BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Duke Energy Ohio, Inc., for the Establishment of a Charge Pursuant to Revised Code Section 4909.18.	))))	Case No. 12-2400-EL-UNC
In the Matter of the Application of Duke Energy Ohio, Inc., for Approval to Change Accounting Methods.	)))	Case No. 12-2401-EL-AAM
In the Matter of the Application of Duke Energy Ohio, Inc., for the Approval of a Tariff for a New Service.	)))	Case No. 12-2402-EL-ATA

DIRECT TESTIMONY OF

SCOTT W. NIEMANN, PH.D.

ON BEHALF OF

DUKE ENERGY OHIO, INC.

_____ Management policies, practices, and organization

_____ Operating income

_____ Rate base

_____ Allocations

_____ Rate of return

_____ Rates and tariffs

__X__ Other: PJM construct and market issues

March 1, 2013

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Scott W. Niemann. My business address is 401 Edgewater Place, Suite 640, Wakefield, Massachusetts 01880.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a Director and Principal of ESAI Power LLC, an economic research and consulting firm focusing on the electric power and natural gas industries.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I have 15 years experience advising industry participants and policy makers in the wholesale electricity industry on a broad range of economic and business issues. The primary focus of my consulting is in the areas of wholesale electricity market analysis, electricity market design and restructuring, regulation, and business strategy in the U.S. electricity industry. In this context, I have advised clients and conducted quantitative studies related to various business and regulatory issues affecting wholesale markets for electric power, installed generating capacity, and operating reserves. My work has focused on a broad range of issues including resource adequacy, fuel prices, fuel supply, environmental regulations, market structure, locational marginal pricing, financial transmission rights, seams issues, and market power. I have conducted studies and made numerous presentations to senior management of utility and merchant power clients, rating agencies, the investment community, market operators, and the U.S. Department of Justice. I have routinely been retained as a market expert both in support of asset transactions and in the context of litigation and regulatory proceedings.

Prior to joining ESAI in January of 2013, I was a Vice President in the Energy Practice of Charles River Associates (CRA). Prior to joining CRA in 2001, I was a Principal Consultant in the Energy Economics Practice of PA Consulting Group. I hold a B.A. degree in Mathematics, Economics, and Political Science from the University of Kansas and M.S. and Ph.D. degrees in Economics from the University of Wisconsin. My resume is attached as Exhibit SWN-1.

Much of my work has focused on the organized markets in the Northeast US, including the market operated by the PJM Interconnection, L.L.C. (PJM). I have routinely advised clients about the economic fundamentals, market rules, and regulatory issues in each of these markets, focusing in particular on the commercial implications and financial risks. Much of my work over the last six years has focused on evolving rules and market structures in the markets for installed capacity, including the PJM Reliability Pricing Model (RPM) capacity market. As part of this work, I have led the development of detailed models of the capacity markets administered by various independent system operators, which capture both the market fundamentals and detailed rules behind each market design. I have been actively involved in advising numerous market participants on the outlook for each of these markets and the commercial implications of market rules, such as seller and buyer market power mitigation procedures. In addition to work with resource owners and capacity suppliers, I have advised Load Serving Entities about expected capacity procurement costs and the rules for allocation of those costs within centralized capacity markets.

I have provided expert testimony focused on capacity markets on several occasions. Regarding the New York ISO Capacity market and, more specifically, New

York City, I testified on behalf of the New York City Economic Development Corporation (NYCEDC) in Case 08-T-0034 before the New York Public Service Commission, the Article VII siting application for the Hudson Transmission Partners (HTP) HVDC transmission cable project. My testimony in that case focused in part on the impact of the HTP project on capacity prices and capacity costs for New York City. On behalf of Brookfield Power, I provided testimony related to implementation of buyer market power rules for New York City in Docket EL11-50 before the Federal Energy Regulatory Commission (FERC). I also provided testimony to the FERC in Docket No. EL08-58-000, which focused on implementation of performance incentives rules in the RPM market rules. I have also testified before state commissions in Connecticut and Ohio about capacity market rules and price forecasts under the ISO-NE Forward Capacity Market and the PJM RPM market. Finally, I represented a generation owner during the RPM settlement proceeding before the FERC.

I have also been retained on numerous occasions as an independent market advisor supporting asset transactions in PJM and other markets, including the acquisition or financing of assets that are expected to generate cash flows predominantly from the RPM market. In this role, I have assisted market participants with their due diligence efforts, including detailed review of the RPM market rules and market fundamentals. I have also advised rating agencies and debt and equity investors regarding the commercial implications of various aspects of the PJM rules.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO?

A. Yes. I provided direct and supplemental testimony on behalf of The Dayton Power and

Light Company in Case No. 08-1094-EL-SSO, *et al*.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THESE PROCEEDINGS?

A. I am testifying about PJM's RPM capacity market in the context of the Application by Duke Energy Ohio, Inc., (Duke Energy Ohio or Company) for cost recovery for capacity resources that the Company has committed for meeting its obligations as a PJM Fixed Resource Requirement (FRR) entity through May 31, 2015.[1] In addition to providing a general description of the RPM construct and the associated provisions within the PJM Open Access Transmission Tariff (OATT) and Reliability Assurance Agreement (RAA), I specifically discuss the FRR mechanism within RPM, which Duke Energy Ohio must utilize in meeting its capacity obligations in PJM through May 31, 2015. Under the FRR mechanism, Duke Energy Ohio is obligated to secure capacity outside of the centralized PJM auctions, in order to meet the capacity obligations for both Duke Energy Ohio and all other suppliers whose customers are served by its distribution system and did not elect to meet their resource requirements through self-supply. The PJM OATT and RAA specify the obligations for FRR entities and the options for compensation to FRR entities for supplying capacity. Finally, I discuss why the proposed compensation mechanism should not be expected to adversely affect the outcomes in the RPM market or competition among suppliers in either the RPM market or the Ohio retail market.

