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Via E-FILE

September 26, 2014

Public Utilities Commission of Ohio
PUCO Docketing
180 E. Broad Street, 10th Floor
Columbus, Ohio 43215

In re: Case No. 14-841-EL-SSO and 14-842-EL-ATA

Dear Sir/Madam:

Please find attached the PUBLIC VERSION of the DIRECT TESTIMONY AND EXHIBITS OF ALAN TAYLOR and STEPHEN J. BARON on behalf of the OHIO ENERGY GROUP e-filed today in the above-referenced matters.

The original and three (3) copies of the CONFIDENTIAL pages to be filed under seal will follow by overnight mail.

Copies have been served on all parties on the attached certificate of service. Please place this document of file.

Respectfully yours,

David F. Boehm, Esq.
Michael L. Kurtz, Esq.
Jody Kyler Cohn, Esq.
BOEHM, KURTZ & LOWRY

MLKkew
Encl.
Cc: Certificate of Service

CERTIFICATE OF SERVICE

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BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Duke Energy Ohio for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan, Accounting Modifications and Tariffs for Generation Service.	))))))))	**Case No. 14-841-EL-SSO**
In the Matter of the Application of Duke Energy Ohio for Authority to Amend its Certified Supplier Tariff, P.U.C.O. No. 20.	)))	**Case No. 14-842-EL-ATA**

DIRECT TESTIMONY

OF

ALAN S. TAYLOR

PUBLIC VERSION

ON BEHALF OF

THE OHIO ENERGY GROUP

SEDWAY CONSULTING, INC.
BOULDER, COLORADO

September 2014

BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Duke Energy Ohio for Authority to Establish a Standard Service Offer Pursuant to 4928.143, Revised Code, in the Form of an Electric Security Plan, Accounting Modifications and Tariffs for Generation Service.	)	**Case No. 14-841-EL-SSO**
In the Matter of the Application of Duke Energy Ohio for Authority to Amend its Certified Supplier Tariff, P.U.C.O. No. 20.	)	**Case No. 14-842-EL-ATA**

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I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Alan S. Taylor. My business address is Sedway Consulting, Inc. ("Sedway Consulting"), 821 15th Street, Boulder, Colorado 80302.

Q. What is your occupation and by who are you employed?

A. I am the President of Sedway Consulting, a firm that specializes in providing independent evaluation services to utilities around the country in procuring and negotiating contracts for new power supplies and hedging products.

Q. Please describe your education and professional experience.

A. I earned a Bachelor of Science Degree in energy engineering from the Massachusetts Institute of Technology and a Masters of Business Administration from the Haas School of Business at the University of California, Berkeley, where I specialized in corporate finance.

I have worked in the utility planning and operations area for 29 years, predominantly as a consultant specializing in integrated resource planning, competitive bidding analysis, utility industry restructuring, market price forecasting, and asset valuation. I have testified before state commissions in proceedings involving resource solicitations, environmental surcharges, fuel adjustment clauses, and other rate riders.

I began my career at Baltimore Gas & Electric Company (BG&E), where I performed efficiency and environmental compliance testing on the utility system's power plants. I subsequently worked for five years as a senior consultant at Energy Management Associates (EMA, subsequently New Energy Associates and now a division of Ventyx), training and assisting over two dozen utilities in their use of EMA's operational and strategic planning models, PROMOD III and PROSCREEN II. During my graduate studies, I was employed by Pacific Gas & Electric Company (PG&E), where I analyzed the utility's proposed demand side management (DSM) incentive ratemaking mechanism, and by Lawrence Berkeley Laboratory (LBL), where I evaluated utility regulatory policies surrounding the development of brownfield generation sites.

Subsequently, I worked at PHB Hagler Bailly (and its predecessor firms) for ten years, serving ultimately as a vice president in the firm's Global Economic Business Services practice and then as a senior member of the Wholesale Energy Markets practice of PA Consulting Group when that firm acquired PHB Hagler Bailly in 2000. In 2001, I founded Sedway Consulting, Inc. and have continued to specialize in economic analyses associated with electricity wholesale markets. I have been the project lead in overseeing dozens of conventional and renewable resource solicitations and have evaluated thousands of proposals for power supply contracts. In addition, I have monitored and evaluated offers in hedging product solicitations and auctions where utility clients were seeking fixed-for-floating swaps, call options, or other hedging products to stabilize their customers' exposure to electric or natural gas market fluctuations.

In recent years, I have been very active in California – a state that took a similar path to the one Ohio has chosen, requiring in the 1990s that investor-owned utilities divest most of their generation and rely on an energy market exchange for their primary power supplies. As I describe later, this led to disastrous results, ultimately causing the state to change course and adopt stabilizing policies that I have helped implement and which may be applicable and valuable for Ohio.

My resume is attached as Taylor Exhibit __ (AST-1).

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of The Ohio Energy Group ("OEG"), a group of large industrial customers of Duke Energy Ohio ("the Company").

Q. Have you previously testified before the Public Utilities Commission of Ohio?

A. Yes, in fact, I testified earlier this year in a similar Electric Security Plan ("ESP") proceeding involving an application by AEP-Ohio.

Q. What is the purpose of your testimony?

A. I am supporting the concept of a Price Stabilization Rider associated with the net benefits of Duke Energy Ohio's portion of the Ohio Valley Electric Corporation

("OVEC") power plants that is discussed in Company Witness William Don Wathen Jr.'s direct testimony. I think that such a rider would have the effect of stabilizing or providing certainty regarding retail electric service rates for the Company's customers. However, there are modifications to the Price Stabilization Rider that I am proposing that could enhance its stabilizing nature and provide benefits over a more appropriate time frame.

