap was not an absolute cap on the total charges paid by customers during the MDP. [↑](#footnote-ref-3)
4. The press release is available *via* the Internet at http://www.aep.com/newsroom/newsreleases/?id=1712 (last accessed March 28, 2012). [↑](#footnote-ref-4)
5. Motion for Relief and Request for Expedited Ruling at 5 (February 27, 2012). [↑](#footnote-ref-5)
6. Each PJM EDC is responsible for allocating the previous summer’s weather normalized peak to end-use customers in the zone (both retail and wholesale) and providing this information to PJM by December 31 prior to the start of the delivery year. [↑](#footnote-ref-6)
7. *Columbus Southern Power Company’s and Ohio Power Company’s Application to Set the 2007 Generation Market Price for Ormet’s Hannibal Facilities*, PUCO Case No. 06-1504-EL-UNC, Columbus Southern Power Company’s and Ohio Power Company’s Ormet-Related 2007 Generation Market Price Submission (December 26, 2006). See, also, *Columbus Southern Power Company’s and Ohio Power Company’s Application to Set the 2007 Generation Market Price for Ormet’s Hannibal Facilities*, PUCO Case No. 06-1504-EL-UNC, Entry (June 27, 2007); and *Columbus Southern Power Company’s and Ohio Power Company’s Application to Set the 2008 Generation Market Price for Ormet’s Hannibal Facilities*, PUCO Case No. 07-1317-EL-UNC, Columbus Southern Power Company’s and Ohio Power Company’s Ormet-Related 2008 Generation Market Price Submission (December 27, 2007). [↑](#footnote-ref-7)
8. *In the Matter of the Transfer of Monongahela Power Company’s Certified Territory in Ohio to the Columbus Southern Power Company*, PUCO Case No. 05-765-EL-UNC, Opinion and Order (November 9, 2005). [↑](#footnote-ref-8)