Q. PLEASE SUMMARIZE YOUR PRINCIPAL CONCLUSIONS.

A. First, there are substantial risks for an FRR entity that differ from an entity that participates in the Base Residual Auction (BRA). An FRR entity must secure and commit resources to cover the full resource requirements for the load of all of its

[1] *In the Matter of the Application of Duke Energy Ohio, Inc., for the Establishment of a Charge Pursuant to Revised Code Section 4909.18,* of Duke Energy Ohio, Inc., Case No. 12-2400-EL-UNC, *et al.* (August 29, 2012).

distribution customers in advance of the BRA. An FRR entity has less flexibility to adjust to changes in its resource requirement between the BRA and the Delivery Year than a BRA participant, and therefore may face higher costs from a surplus that results from a lower demand forecast. An FRR entity also faces greater penalties for failing to provide capacity compared to a BRA participant, and it bears the risk of those penalties not only for its own resource requirements, but also for the requirements of other suppliers serving its distribution customers.

Second, the compensation mechanism proposed by Duke Energy Ohio in its Application is compatible with the existing PJM market rules for the RPM market and the FRR mechanism. The PJM rules do not and are not intended to address recovery of embedded costs. Rather, that issue is properly addressed by state regulatory policy. As such, the FRR requirements do not dictate a particular means of compensation to the FRR entity for its cost of supplying capacity, but rather are designed to accommodate different business models and regulatory approaches. A principal difference between the BRA and the FRR process is that, in the FRR process, the FRR entity must meet all capacity needs within its footprint, in order to maintain reliability. This mandate, while temporary in Duke Energy Ohio's case, is basically a regulatory service obligation, not unlike the historic service obligation of Ohio utilities prior to restructuring. As with other such service obligations, it is appropriate to consider the FRR service obligation in the context of cost-based ratemaking, which warrants recovery of embedded costs.

Third, the cost recovery requested by Duke Energy Ohio achieves the objective of cost recovery for the FRR service obligation without distorting prices or outcomes in the competitive wholesale or retail markets. The deferred cost recovery requested by Duke

Energy Ohio will not materially affect the mix of resources used to meet PJM reliability requirements, or the clearing prices in RPM auctions. For each Delivery Year for which compensation has been requested, the FRR plan for meeting obligations in the Duke Energy Ohio service area has been established and resources for meeting capacity obligations elsewhere in PJM have been secured through the BRAs or other FRR plans. Moreover, the resources included in the Company's FRR plan were or would have been economic in the BRA or transitional procurement process for each relevant RPM Delivery Year, so neither the mix of supply nor the market pricing would have been materially different had Duke Energy Ohio met its resource requirement through the PJM auctions rather than an FRR plan, or been compensated through BRA pricing rather than a state compensation mechanism. Hence, the question of compensation and cost recovery can be addressed separately from market pricing, without concern about market distortions for the relevant Delivery Years.

Finally, the recovery of the deferred balance will not affect the rate paid by Ohio Load Serving Entities (LSEs) for capacity, and therefore will not distort competition. Nor will recovery of the deferred balance affect competition in the wholesale market, since it will be independent of clearing prices or the supply of resources by Duke Energy Ohio (or an affiliate to which assets may be transferred) in future RPM auctions, leaving Duke Energy Ohio (or its affiliate) with no competitive advantage or subsidy affecting incentives to offer or clear capacity in the capacity market.

II. DISCUSSION

Q. PLEASE DESCRIBE THE RPM CONSTRUCT AND HOW CAPACITY TO MAINTAIN RESOURCE ADEQUACY IS SECURED IN PJM.

A. PJM, as reliability coordinator, sets capacity requirements for the overall PJM regional transmission organization (RTO) and transmission constrained regions within PJM. Based on reliability studies, PJM establishes a minimum Installed Reserve Margin (IRM) for the entire RTO. Applying that IRM value to forecasted peak load and adjusting for the forced outage rate of the fleet, PJM establishes a minimum level of Unforced Capacity needed to maintain its reliability criterion, called the Reliability Requirement. Additionally, for transmission constrained regions, referred to as Locational Deliverability Areas (LDAs), PJM establishes local Reliability Requirements. These Reliability Requirements, when allocated to LSEs based on peak load share, establish the resource requirements that must be supplied to LSEs.

Through a FERC settlement process, PJM, along with stakeholders, established the RPM construct to provide a framework for securing supply to meet the PJM reliability requirements. I was active in the settlement process. The Settlement Agreement resulting from the process received FERC approval in 2006.[2] The RPM mechanism is governed by rules set forth in Attachment DD to the PJM OATT, and Article 7 and Schedule 8 of the RAA.

Q. HOW DOES THE RPM CONSTRUCT HELP TO MAINTAIN RELIABILITY?

A. RPM provides a mechanism through which PJM secures financially binding commitments from market participants to provide the resources needed to maintain reliability and allocates the resulting costs to LSEs. Commitments to supply the capacity needed to meet reliability requirements are established through two means: (1) procurement of capacity through a market-based, PJM-administered forward auction process; or (2) by an individual entity obligated under FRR to provide the capacity

[2] Settlement Agreement and Offer of Settlement, Section V, FERC Docket ER05-1410-000 (September 26, 2006).

necessary to maintain reliability within its footprint. The PJM region is effectively divided each year such that these two means of satisfying reliability do not overlap; the auction process applies to some areas, while FRR applies to others. The FRR process affects the auction process only indirectly through the set of resources available to participate in the auctions and the level of resource requirements that remain to be met with supply in the auctions. So far, the auction process has been predominant, and has been used for much of PJM. Although the auction process and FRR share the same goal of maintaining reliability by ensuring an adequate supply of deliverable capacity, they meet that goal in ways that are fundamentally different.

Q. PLEASE EXPLAIN HOW THE PJM-ADMINISTERED FORWARD AUCTION PROCESS RESULTS IN THE PROVISION OF CAPACITY TO HELP MAINTAIN RELIABILITY IN AREAS OF PJM WHERE THE AUCTION IS A MEANS OF PROVIDING CAPACITY.