Q. Please summarize your testimony.

A. My testimony is organized into three sections. In the first section, I provide some background on rate stabilizing products and the deregulatory path that California took. I believe that price stability is beneficial for most utility customers and that a balanced supply portfolio (where market or marginal cost pricing is hedged with fixed-price or countercyclical products) can stabilize customer electricity prices that might otherwise be prone to significant fluctuations.

In the second section, I provide an overview of the OVEC assets and the associated Price Stabilization Rider that is being proposed by Duke Energy Ohio. While the current costs of the OVEC power supplies are greater than the market benefits of such supplies, I think that this is likely to change before long, given that a significant amount of coal-fired generation in the PJM Interconnection system ("PJM") is retiring and market supplies for energy and capacity are tightening. This is likely to drive up market prices and increase the benefits associated with the OVEC generation. Also, given that the OVEC assets have a portion of their costs that are fixed and the remainder is based on low-cost coal at a relatively fixed-price, this OVEC generation is likely to provide countercyclical benefits. As energy market prices rise (either because of severe weather conditions or generating capacity scarcity), the OVEC plants will be dispatched more and their all-in $/MWh price of generation will decline. Thus, customers with a balanced, blended portfolio of market purchases and OVEC generation would experience offsetting influences that would stabilize their electricity prices.

In the third section, I propose modifications to Duke Energy Ohio's Price Stabilization Rider. First, I recommend that it be established as a non-cancellable rider that should be formally instituted for a reasonable period of time – longer than the ESP that is the subject of the current proceeding but shorter than the remaining lives of the OVEC generating assets. Duke Energy Ohio's forecasts indicate that the costs of the OVEC generation are likely to exceed its energy and capacity market benefits for the next several years. As discussed above, this is likely to reverse (and indeed is shown to do so in Duke Energy Ohio's forecasts) in the near future, with the OVEC benefits expected to exceed costs as we near the end of this decade. I think that Duke Energy Ohio's customers should be assured of the longer-term net benefits of the rider by locking it in for a period that spans the next several ESPs. Also, I propose a levelization approach that would flatten the Price Stabilization Rider and remove what is otherwise likely to be a front-loaded cost to Duke Energy Ohio's customers under the current plan. The proposed levelization approach would advance the long-term benefits and bring the rider closer to a market-neutral hedge in all years. Because the levelization approach would involve Duke Energy Ohio advancing future savings to its customers in the current year, there would be a regulatory balancing account included in the arithmetic of the rider whereby Duke Energy Ohio would be made financially whole by earning its weighted average cost of capital on the cumulative balance in the account. Thus, the proposed levelized approach is revenue-neutral to Duke Energy Ohio. Finally, it is important to recognize that because the modified Price Stabilization Rider is a financial instrument, it does not change the physical amount of energy or capacity that a shopping customer must buy for its own account. Likewise, it does not change the amount of energy or capacity that must be supplied in the standard service offer ("SSO") auctions for non-shopping customers. Therefore, the modified Price Stabilization Rider maintains the benefits of a competitive market, while adding needed price stability.

II. THE BENEFITS OF HEDGES AND CALIFORNIA'S EXPERIENCE

Q. Please describe what you mean by a hedge.

A. A hedge is a simply a transaction that helps offset the consequences of circumstances that are outside of one's control. In our regular lives, insurance is an example of a hedge. Most people insure their homes so that a loss (such as a fire or flood) will be offset with payments that will help the household financially recover should there be such a bad turn of events. If there never is a fire or flood, so much the better; even though the insurance ends up being a net outflow of money (in the form of insurance premiums), the owners of the house benefit from having the peace of mind that the insurance provides. In the context of this Duke Energy Ohio proceeding, the OVEC hedge can provide a similar form of insurance against high market prices. Even if those high market prices do not materialize, having the OVEC hedge as part of Duke Energy Ohio's customer supply portfolio can provide the peace of mind and avoid the concerns associated with customers being 100% reliant on the marginal-cost wholesale electricity markets.

Q. Do you think that 100% reliance on the marginal-cost wholesale electricity markets is wise?

A. Everyone has their own level of risk tolerance, but no, I think that most customers benefit from rate stability and that 100% reliance on a marginal-cost electricity market is unwise. Perhaps it has looked like an attractive bet in recent years in the PJM energy market, but it represents an unbalanced supply portfolio that can be vulnerable to significant price spikes. The relative calm in the PJM markets in the 2009-2013 timeframe may be coming to an end. This past winter's "polar vortex" that blanketed much of the country with colder-than-normal weather certainly moved prices up significantly. To be clear, I think that marginal-cost or spot energy markets can be a valuable component of a utility's or end user's supply portfolio, but it should not be all of it. State-regulated hedging products or fixed-cost supplies should be part of the portfolio as well. A balanced supply portfolio can help a utility weather the economic storms that invariably roil markets from time to time and thereby help the utility stabilize its customers' electricity prices.

Q. Please describe common electricity and natural gas hedging products that you have seen employed to stabilize customer electricity prices.