A. The primary means for securing capacity resources under RPM is through PJM-administered forward auctions. Each year, PJM conducts a BRA in which resources are procured to meet the pool-wide and locational requirements for the 12-month Delivery Year commencing approximately three years later. PJM acts as a central buyer in the auction and then allocates the procurement costs back to LSEs pro rata, based zonal shares of peak PJM coincident peak load and Peak Load Contributions (PLCs) of LSEs in each zone. The price charged to each LSE to cover the costs of capacity procured in the PJM RPM auctions is referred to as the final zonal capacity price (FZCP).

The BRA determines both a price and a quantity procured for each Delivery Year and LDA by clearing offers from suppliers against a set of administrative demand curves,

referred to as the Variable Resource Requirement (VRR) curves. A VRR curve is established for the RTO and each LDA. The VRR curves are centered around a target level of capacity, equal to the Reliability Requirement plus one percent, and a price level equal to the estimated net cost of new entry (Net CONE) for each LDA. Net CONE is set based on the estimated all-in, levelized annual cost of building a new combustion turbine generating unit, less the gross margin that could be earned from the sale of energy and ancillary services provided by the unit. For the 2012/13 Delivery Year, Net CONE for the unconstrained PJM RTO area, which is applicable to Ohio, is $112,868/MW-year. The VRR curve provides a mechanism by which the auctions can clear with more or less capacity than is needed to meet the PJM Reliability Requirements, with the price declining as the level of capacity increases.[3] As a result, the expected resource requirement for LSEs participating in the BRA is not know until the auction has cleared.

LSEs participating in the BRA can hedge capacity obligations through bilateral purchases, but the capacity resources must still be cleared through the BRA in order to be counted against the Reliability Requirements and offset the LSE's obligations. Following each BRA, PJM conducts annual incremental auctions up to the start of the Delivery Year. The positions of market participants can also be rebalanced through the incremental auctions to account for changes in unit ratings or forced outage rates. Additionally, the final capacity obligations of an LSE may be adjusted to reflect changes in peak load forecasts and resulting resource requirements and supply obligations. The suppliers with resources committed through this process have binding financial commitments to provide the capacity needed to meet the resource requirements satisfied

[3] The target level of capacity for the BRA is adjusted to exclude 2.5 percent of the minimum Reliability Requirement in order to reserve some demand that can be met by resources with supply timelines less than three years.

through the auctions and must make the capacity available in the PJM energy markets, ensuring the target level of reliability will be maintained.

Q. PLEASE EXPLAIN HOW THE FRR PROCESS RESULTS IN THE PROVISION OF CAPACITY TO HELP MAINTAIN RELIABILITY IN AREAS OF PJM WHERE FRR IS THE MEANS OF OBTAINING CAPACITY.

A. The FRR option allows an entity with metered boundaries, such as a utility, to opt out of the auction process and instead satisfy the capacity resource requirement for its footprint with designated resources from its fleet or with resources secured through bilateral transactions.[4] An entity that elects the FRR option must submit an FRR Capacity Plan that designates the resources it has secured to meet its resource requirement. With limited exceptions that allow early termination, an entity that elects the FRR option must do so for an initial minimum period of five Delivery Years and must submit an initial FRR Capacity Plan for that full five-year period. After the initial five years, an FRR entity may choose to continue under the FRR option and submit an updated FRR Capacity Plan each year in advance of the BRA. If an FRR entity terminates its FRR election, it cannot again become an FRR entity for at least five years.

The resource requirement for an FRR entity is based on the load for all customers served through its distribution system, including those served by competitive retail suppliers or other LSEs. Prior to the submission of the FRR entity's Capacity Plan, LSEs in the FRR Service Area may opt out of the plan and secure capacity resources separately through an independent resource plan. The FRR entity has an obligation to provide all remaining capacity resources for the LSEs in its service area. This is an important point

[4] Under Section B(1) of Schedule 8.1 of the RAA, eligible FRR entities include Investor Owned Utilities, Electric Cooperatives, and Public Power entities.

worth emphasizing: under the RAA, which is a rate filed with FERC and to which RAA signatories like Duke Energy Ohio are bound, an FRR entity like Duke Energy Ohio is *required* to supply the capacity for its footprint. The capacity is not procured through an auction, or any other PJM-administered, market-based process. Although entities within the footprint have self-supply options, Duke Energy Ohio must provide the capacity for its own load and the load of any other entity within its footprint that does not self-supply.

Q. WHAT WOULD HAPPEN IF AN FRR ENTITY LIKE DUKE ENERGY OHIO FAILED TO PROVIDE CAPACITY FOR ITS FOOTPRINT, AS REQUIRED BY THE RAA?

A. If Duke Energy Ohio failed to provide the full amount of capacity for its footprint as required by the RAA, the Company would be subject to a substantial penalty – the FRR Commitment Insufficiency Charge of two times net CONE per MW of shortage, regardless of whether that MW is needed to serve Duke Energy Ohio's own retail load or the retail load of a competitive retail supplier. For the current 2012/13 Delivery Year, that charge would be two times $276.09/MW-day, or $201,546 per MW of shortage for the Delivery Year.

Q. IS IT APPROPRIATE FOR DUKE ENERGY OHIO TO RECEIVE COST RECOVERY DIFFERENT FROM THE AUCTION-DETERMINED PRICES FOR CAPACITY?

A. Yes. Although FRR and the BRA have the same ultimate goal of preserving reliability by ensuring a sufficient supply of capacity, as I have explained, they go about it in dramatically different fashion. Simply put, in the portion of PJM where the BRA is used to procure capacity, the price is market-determined. But in FRR regions, capacity pricing

is not necessarily set by the market. The BRA does not include generation or load that is subject to FRR and generation and load that are subject to FRR are not included in the BRA. To be sure, the BRA market can serve as a useful benchmark, as it will continue to serve as the charge to alternative suppliers. But when it comes to determining the appropriate amount to recover, use of the market price as a benchmark ignores an important distinction of FRR. Under FRR, the FRR entity has a service obligation to supply all capacity resources for its footprint. How the costs of meeting that service obligation are recovered is a regulatory ratemaking question completely separate from the pricing in the auctions through which the remain resource requirements for other parts of PJM are met.

PJM market participants that participate in the BRA must offer existing generation that they own into the BRA in certain circumstances, but the responsibilities of an FRR entity run far deeper. The FRR entity must supply capacity whether it has sufficient existing capacity or not. That means that the FRR entity must plan how it will meet load, and perhaps procure capacity through the market, or even construct additional generation. And while a participant in the BRA can be penalized if its generation that it has cleared in the BRA is not available at the designated time, an FRR entity's penalty exposure is not limited to failure to supply its own generation. Under the broader responsibilities of an FRR entity, the FRR entity can be penalized if it fails to procure sufficient capacity to meet the resource requirements for all load in its footprint, regardless of whether it owns the needed capacity or not. This responsibility makes the FRR responsibility very similar to the traditional, pre-restructuring resource planning responsibility of vertically integrated utilities. Typically, utilities operating in such

environments are entitled to recover their embedded cost of service. Indeed, where as here there is a deep-seated obligation to serve, full cost recovery is generally thought necessary to avoid a confiscatory rate.

Q. ARE YOU RECOMMENDING THAT DUKE ENERGY OHIO BE ALLOWED TO RECOVER ITS EMBEDDED COST OF SERVICE?

A. Yes. As I discussed in the prior answer, I view Duke Energy Ohio's circumstances as an FRR entity as being more similar to those of a pre-restructuring utility with an obligation to serve than to an entity operating in an environment where the provider of services (and hence the price of service) is determined through a market.

Q. HOW ARE CAPACITY COSTS DETERMINED AND RECOVERED FOR AN FRR ENTITY AND OTHER LSEs WITHIN ITS FRR SERVICE AREA?

A. The capacity costs for supplying resources under the FRR plan will be the cost of the FRR entity's self-supplied resources plus and bilateral purchases. How those costs are recovered from the FRR entity's retail customers is outside of PJM market rules and will be determined by the regulatory and rate structure in place for its retail customers. The potential mechanisms for recovery of costs associated with the resource requirements of other LSEs in the FRR Service Area are established in Schedule 8.1 of the RAA. Section D(8) of that schedule states:

> 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.

Under this provision of the RAA, a state regulatory jurisdiction may establish the mechanism and rate by which alternative LSEs pay an FRR entity for capacity included in its FRR plan. Compensation at the BRA capacity price is specified in the RAA as a default rate, which applies only in the case in which no state compensation mechanism is in place. However, compensation under a state compensation plan at a rate other than the BRA capacity price is in no way precluded by the RAA, and would take precedence over the default rate based on the BRA capacity price. In fact, even outside of a state compensation mechanism, the RAA allows the option for an FRR Entity to propose a different, just and reasonable basis for compensation through a Section 205 filing with FERC. Hence, the RAA is prescriptive of the rate charged to other LSEs in an FRR Service Area and only in the case when no rate has been established through a state compensation mechanism or a FERC-approved mechanism.

Q. IS A COMPETITIVE RETAIL SUPPLIER OBLIGATED TO RELY ON THE FRR PLAN TO MEET ITS RESOURCE REQUIREMENT FOR CUSTOMERS IN AN FRR SERVICE AREA?

A. No. Under Section D(9) of Schedule 8.1 of the RAA, a competitive retail supplier can self-supply capacity under certain circumstances. But if they do not, the FRR entity is responsible to provide the resources. This provision would have allowed other LSEs in the Duke Energy Ohio service area the ability to secure capacity to meet resource requirements independently, rather than relying on the Company's FRR plan. If an LSE

did not opt out through this provision, the service obligation remained with Duke Energy Ohio.

Q. ARE THERE DIFFERENCES IN THE OBLIGATIONS FOR AN FRR ENTITY RELATIVE TO THOSE OF AN ENTITY THAT PARTICIPATES IN THE BRA?

A. Yes. First, there can be a difference in the amount of capacity that each entity must procure. As I discussed earlier in my testimony, an FRR entity is responsible for procuring resources to cover a fixed, rather than variable, resource requirement, which may differ from the resource requirement resulting from the BRA clearing process. Additionally, an FRR entity is responsible for establishing an FRR plan to meet its full expected Reliability Requirement for a given Delivery Year, no later than one month prior to the BRA for that Delivery Year. In the case of Duke Energy Ohio's transition to PJM, the Company was required to establish an FRR plan for the 2011/12, 2012/13, and 2013/14 Delivery Years prior to its integration into PJM on January 1, 2012. Furthermore, in the BRA, PJM secures only 97.5 percent of the capacity needed to meet the expected resource requirements for participating LSEs, leaving 2.5 percent to be procured in incremental auctions, with the goal of allowing participation by short-term resources that may not be able to make a supply commitment at the time of the BRA. Hence, an FRR entity is responsible for securing resources to cover 100 percent of its resource requirement, typically three years in advance, while on the same three-year-ahead timeframe, resources will be locked in for only 97.5 percent of the expected reliability requirements for LSEs relying of the BRA.

An FRR entity is also restricted in its ability to sell surplus resources in the RPM auctions. An FRR entity is allowed to offer into RPM auctions only resources in excess

of its resource requirement, plus the lesser of 3 percent or 450 MW. The quantity of resources that an FRR entity may sell into the RPM auctions is also limited to the lesser of 1,300 MW or 25 percent of its resource requirements. Thus, participation in FRR can significantly limit the ability of an FRR entity to directly recover costs of generation that is not being used to supply FRR requirements.