A. I have overseen solicitations for hedging products such as fixed-for-floating swaps and call options. Both can be used to protect against unexpected increases in natural gas or electricity market prices. Fixed-for-floating swaps in the natural gas sector (and in the electricity sector) are contracts where a seller is agreeing to financially settle with a buyer each month over the term of the contract for any differences (positive or negative) between a fixed price of natural gas (or electricity) and the actual market price in that month. Utilities use this type of hedging product to lock in the effective price of some portion of their monthly natural gas purchases. This keeps them from being completely exposed to dramatic fluctuations in the price of natural gas. Such a hedge is financially beneficial for the buyer during periods when natural gas prices move up quickly. Conversely, if natural gas prices decline, the buyer's purchase of the hedge can look like the wrong decision. In either scenario, though, fixed-for-floating swaps that cover some portion of a utility's likely gas quantity purchases provide for greater stability of procurement costs than without them – i.e., where the utility is 100% exposed to the market. The same type of hedge in the electricity markets has the same stabilizing influence on a utility's electricity procurement costs and/or trading operations. For example, I have overseen solicitations where the utility has entertained fixed-for-floating offers from Qualifying Facility ("QF") owners who are willing to propose a fixed sales price for their electricity versus the fluctuating formulaic prices that are in their QF contracts.

Q. You mentioned call options. Please describe those.

A. A call option is a hedging product where the seller guarantees to sell the product (e.g., natural gas, electricity, a corporation's publically-traded stock) to the buyer at a set price – the strike price. Thus, when market prices move above that strike price, the buyer's costs are capped. Call options can provide valuable protection from skyrocketing prices. It does not matter how high market prices go, the buyer can procure the quantity of the product covered by the call option at the set strike price. Of course, the call option comes at a cost – namely the option premium that the buyer must pay to acquire the call option. In a sense, utility power purchase agreements ("PPAs") are essentially call options, where monthly capacity payments are made to power plant owner/operators in return for the ability to purchase energy from their facilities at a fixed price or, in tolling PPAs, at a guaranteed heat rate. Whether it is through financially-settled call options or through PPAs, these products provide utilities with protection from high market prices and help stabilize their energy procurement costs. I have seen these products used effectively in California (and elsewhere) to stabilize prices, ensure system reliability, and prevent the problems that had previously driven that state's electricity sector into crisis when it was overly exposed to market prices.

Q. Please describe what happened in California.

A. California pursued a similar path to Ohio in that the state's investor-owned utilities ("IOUs") were required to divest most of their generation in the 1990s and buy their customers' energy requirements from a state power exchange. The expectation was that supply shortages would drive up market prices and consequently encourage merchant developers to construct new generation facilities, thereby eliminating the supply shortage and bringing prices back down. However, power plant development takes years and cannot respond quickly to high market prices. In 2000 and 2001, insufficient generation capacity (in addition to alleged market manipulation on the part of market traders such as Enron) led to rolling brown-outs and rapidly increasing market prices that pushed the state's IOUs to the financial brink (and over it, in the case of Pacific Gas & Electric, which declared bankruptcy). In reaction to this crisis, the state legislature passed California Assembly Bill 52 ("AB52") which made the IOUs responsible for soliciting and procuring contracts for new generation facilities that would meet capacity targets authorized by the California Public Utilities Commission ("CPUC"). AB52 gave assurance that the IOUs would be allowed to recover the full cost of appropriately-procured contracts and provided for the sharing of the net capacity costs of these contracts among all benefitting customers, including those in the utility's area that had left the utility for alternative suppliers.

Q. So the IOUs became responsible for signing contracts that promoted the development of new generation in a timely fashion to ensure system reliability and stabilize prices?

A. Yes. There are biennial Long Term Procurement Plan ("LTPP") proceedings that set the authorized procurement targets for each of the IOUs, after which the utilities issue requests for proposals ("RFPs"), evaluate responses, and negotiate contracts for the best resources. This has resulted in a hybrid market, where new capacity is brought on-line under long-term contracts from these RFPs and existing capacity is bid into annual utility solicitations for compliance with each utility's near-term capacity requirements.

Q. So the utilities' customers have received rate stabilizing benefits from these new generation contracts?

A. Yes, both in the form of the power plant call option benefits I discussed above and in the form of tamer energy and capacity markets where adequate targeted reserve margins ensure a reliable system and avoid prolonged skyrocketing prices. The utilities' customers are hedged with these PPAs and therefore are not 100% exposed to marginal-cost market prices. Effectively, their supply portfolio is a balanced blend of market purchases and generation from PPAs.

Q. And in a similar fashion, an OVEC Price Stabilization Rider could be used to stabilize the rates of Duke Energy Ohio's customers and protect them from being overly exposed to the energy market?

A. Exactly.

III. DESCRIPTION OF OVEC SUPPLY RESOURCE AND DUKE ENERGY OHIO'S PROPOSED PRICE STABILIZATION RIDER

Q. Please describe the OVEC supply resource.

A. The Ohio Valley Electric Corporation (OVEC), of which Duke Energy Ohio is a Sponsoring Company, has 11 coal-fired generating units – five at Kyger Creek in Gallipolis, Ohio with a combined nameplate capacity of approximately 1,086 MW, and six at Clifty Creek in Madison, Indiana with a combined nameplate capacity of approximately 1,304 MW. These plants were initially developed to provide electricity to the U.S. government's uranium enrichment operations, with some surplus going to the Sponsoring Companies. However, the U.S. government terminated the supply agreement in 2003. Thus, each Sponsoring Company now receives its entire portion of OVEC capacity and generation for its own supply portfolio. Duke Energy Ohio has entitlement to a 9% share of OVEC. Duke Energy Ohio's witness William Don Wathen Jr. introduced testimony with a proposal to implement a Price Stabilization Rider that would pass through to its customers the net benefits (be they positive or negative) of the OVEC resources for the duration of Duke Energy Ohio's entitlement.

Q. Do you think that the Price Stabilization Rider proposed by Mr. Wathen would be good for Duke Energy Ohio's customers?

A. In concept, yes, but I think that the duration of Duke Energy Ohio's proposed rider may be too indefinite or long of a period, thereby exposing the Company's customers to long-term risks. Also, at the same time, I believe that the rider should be instituted for a defined period of time, whereby both the Company and its customers would be bound to the hedging arrangement and it could not be terminated by either side for one or the other's advantage during this defined period. That is the essence of a hedge, and neither the Company nor its customers should be able to move in or out of the OVEC hedge at will. Instead, it should represent a bilateral commitment.

Q. Before turning to the defined time period issue, why do you think that the OVEC Price Stabilization Rider would be good – in concept – for Duke Energy Ohio's customers?

A. I think that OVEC's generation represents a stable source of power from facilities that have been recently upgraded with pollution control equipment that will allow them to comply with the upcoming Mercury and Air Toxics Standards ("MATS"). It is my understanding that no significant capital expenditures are expected over the next decade. The forecast of demand charges is relatively flat. The cost of coal is likely to be stable – particularly with the retirement of a lot of other coal units in the Midwest putting downward pressure on coal prices. Also, those coal plant retirements will put upward pressure on the capacity and energy market prices; so I think that OVEC's all-in generation costs are likely to be at or below market prices in the near future.

Q. What do you mean by all-in generation costs?

A. I am simply referring to the combined demand charges and generation costs, as calculated on a $/MWh basis (with the energy and capacity market prices similarly combined and represented on a $/MWh basis). It is important to note that with high energy market prices, OVEC's plants will be called on for more generation in more hours than in low energy market price situations. Because this additional generation is coal-based and is already very competitively priced relative to current energy market prices, it will cause the all-in $/MWh to decline with higher levels of generation. Also, it means that the volume of generation associated with the OVEC hedge will increase under the conditions when one would most want the additional generation (i.e., when market prices are high) and decrease when one would not want the generation (i.e., when market prices are low). This is in contrast to fixed-quantity hedges that are sometimes traded in electricity markets and is an added benefit of the OVEC hedge.

Q. So in high-market price circumstances, this would result in more OVEC generation being allocated to Duke Energy Ohio's customers?

A. In the context of the Price Stabilization Rider's financial settlement, yes; but it is important to recognize that the Price Stabilization Rider is a financial instrument and does not change the physical energy and capacity obligations or transactions in Ohio's deregulated market.

Q. So the Price Stabilization Rider would not have an effect on the physical quantities associated with the Ohio competitive market processes?

A. Correct. It would not change what a shopping customer has to buy for its own account and would not affect the SSO auction for non-shoppers. The OVEC hedge should have no effect on Competitive Retail Electric Suppliers ("CRES") providers. It maintains the benefits of a competitive market, while adding needed price stability. The OVEC hedge would provide rate stabilizing benefits for Duke Energy Ohio's customers while having no adverse effect on the market.

Q. When do you think that OVEC's all-in costs are likely to be at or below market prices?

A. I do not know, but Duke Energy Ohio's forecast from a January 2014 analysis showed that OVEC's combined demand and energy costs are expected to be above market prices in the next several years. Specifically, the OVEC net benefits are expected to be negative (i.e., where market prices are less than OVEC costs) [redacted] but positive in [redacted] and in all years thereafter. These net benefits are depicted in Confidential Taylor Exhibit__(AST-2) which is a summary of information extracted from Duke Energy Ohio's OEG-DR-01-001_Attachment_HIGH CONF interrogatory response. By "net benefits," I am referring to the amount that the energy and capacity revenues associated with Duke Energy Ohio's portion of the OVEC assets exceed Duke Energy Ohio's portion of the OVEC costs. The energy and capacity revenues represent what Duke Energy Ohio expects it would receive from selling its portion of the OVEC generation into the PJM energy market and its portion of the OVEC capacity into the PJM Reliability Pricing Model ("RPM") process. The OVEC costs are Duke Energy Ohio's portion of the OVEC Demand Charges plus OVEC generation energy costs. When these net benefits are negative, they translate into a charge that would increase customer bills. When positive, they would translate into a credit that would reduce the customer bills.

Q. **So by Duke Energy Ohio's January 2014 forecast and analysis, it appears that much of the OVEC benefits (when net benefits are expected to be positive) will occur after the upcoming ESP?**

A. Yes; and while it may be Duke Energy Ohio's intention to continue the Price Stabilization Rider through subsequent ESPs and the end of its OVEC entitlement, I think it would be appropriate to lock in the Price Stabilization Rider for a reasonable, defined period of time so that the Company cannot change its mind and drop the rider when the net benefits turn positive; if customers are going to be exposed to the early years of negative net benefits, they should be assured of the opportunity to benefit from the expected OVEC positive net benefits in future years.