Q. DOES AN FRR ENTITY FACE DIFFERENT RISKS THAN AN LSE PARTICIPATING IN THE PJM AUCTIONS?

A. Yes. An FRR entity is subject to additional risks related to changes in the peak load forecast, as compared to an entity participating in the BRA and incremental auctions. If the final load forecast in advance of the delivery year is lower than the preliminary forecast used to set the resource requirements for the BRA for that delivery year, both the FRR entity and the BRA participant may have to face costs for procurement of more capacity than will ultimately be needed to meet their final requirement. However, because the capacity secured to meet BRA demand covers 97.5 percent of the expected Variable Resource Requirements of BRA participants, while the FRR entity would be responsible for an FRR plan than included 100 percent of its resource requirement, or 103 percent if it had opted to be eligible to offer surplus resources in the auctions, the FRR entity faces a greater risk of having over-procured capacity. In other words, if the final resource requirement is below the level expected prior to the BRA for a Delivery Year, the FRR entity may be left with more "orphaned" resources secured three years in advance, but ultimately not needed to meet resources requirements, than would entities relying on the BRA. Additionally, because an FRR entity is responsible for including the resource requirements for all LSEs in its service area (excluding those that opt out), it

faces the risk of bearing costs for orphaned resources associated with its own load as well as the load of all other LSEs in its FRR Service Area.

Q. FOR WHICH DELIVERY YEARS IS DUKE ENERGY OHIO AN FRR ENTITY?

A. Duke Energy Ohio joined PJM on January 1, 2011. At that time, capacity had already been procured through BRAs for the remainder of the 2011/12 Delivery Year, the 2012/13 Delivery Year, and the 2013/14 Delivery Year. Accordingly, Duke Energy Ohio could not participate in the BRAs for those years. Thus, while FRR is generally thought of as an option, it was not for Duke Energy Ohio. Rather, the Company had no choice but to become an FRR entity. Duke Energy Ohio established a transitional FRR Plan to cover its resource requirements for this transitional FRR period, meeting the requirements with a combination of its own resources and bilateral purchases. Additionally, Duke Energy Ohio satisfied its resource requirement for the 2014/15 Delivery Year through its FRR Plan. Prior to the BRA for the 2015/16 Delivery Year, the Company informed PJM it planned to terminate its FRR status one year early due to a State Regulatory Structural Change, as permitted under Section C(3) of Schedule 8.1 in the RAA. PJM acknowledged the termination of Duke Energy Ohio's FRR status and Duke Energy Ohio participated in the BRA for the 2015/16 Delivery Year.

Q. WHAT ARE DUKE ENERGY OHIO'S OBLIGATIONS AS AN FRR ENTITY FOR THESE DELIVERY YEARS?

A. Duke Energy Ohio is responsible for providing sufficient capacity to meet the expected resource requirements, based on the load of all distribution customers in its service area. Duke Energy Ohio is subject to penalties for non-performance and capacity shortfalls relative to its resource requirement. Although the PJM peak load forecast has declined

significantly since the Company's FRR plan was developed, Duke Energy Ohio remains responsible for the costs of the resources it secured. While, in principle, surplus resources could be sold in PJM incremental auctions, Duke Energy Ohio is subject to the minimum threshold resource level (resource requirement plus 3 percent) and maximum sales limit (25 percent) for FRR entities. Additionally, given the sharp decline in forecasted peak load, incremental RPM auction prices have been very low.

Q. HOW WILL DUKE ENERGY OHIO RECOVER THE EMBEDDED COSTS OF CAPACITY INCLUDED IN ITS FRR PLAN, COVERING ITS OBLIGATIONS THROUGH MAY 31, 2015?

A. The Company does not now have any mechanism to recover such costs. Duke Energy Ohio sells the required capacity to PJM, under PJM's standard tariffs. Duke Energy Ohio thereby receives from PJM the FZCP for each applicable Delivery Year. The FZCP for the 2011/12 Delivery Year is $116.15/MW-day and the FZCP for the 2012/13 Delivery Year is $16.74/MW-day. The FZCP for the 2013/14 and the 2014/15 Delivery Years will be determined after the remaining incremental auctions for each Delivery Year have been conducted. For 2013/14, the BRA clearing price was $27.73/MW-day and for 2014/15 the BRA clearing price was $125.99/MW-day.[5] As discussed in detail in Duke Energy Ohio's Application and the Direct Testimony of other Company witnesses in these proceedings, the FZCP is well below the fully embedded cost of the resources included in the Duke Energy Ohio FRR plan. Duke Energy Ohio is seeking a deferral of the unrecovered embedded costs, and subsequent recovery of such deferred costs through a non-bypassable charge to all of its distribution customers.

[5] The 2014/15 price of $125.99/MW-day applies to generation, annual demand resources, and extended summer demand response. Limit demand response resources will receive a slightly lower price of $125.47/MW-day.

Q. IS RECOVERY OF DUKE ENERGY OHIO'S EMBEDDED COSTS PRECLUDED BY THE TERMS OF THE RAA?

A. No. As I discussed earlier, the RAA allows compensation through a state compensation mechanism and, when such a mechanism has been established, it prevails over the default rate of the BRA clearing prices. The RAA also expressly contemplates the possibility of development, in a FERC proceeding, of a rate. It would make no sense for the RAA to describe three different ways to develop a rate if all of them were intended to have the same result, *i.e.*, the default BRA rate. The only natural reading that I can see of this provision is that non-BRA rates are permitted, and, for the other reasons that I have given above, it is reasonable and expected that embedded cost rates should fairly be considered to be within the scope of these alternative rates.

Q. ARE THERE MARKET EFFICIENCY CONSIDERATIONS ASSOCIATED WITH THE RECOVERY OF EMBEDDED COSTS?

A. Yes, potentially. Efficient market prices may or may not be sufficient to cover embedded costs of suppliers. Hence, recovery of embedded costs may require compensation outside of competitive markets. Any non-market compensation mechanism implemented to meet the regulatory objective of fair compensation should be developed with the objective of minimal impact on market efficiency.

The question of whether and how embedded cost for a service mandate should be recovered is a policy and regulatory question. If the policy and regulatory framework is to support a reasonable return on investments necessary to fulfill a unique and noncompetitive obligation, implementation of a mechanism to provide compensation for embedded costs in a manner that does not distort the competitive market outcomes, such

as that proposed by Duke Energy Ohio, is appropriate. From an economic perspective, it is preferable to implement a recovery mechanism with the least possible impact on efficient market outcomes. The recovery mechanism requested by Duke Energy Ohio meets this objective, and in fact will not have any material impact on market efficiency.

Q. WHY WILL RECOVERY OF DUKE ENERGY OHIO'S EMBEDDED COSTS NOT HAVE ANY DISTORTIONARY IMPACT ON RPM MARKET OUTCOMES?

A. First, the embedded cost recovery being requested applies to Delivery Years for which the BRAs have already occurred. Hence, the proposed recovery of the deferred balance for those periods will have absolutely no effect on either the resources cleared or the market clearing prices in those auctions.

Additionally, because Duke Energy Ohio is seeking to recover its embedded costs to supply capacity for its entire footprint on a deferred basis through a non-bypassable charge to all distribution customers, the recovery of embedded costs does not depend on the status of the Duke Energy Ohio assets, and hence is completely separated from the incentives affecting offers for the capacity. In other words, because the embedded costs to be recovered are associated with resources for which the supply decisions have already occurred, the payments cannot distort the efficiency of future supply. Rather, Duke Energy Ohio incentives for how to offer the capacity in future BRAs will remain well-aligned with competitive market incentives.

Finally, the Duke Energy Ohio FRR plan does not include any resources that would not have been economic in the relevant BRAs. Based information provided by the Company, I have confirmed that the offer caps that would have been in place for the

assets if they had been offered into the BRA, all of the resources in the FRR plan would have cleared as economic supply. While the exact quantity of cleared supply in the BRA might have been slightly different had the Duke Energy Ohio FRR capacity been included in the BRA, the fact that the Duke Energy Ohio resources were economic implies that there would have been no material difference in either clearing prices or costs to BRA participants.

Q. WOULD RECOVERY OF DUKE ENERGY OHIO'S EMBEDDED COSTS BE DISCRIMINATORY OR RESULT IN ANY COMPETITIVE ADVANTAGE FOR DUKE ENERGY OHIO OVER OTHER RETAIL OR WHOLESALE SUPPLIERS?

A. No. Because the charge will be passed on to all customers, regardless what LSE provides their retail electric service, the recovery will not result in discriminatory treatment of any customers or suppliers. The non-bypassable charge also does not lead to any disadvantages for other suppliers relative to Duke Energy Ohio. Suppliers are on an equal footing in competing for retail customers, as all the deferred cost recovery will be passed on to all distribution customers, so no retail customer will gain an advantage by choosing Duke Energy Ohio over a competitive supplier. Likewise, the costs of capacity to competitive suppliers (charged by PJM) will be determined by the BRA clearing price for all suppliers, so no advantage is created in terms of cost of meeting resource requirements.

Q. DOES DEFERRED RECOVERY OF DUKE ENERGY OHIO'S EMBEDDED COSTS CREATE ANY COMPETITIVE ADVANTAGE FOR DUKE ENERGY OHIO'S NON-REGULATED AFFILIATE?

A. No. As stated in its Application, Duke Energy Ohio plans to transfer its legacy generation to it non-regulated affiliate, Duke Energy Commercial Asset Management, Inc. (DECAM). The Application notes, "that portion of the recovery attributable to the time period during which the assets are owned by the affiliate should then be passed through to such affiliate." However, transfer of a portion of recovery will in no way affect the operations or market-based incentives for the assets transferred to DECAM, since recovery is not dependent on future capacity or energy market outcomes, but only on ownership of the generation assets. Hence, DECAM should be expected to offer the assets into the forward capacity and energy markets based on its marginal costs, as would any other competitive market supplier. No advantage in the form of subsidized operating expenses or other variable costs will be provided to DECAM, so no competitive advantage is created. During the remainder of the FRR period, DECAM would simply be providing Duke Energy Ohio with capacity on a back-to-back basis so that Duke Energy Ohio can service its already-existing FRR obligations as part of its already-existing FRR resource plan.

III. CONCLUSION

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

Exhibit SWN-1

SCOTT W. NIEMANN

Director and Principal

EXPERIENCE

ESAI Power LLC

January 2013 - Present: Director and Principal

Charles River Associates

2011 – 2012: Vice President

2005 – 2010: Principal

2001 – 2004: Associate Principal

PA Consulting Group

2000 – 2001: Principal Consultant

Putnam, Hayes, and Bartlett (PHB Hagler Bailley)

1998 – 2000: Associate

EDUCATION

Ph.D. Economics, University of Wisconsin, 2001

M.S. Economics, University of Wisconsin, 1996

B.A. Mathematics, Political Science, Economics, University of Kansas, 1993

PROJECT EXPERIENCE

WHOLESALE ELECTRICITY MARKET ANALYSIS AND MODELING

- On behalf of companies involved in power marketing, electricity generation, and energy transmission and delivery, performed more than 100 analyses of energy prices, power plant performance, and generation asset values in North American wholesale energy markets. This work has involved contributing to the development of a suite of detailed models, including a GE MAPS model of the North American wholesale energy market, and managing numerous simulations of the Eastern and Western U.S. and Canadian electricity markets using this suite of models.

- Served as Independent Market Advisor in several electric power asset transactions. These engagements have involved due diligence support, preparation of Independent Market Advisor's report for the sale and/or financing process, presentations and teleconferences with investors, lenders, and debt rating agencies. Assets have included several Combined-Cycle facilities in the Northeast U.S. Regional Transmission Organizations, peaking facilities in various U.S. Markets, gas- and oil-fired steam electric plants, wind generation, and base load assets.

- Led the development of CRA's GE-MAPS modeling capabilities, including compilation and auditing of generation, load, fuel price, and transmission data, and incorporation of these data into an MS-ACCESS database and interface with the GE-MAPS model. Managed the model calibration refinement of model inputs, outputs, and post-processing to provide realistic commercial results.

- On behalf of Cape Wind Associates, conducted a study of the market impact of adding offshore wind in the ISO New England market. Assessed the effects of the Cape Wind project on wholesale power prices, consumer costs, airborne emissions, and fuel mix for the New England market. The study was used in support of a successful application to the Massachusetts Department of Public Utilities for approval of a power purchase agreement between Cape Wind and National Grid.

- Led a team evaluating the profitability and potential consumer benefits of a proposed transmission lines that would provide additional import capability into the Northeast US electricity markets.