Q. **Do you think that Duke Energy Ohio's January 2014 forecast and analysis is reasonable?**

A. I think that it is a conservative outlook for the OVEC net benefits. The long-term values were developed before the full impact of this last winter's "polar vortex" was experienced. In addition, earlier this year, I participated in a similar Ohio regulatory proceeding involving AEP-Ohio's ESP III filing. That utility also owns a portion of the OVEC assets and provided a forecast of the expected costs and revenues from its entitlement. That forecast – which I still think was on the conservative side – showed greater net benefits than Duke Energy Ohio's forecast. Both forecasts included estimates of PJM RPM future capacity prices that, based on my experience in power supply procurement and contracting, appear to be too low to attract the development of new generation in the state. I believe that the PJM RPM capacity prices are likely to trend higher than either of these utilities' forecasts. Given the amount of capacity that is being retired in PJM, I think that will provide upward pressure on capacity prices and will increase the net benefits of the OVEC hedge beyond what may have been forecasted in these ESP proceedings.

Q. But don't you agree that Ohio has a well-functioning competitive market, as evidenced by the considerable number of CRES providers?

A. I do not think that the number of CRES providers is the best metric for gauging the success or strength of Ohio's competitive wholesale market. Instead, one needs to see adequate wholesale market pricing and the consequent development of new generation projects (and/or demand-side investments) that result in long-term reliable service for the state's customers.

IV. PROPOSED MODIFIED PRICE STABILIZATION RIDER

Q. So your proposed modified Price Stabilization Rider would apply to a specific span of years?

A. Yes. I am proposing a rider that would start in June 2015 at the beginning of the upcoming ESP and continue through and beyond the next two ESPs until the end of calendar year 2024 – approximately nine and half years. This time frame would be consistent with the PPAs and tolling-types of hedge products that I have seen procured elsewhere in the country. Also, this time frame would increase the likelihood that cumulative OVEC net benefits and associated rider would be rate neutral (i.e., close to zero). Based on the results depicted in Taylor Exhibit__(AST-2), Duke Energy Ohio's January 2014 analysis projected that the expected OVEC net benefits over the eight and half years from June, 2015 through the end of calendar year 2023 would be approximately [redacted] or about [redacted]/year. Note that this time frame for projected benefits is one year less than the time frame for the rider. This is because there would be a true-up of actual costs at the end of each calendar year (described below) that would translate into a final year's rider in 2024 for trued-up expenses from the end of 2023.

Q. Would extending the time period for the Price Stabilization Rider beyond 2024 yield potentially greater benefits?

A. Possibly, but going too far into the future may expose Duke Energy Ohio's customers to unknown risks (such as eventual decommissioning costs and higher-than-expected CO2 costs, should federal or state legislation be enacted in this area). As I will discuss later, the concept behind the Price Stabilization Rider is that both Duke Energy Ohio and its participating customers would be bound to the nine and a half year term. There would be no opportunity for jumping in or jumping out in either party's case.

Q. You mentioned in your testimony summary that the Price Stabilization Rider would be levelized. Please describe this process.

A. The Price Stabilization Rider would be premised on Duke Energy Ohio's approximately [redacted] of OVEC net benefits over the nine and a half year period. That net benefit total would be divided by the number of years to arrive at an annual value of [redacted]/year as depicted in Taylor Exhibit__(AST-3), with an appropriate partial-year adjustment for 2015. That average annual net benefit would be the starting foundation for the annual Price Stabilization Rider. However, because the forecasted OVEC net benefits are expected to be negative in the first several years, then increasing into positive values later, a flat stream of payments to Duke Energy Ohio's customers will entail the utility pre-paying future savings. Duke Energy Ohio will need to be compensated for, in effect, loaning money to its customers in the early years of the rider. Thus, a regulatory balancing account would be established to track Duke Energy Ohio's cumulative net pre-payments and allow the utility to earn a return on that balance at its after-tax weighted average cost of capital. Incidentally, the converse would be true as well. If in any year the regulatory balancing account was negative (i.e., the utility's customers were lending money to Duke Energy Ohio), the same Duke Energy Ohio after-tax weighted average cost of capital would be used to determine the return that should be conveyed to the customers. In any case, a levelized return on this regulatory balancing account would be initially calculated, based on the Duke Energy Ohio foundational forecast of OVEC net costs. This levelized return would have the same value in each year, and its net present value would be the same as the net present value for the non-levelized return. Taylor Exhibit__(AST-3) shows this levelized return to be approximately [redacted]/year. The combination of the levelized return and the levelized net benefits would yield the initial Price Stabilization Rider of [redacted]/year (= [redacted] + [redacted]), with the positive value reflecting a rider cost/adder. This first year rider would be adjusted for the 2015 partial year and for a Duke Energy Ohio 10% participation rate, discussed below.

Q. But this is all based on a forecast of OVEC net benefits. Forecasts are never perfect. What happens when the actual net benefits are different than the forecast?

A. At the end of each year or quarter, there would be a true-up process. Actual OVEC net benefits for the year or quarter that just ended (and perhaps any known capacity revenues or budgets for the prospective year or quarter) would be compared to that year's or quarter's forecasted net benefits. The difference would be amortized over the following three years in a layering process depicted in Taylor Exhibit__(AST-3). Note that Lines 11 and 12 on Page 2 of 3 of that exhibit depict a specific scenario of "actual" OVEC net benefits and their differences from the forecast. The exhibit demonstrates how this scenario of specific OVEC net benefit differences would be trued-up and is illustrative only. Toward the end of the Price Stabilization Rider period (e.g., 2022 and 2023) – where there are not three years left in the rider period – the differences would be amortized over the remaining years or year. There would also be a true-up to the regulatory balancing account – in effect, a separate regulatory balancing account that would only track the returns on the cumulative net loans (positive or negative) associated with the annual <u>differences</u> between the actual OVEC net benefits and the forecasted ones. This is because the original levelized return already accounted for the returns associated with the forecasted net benefits. In the end, the two true-up components – 3-year amortized differences and trued-up return would be added to the original levelized Price Stabilization Rider.