- Provided on-going market forecasting and valuation of a merchant combined-cycle power plant in the Northeast U.S. and associated power purchase agreements. Analysis is used in the operational and strategic decision marking of senior management. Presented results to board of directors and public agencies.

- Assisted a merchant power provider with a successful bid as part of a public procurement process for long-term power supply. Support included market modeling and price forecasting, estimation of consumer benefits from construction of a new generating facility, presentations to and preparation of materials for counterparty regarding the market impacts of the contract, and strategic analysis for the pricing and structuring of the bid.

- On behalf of US Power Generating, LLC., conducted an analysis of the New York City capacity and energy markets to support the evaluation and successful acquisition of the Astoria generating portfolio. Prepared independent market assessment and forecast of financial performance to support the financing process.

- On behalf of a generation owner, estimated the impacts on power prices and the value of the company's portfolio of generation additions and repowering projects under consideration for the company's existing sites in the Northeast U.S.

- On behalf of a generation owner engaged in merger negotiations, prepared an assessment of the company's existing portfolio of assets and the markets where the assets are located. Assessment was used to guide the company's internal strategic discussions and provided to the counterparty as part of the negotiations.

- On behalf of a large U.S. utility, assessed the impacts on the value and operation of its assets of integrating its service area into a competitive, LMP-based market. The analysis examined a broad range of issues including the effects of constraints outside the utilities service area on LMPs within the area, mitigation of seams issues, impacts of the precise definition and implementation of constraints within market software on the congestion patterns affecting nodal prices in the utilities territory, and the ability to hedge congestion risks through an FTR portfolio.

- On behalf of the Vice President of Energy Management at Con Edison, conducted several studies related to the NYISO market, including:

    - Analysis of the impact of changes in a wheeling arrangement between Con Edison and PSE&G using a GE-MAPS model of the Northeast U.S. The analysis included comparison of location prices, transmission congestion, and generation patterns within the PJM and NYISO systems under a range of PJM-NYISO transfer scenarios. Evaluated various strategies for implementation of the wheeling arrangement in light of market rules, commitment and dispatch methodologies, and transmission constraints within PJM and the NYISO.

    - Evaluation of the impacts on locational prices, generation costs, and costs to retail consumers within both PJM and the NYISO of moving Rockland Electric load from the NYSIO to PJM.

    - Evaluation of benefits of potential transmission upgrades both within New York City and other parts of the NYISO system.

  - Analysis of the impacts on locational prices and costs to retail customers of generation and transmission outages within New York, generating capacity additions in various locations, and proposed retirement of existing units.

- On behalf of participants in auctions for financial transmission rights (FTRs) and Transmission Congestion Contract (TCCs), analyzed bidding strategies, historical and forecasted congestion patterns, impacts of changes in market rules on FTR values, and historical FTR and TCC auction outcomes.

RESOURCE ADEQUACY POLICY AND CAPACITY MARKETS

- Provided expert testimony (both written and live oral) on behalf of NRG as part of the Connecticut Department of Public Utility Control (DPUC) proceeding regarding procurement of energy and capacity awarded under the Connecticut Energy Independence Act. Testimony focused on the benefit evaluation approach implemented in the selection of winning projects.

- On behalf of numerous market participants, conducted independent market assessments of northeast ISO resource adequacy markets. Led the development of CRA's price forecasting models for ISO-NE Forward Capacity Market, NYISO UCAP market, and PJM RPM Market. Served as capacity market expert in numerous assignments to support capacity acquisitions, financing, transfer pricing, and strategic decision making.

- Led the analysis of the benefits of proposed new transmission line that would result from lower capacity prices and capacity procurement costs within a Northeast US market.

- On behalf of the Dayton Power and Light Company, provided expert testimony supporting CRA's forecast of PJM capacity prices under its RPM forward capacity market.

MARKET DESIGN

- Advised market participants during the Federal Energy Regulatory Commission (FERC) proceedings related to the design and implementation of the ISO-New England Forward Capacity Market (FCM), PJM Reliability Pricing Model (RPM), and New York ISO Installed Capacity (ICAP) Market.

- Provided expert testimony on behalf of Pepco Energy Services to support a complaint before FERC regarding RPM market rules for performance incentives and penalties.

- Served as Project Manager for a CRA team engaged by ESB National Grid, the Irish system operator, to assist in the design of a competitive wholesale market for Ireland and develop the rules for the market. As Project Manager, coordinated team staffing and deliverables schedule, working on-site in Dublin. Led or participated in meetings with CRA team and client staff to develop straw man proposals for market design aspects. Drafted and presented discussion papers outlining aspects of the proposed design.

NATURAL GAS

- Led analytical efforts to estimate the gas demands related to steam and electric generation for a New York utility, examining a range of scenarios based on the relative prices of natural gas and other fuels, electricity demand, and the future mix of generating technology and fuel options.

- On behalf of the New York Research and Development Authority, managed a team to develop an integrated natural gas and electric modeling system to evaluate the adequacy of the gas delivery system for meeting the future demands of electric generators. Led electricity modeling efforts related to the estimation of fuel demands among electric generators in New York and neighboring regions, accounting for transmission constraints, gas delivery constraints, and fuel switching by generations.

- On behalf of a large power generating and trading organization, acted as independent market expert supporting antitrust approval of a natural gas asset acquisition. Led an evaluation of potential market power concerns stemming from the acquisition of natural gas transportation and storage assets and presented analysis to the Department of Justice in support of the company's successful application for agency approval under the Hart Scott Rodino Act.

COST-BENEFIT ANALYSIS

- As part of a team working on behalf of the New York City Economic Development Corporation, served as a market expert for an evaluation of potential transmission projects for New York State and New York City. The study evaluated the market impact of several potential transmission projects and generation project alternatives, assessing each project under a range of production costs and consumer cost benefits metrics.

- On behalf of the New York City Economic Development Corporation, provided expert testimony before the New York State Public Service Commission as part of the Article VII hearing for the Hudson Transmission Partners transmission project under development between New York City and New Jersey. Testimony focused on market impact and cost-benefit analysis of the project.