Q. Would that be the rider for Duke Energy Ohio's customers?

A. Almost. There is one final step depicted in Taylor Exhibit__(AST-3). In order to provide incentives for Duke Energy Ohio to keep OVEC costs as low as possible and revenues from OVEC energy and capacity as high as possible, at least 10% of the rider would be allocated to the utility (i.e., its shareholders). The remainder would be put on Duke Energy Ohio's customer bills. This is expected to fluctuate (in a countercyclical and beneficial fashion) between being a credit or an adder.

Q. Would all Duke Energy Ohio customers get the Price Stabilization Rider?

A. There may be large industrial customers who would want to self-insure. These firms may have corporate finance departments that already deal with commodity, interest rate, or currency exchange rate hedges. Customers who can self-insure should have that option. Thus, I propose that any customer with more than 10 MW of load per single site should be given the chance to self-insure and not participate in the OVEC hedge. This would be a one-time election at the very beginning. Such customers would either be in or out of the hedge for the entire nine and a half years. There would be no allowance for moving in or out after the start of the OVEC hedge. The percent of load for any customers who chose not to participate would be added to Duke Energy Ohio's 10%. Thus, the rest of the customer base would not be affected (either positively or negatively) by any self-insurance decisions on the part of large customers.

Q. To what extent does the proposed Price Stabilization Rider hinge on the forecast of OVEC net benefits? To reiterate the earlier concern, isn't the rider flawed if the forecast is wrong?

A. While it is true that the Price Stabilization Rider is based on Duke Energy Ohio's January 2014 forecast of 2015-2023 OVEC net benefits, the forecast itself is largely irrelevant to the Price Stabilization Rider because the rider is self-correcting and is trued-up with actual OVEC costs and benefits. The forecast provides a "best guess" and helps start the Price Stabilization Rider at the right level; but the forecast need not be anything more than a ballpark approximation. Of course, the better the forecast, the more stable the rider's baseline – but even that baseline is an average over more than eight years and thus represents an annualized estimate where the forecast's year-to-year values have been smoothed out. In addition, forecasts aside, it is important to remember that the rider will always move from its baseline from quarter to quarter and year to year in providing the counter-cyclical benefits of dampening price swings in market prices as described earlier.

Q. Does this complete your testimony?

A. Yes.

AFFIDAVIT

STATE OF COLORADO)

COUNTY OF BOULDER)

ALAN S. TAYLOR, being duly sworn, deposes and states: that the attached is his sworn testimony and that the statements contained are true and correct to the best of his knowledge, information and belief.

Alan S. Taylor

Sworn to and subscribed before me on this 24th day of September, 2014.

Notary Public

BENJAMIN LEE HARRIS
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20124008759
MY COMMISSION EXPIRES 2/14/2016

BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Duke Energy Ohio for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan, Accounting Modifications and Tariffs for Generation Service.	)	**Case No. 14-841-EL-SSO**
In the Matter of the Application of Duke Energy Ohio for Authority to Amend its Certified Supplier Tariff, P.U.C.O. No. 20.	)	**Case No. 14-842-EL-ATA**

EXHIBITS

OF

ALAN S. TAYLOR

ON BEHALF OF

THE OHIO ENERGY GROUP

SEDWAY CONSULTING, INC.
BOULDER, COLORADO

September 2014

BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Duke Energy Ohio for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan, Accounting Modifications and Tariffs for Generation Service.	)))))))	**Case No. 14-841-EL-SSO**
In the Matter of the Application of Duke Energy Ohio for Authority to Amend its Certified Supplier Tariff, P.U.C.O. No. 20.	))))	**Case No. 14-842-EL-ATA**

EXHIBIT_(AST-1)

OF

ALAN S. TAYLOR

ON BEHALF OF

THE OHIO ENERGY GROUP

SEDWAY CONSULTING, INC.
BOULDER, COLORADO

September 2014

EXHIBIT__(AST-1) RESUME OF ALAN S. TAYLOR

AREAS OF QUALIFICATION

Independent evaluation services for competitive bidding resource selection, integrated resource planning, market analysis, risk assessment, and strategic planning

EMPLOYMENT HISTORY

- President, Sedway Consulting, Inc., Boulder, CO, 2001-present
- Senior Member of PA Consulting, Inc., Boulder, CO, 2001
- Vice President, Global Energy Business Sector, PHB Hagler Bailly, Inc., Boulder, CO, 2000
- From Senior Associate to Principal, Utility Services Group, Hagler Bailly Consulting, Inc., Boulder, CO, 1991-1999
- Senior Consultant, Energy Management Associates, Atlanta, GA, 1983-1988
- Internships at: Pacific Gas & Electric Company, San Francisco, CA (1990)
Lawrence Berkeley National Laboratory, Berkeley, CA (1989-1991)
MIT Resource Extraction Laboratory, Cambridge, MA (1982)
Baltimore Gas and Electric Company, Baltimore, MD (1980)

EDUCATION

- Walter A. Haas School of Business, University of California at Berkeley, MBA, Valedictorian, Corporate Finance, 1991
- Massachusetts Institute of Technology, BS, Energy Engineering, 1983