- On behalf of Dominion Virginia Power, led analytical efforts related to wholesale power markets in an assessment of the costs and benefits of integration of Dominion into the PJM market.

- On behalf of a U.S. utility, conducted an assessment of the power market related costs and benefits of adding a base load coal plant with the utility's service area.

- On behalf of various U.S. clients, contributed to studies of the costs and benefits of forming Regional Transmission Organizations and implementing economic congestion management and LMP in place of physical congestion management. Specifically, the studies address the elimination or alleviation of seams issues between markets, FTR allocations, formation of regional load prices in markets with nodal prices for generators, and impacts of market changes on retail electric rates.

- Evaluated benefits of potential transmission upgrades in the northeastern U.S. and Canada. The analysis used a GE MAPS model of the Eastern interconnection to measure the change in energy prices, and consumer and producer surplus in the Great Lakes Region.

- Evaluated the costs and benefits of adding new transmission lines at various locations within the Northeast U.S.

- Evaluated the economic and environmental impact on a North American regional energy market of retiring coal-fired generation. The analysis involved estimation of the resulting changes in energy prices, power plant emissions, costs to consumers, and financial performance of generation assets.

MARKET POWER

- Led analytical efforts supporting CRA expert testimony before the Federal Energy Regulatory Commission regarding the manipulation of electric power prices in the Pacific Northwest during the California Energy Crisis. Analysis addressed the reasonableness of a wholesale power contract in light of spot and forward market prices and the ability of power markets and traders to influence those prices.

- Studied generator bidding behavior in northeastern electricity markets and the impacts of market power mitigation measures.

- On behalf of clients in the wholesale electric power and natural gas industries involved in mergers or assets sales, assessed market power concerns under the FERC's Appendix A Merger Guidelines for transactions in several U.S. regions, including NYISO, ISO-NE, PJM, SERC, ECAR, SPP, ERCOT, and WECC.

OTHER ENERGY LITIGATION

- Conducted analyses supporting CRA expert testimony in commercial litigation and FERC proceedings, including:

    - Wholesale power contract disputes.

    - Disputes over transmission rights.

    - Market design and market power mitigation issues.

    - Allegations of market power abuses.

    - Damages analysis related to generating unit outages.

- Provided expert testimony regarding expected electricity prices, generator unit operations, and the corresponding value of transmission credits held by the owners of a merchant power plant in the Southeast U.S.

OTHER ENERGY PROJECTS

- On behalf of a generation owner selling in the ISO-NE market, conducted an audit of payments for out-of-merit generation and associated uplift payments and production costs to identify recoverable costs and potential underpayments by the ISO.

- As part of a team working for an electric transmission and distribution utility, designed and conducted the econometric analysis for a study of customer value of service reliability. The study involved design and implementation of a survey and econometric analysis of the resulting data to measure residential and commercial customers' outage costs and willingness-to-pay to avoid various outage scenarios.

ENVIRONMENTAL LITIGATION

- On behalf of a municipal utility involved in litigation involving alleged natural resource damage, assisted in estimating the economic value of damaged resources. Project work included review of documents, collection of data, formulation of an economic framework for measuring damages, and support of an academic expert witness.

- On behalf of a Middle-Eastern country making a claim for environmental damages arising out of the 1990 Gulf War, assisted in the assessment and valuation of potentially recoverable economic damages. Conducted substantial in-country research and developed techniques to value changes in health and environmental conditions. The confidential assessment was submitted to the United Nations Compensation Commission.

- For a property value dispute in the western United States, evaluated alternative valuations of environmentally impaired commercial real estate. The project involved review and critique of a survey used to elicit willingness-to-pay and evaluation of alternative measures based on market transactions.

- For a residential property value dispute, conducted an econometric analysis of survey-based willingness-to-pay measures for changes in groundwater quality and associated health risks. The effort involved analysis of data from several surveys, each with a different design and format, to assess potential biases in the survey responses and determine the effects of various demographic characteristics.

- For companies engaged in settlement discussions and litigation regarding environmental insurance coverage claims, estimated the cleanup costs and potential natural resources and property damage liability at hazardous waste sites. The work involved development of detailed, site-specific estimates using probabilistic assessment methods to determine the expected present value and distribution of future costs, which reflect technical and regulatory uncertainty.

OTHER COMMERCIAL LITIGATION

- For a major corporation involved in an intellectual property and antitrust dispute, performed analyses of market share, production capacity, output prices, and production costs. Assisted in the estimation of alternative measures of economic damages using market share, lost profits, and stock market valuation methods. Provided support in the preparation of expert reports.

- For a privately held company involved in a tax dispute, evaluated cash retention strategies of publicly and privately held firms. The analysis involved reviewing academic literature and evaluating implications of finance theory for the decisions of different types of firms in various industries.

Testimony

Date	Case	Venue
August 2011	Astoria Generating Company, L.P and TC Ravenswood, LLC v. New York Independent System Operator, Inc.	U.S. Federal Energy Regulatory Commission, Docket No. EL11-50-000
March 2010	Article VII Application of Hudson Transmission Partners, LLC	New York Public Service Commission Case No. 08-T-0034
February 2009	Stipulation and Recommendation of Dayton Power and Light Company regarding Standard Service Offer Rate Plan Approval	Public Utilities Commission of Ohio, Case No. 08-1094-EL-SSO, 08-1095-EL-ATA, 08-1096-EL-AAM, 08-1097-EL-UNC
September 2008	Application of Dayton Power and Light Company for Standard Service Offer Rate Plan Approval	Public Utilities Commission of Ohio, Case No. 08-1094-EL-SSO
April 2008	Pepco Energy Services, Inc. v. PJM Interconnection, L.L.C.	U.S. Federal Energy Regulatory Commission, Docket No. EL08-58-000
July 2007	Hearing Regarding Winners of Connecticut Energy Independence Act RFP, on behalf of NRG Energy	Connecticut Department of Public Utility Control, Docket 07-04-24
December 2004	Mirant Corporation, et al, v. Kinder Morgan	District Court of the State of Texas, Case No 03-46590-11