PROFESSIONAL EXPERIENCE

- Conducted numerous competitive bidding project evaluations for conventional generating resources, renewable facilities, and off-system power purchases; analyzed thousands of such power supply proposals.
- Developed and/or reviewed dozens of requests for proposals for utility resource solicitations.
- Assisted in or monitored contract negotiations with hundreds of shortlisted bidders in utility resource solicitations.
- Testified on utility competitive bidding solicitation results, affiliate transactions, cost recovery procedures, rate case calculations, and incentive ratemaking proposals.
- Managed the development of market price forecasts of North American and European electricity markets under deregulation.
- Performed financial modeling of electric utility bankruptcy workout plans.
- Trained and assisted many of the nation's largest electric and gas utilities in their use of operational and strategic planning computer models.

SELECTED PROJECTS

2014 **Analysis of Ohio Hedging Transaction**
Client: Ohio Energy Group

Analyzed and provided expert testimony in AEP-Ohio's Energy Security Plan/Standard Service Offer proceeding regarding the hedging and price stabilizing benefits of a proposed rider for the net benefits associated with utility's entitlement to the Ohio Valley Electric Corporation's generating assets.

2013- **California Solicitations for Resources**
2014 Client: Southern California Edison

Currently serving as the Independent Evaluator (IE) in Southern California Edison's (SCE) Local Capacity Requirements Request for Offers (LCR RFO) for 1,900-2,500 MW of new local capacity resources from energy efficiency, demand response, energy storage and/or gas-fired facilities. Also served as the IE for all five of SCE's 2013 reverse energy auctions of the dispatch rights to facilities under power purchase agreements executed with developers of facilities selected in the utility's 2006 New Generation RFO.

2013- **Florida Solicitation for Resources**
2014 Client: Duke Energy Florida

Provided Independent Monitor/Evaluator services in a solicitation for over 1,600 MW of power supplies for Duke Energy Florida's supply portfolio that were needed by the end of 2018. Mr. Taylor participated in all bidder conferences, was copied on all emails between the utility and bidders, performed an independent evaluation of all proposals, and testified before the Florida Public Service Commission regarding the solicitation's results.

2013 **Minnesota Solicitation for New Resources**
Client: Minnesota Power Company

Provided independent evaluation services in a solicitation for 220 MW of wind generation in Minnesota; bids were compared to the utility's proposal to develop its own wind farm. Mr. Taylor assisted with the development of the request for proposals (RFP), performed a parallel economic evaluation of the utility's facility and all competing proposals, monitored communications and negotiations with shortlisted bidders, and provided a report for filing with the Minnesota Public Utilities Commission regarding the results of the solicitation.

2013 **Kentucky Renewable Resource Analysis**
Client: Kentucky Industrial Utility Customers

Provided expert analysis and testimony on behalf of customers of Kentucky Power regarding a renewable energy purchase agreement for output from a new 58 MW biomass facility that is expected on-line in 2017.

2006- **California Solicitations for Conventional and Renewable Resources**
2013 Client: Southern California Edison

Currently serving or has served as the IE in 23 solicitations for power or gas supplies in southern California – one, as noted above, for SCE's 2013 LCR RFO, an earlier one for over 2,500 MW of new conventional resources, four for renewable energy purchases to help SCE meet its state Renewables Portfolio Standard (RPS) requirements, five for near-term capacity resources, eight for reverse energy auctions of the dispatch rights to facilities under power purchase agreements, and four for gas financial hedging products. Mr. Taylor managed or is managing a Sedway Consulting team to perform a parallel evaluation of all proposals, monitor communications and negotiations with power suppliers, and support the review of the final selected proposals by the Procurement Review Group – a collection of non-market-participant stakeholders and regulators who are/were provided confidential access to the evaluation results at intermediate stages. He has filed IE reports and sponsored testimony before the California Public Utilities Commission concerning the results of most of these solicitations.

2012 **Florida Solicitation for New Resources**
Client: Tampa Electric Company

Served as an independent evaluator in a solicitation for 500 MW of power supplies in Florida. New capacity had to be on-line by 2017; bids were compared to the utility's proposal to repower four existing combustion turbines into a larger combined-cycle facility. Mr. Taylor assisted with the development of the RFP, performed a parallel evaluation of all proposals, monitored communications and negotiations with contracting counterparties, and testified before the Florida Public Service Commission regarding the solicitation's results.

2011 **Minnesota Solicitation for Wind Resources**
Client: Minnesota Power

Provided independent evaluation services in a solicitation for 100 MW of wind generation in Minnesota. Proposals competed with a utility proposal to develop its own wind farm. Mr. Taylor assisted with the development of the RFP and performed a parallel economic evaluation of the utility's facility and all competing proposals.

2005- **California Solicitations for Conventional and Renewable Resources**
2010 Client: Pacific Gas & Electric

Served as the Independent Evaluator in four solicitations for new power supplies in northern California – one for 2,200 MW of new conventional resources, another for up to 1,200 MW of new generating resources from any source, and two others for between 1,400 and 2,800 GWh/year of renewable energy purchases. Mr. Taylor managed a Sedway Consulting team to perform a parallel evaluation of all proposals, monitor communications and negotiations with power suppliers, and support the review of the final selected proposals by the Procurement Review Group – a collection of non-market-participant stakeholders and regulators who were provided confidential access to the evaluation results at intermediate stages. He has filed IE reports and sponsored testimony before the California Public Utilities Commission concerning the results of most of these solicitations.

2007- **Florida Solicitation for New Resources**
2008 Client: Florida Power & Light

Provided independent evaluation services in Florida Power & Light's solicitation for 1,250 MW of new power supplies for 2011. Mr. Taylor performed a parallel economic evaluation to that which was undertaken by the utility. His work efforts allowed all proposal parameters to be cross-checked and corrected where necessary. He sponsored testimony before the Florida Public Service Commission concerning the results of the solicitation evaluation.

2007- **Avoided Cost Analysis for Interruptible Loads**
2008 Client: Public Service Company of Colorado

Provided an independent assessment of Public Service Company of Colorado's peaking resource avoided costs for use in the utility's development of customer credits for its interruptible service tariff.

2007- **Florida Solicitations for New Resources**
2008 Client: Tampa Electric Company

Provided independent evaluation services in two separate Tampa Electric Company solicitations for 600 MW of new power supplies for 2013, as a market test for the utility's proposals to develop initially an integrated gasification combined cycle (IGCC) facility and later a gas-fired combined cycle facility.

2004- **Regulatory Support of Commission Staff**
2005 Client: Utah Division of Public Utilities

Assisted staff for the Utah Division of Public Utilities in the division's efforts to analyze PacifiCorp's 2005 rate case. Mr. Taylor reviewed production cost modeling results and forecasts of system-wide fuel and purchase power costs.

2004- **Minnesota Solicitation for New Resources**
2005 Client: Minnesota Power

Provided independent evaluation services in a solicitation for 200 MW of firm power supplies. Mr. Taylor reviewed all proposals and performed a parallel economic evaluation among proposed turnkey facilities and power purchases.

2004 **Canadian Solicitations for Conventional and Renewable Resources**
Client: Ontario Energy Ministry

Participated in a broader consulting team and provided assistance in the development of RFPs for 2,500 MW of conventional resources and 300 MW of renewable resources. New long-term sources of power were sought to replace regional coal-fired generation.

2003- **Florida Solicitation for New Resources**
2004 Client: Florida Power & Light

Provided independent evaluation services in Florida Power & Light's solicitation for 1,100 MW of new power supplies for 2007. Mr. Taylor performed a parallel economic evaluation of all proposals and reviewed, cross-checked, and corrected (where necessary) the utility's analyses. He sponsored testimony before the Florida Public Service Commission concerning the results of the solicitation evaluation.

2002- **Minnesota Solicitation for New Resources**
2003 Client: Northern States Power

Assisted in the evaluation of a large number of multi-option proposals for new power supplies in the 2005-2009 time frame. Mr. Taylor was the independent evaluator in two separate solicitations. He managed a team of individuals in the evaluation of responses for both Requests for Proposals (RFPs). In the first solicitation, contingent proposals were received that could serve as replacement contracts for 1,100 MW of nuclear capacity if NSP were forced to decommission its Prairie Island power plant in 2007. In the second solicitation, NSP sought approximately 1,000 MW of new supplies to supplement its existing supply portfolio. The evaluation included the review of over a dozen proposed wind projects.

2002 **Florida Revisions to Bidding Rule**
Client: Consortium of utilities

Provided the Florida Public Service Commission with recommendations concerning appropriate revisions to the state's bidding rule. Mr. Taylor participated in public workshops to provide the benefits of his extensive experience in performing competitive bidding solicitations and to convey what changes should or should not be made to Florida's existing bid rule to ensure the selection of the best resources for the state's electricity customers.

2002 **Arizona Testimony Concerning Competitive Bidding Solicitations**
Client: Harquahala Generating Company, LLC

Filed testimony before the Arizona Corporation Commission in the Generic Proceedings Concerning Electric Restructuring Issues and Associated Proceedings. Mr. Taylor's testimony provided the Commission with information about competitive bidding processes that he had seen work in other states. Also, his testimony addressed various concerns that were raised by Arizona Public Service as to the feasibility of implementing competitive bidding in Arizona.

2002 **Florida Solicitation for New Resources**
Client: Florida Power & Light

Provided independent evaluation services in Florida Power & Light's solicitation for 1,750 MW of new power supplies in the 2005-2006 time frame. Mr. Taylor performed a parallel economic evaluation to that which was undertaken by the utility. His work efforts allowed all proposal parameters to be cross-checked and corrected where necessary. Also, he provided suggestions on resource optimization modeling approaches that ensured the most comprehensive examination of thousands of potential combinations of proposals.

2001 **Wisconsin Testimony Concerning Competitive Bidding Solicitations**
Client: MidWest Independent Power Suppliers

Provided testimony in a proceeding before the Wisconsin Public Service Commission on behalf of a consortium of independent power producers. Mr. Taylor testified on the benefits and timing of a competitive bidding solicitation that Wisconsin Electric Power Company (WEPCO) should be ordered to conduct prior to the utility's development of $2.8 billion in self-build generation facilities (embodied in a WEPCO proposal called Power the Future – 2). Without the benefits of a competitive solicitation, there would be no defensible means of ensuring that the utility's customers were being offered the best, most cost-effective resources.

BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Duke Energy Ohio for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan, Accounting Modifications and Tariffs for Generation Service.	)	**Case No. 14-841-EL-SSO**
In the Matter of the Application of Duke Energy Ohio for Authority to Amend its Certified Supplier Tariff, P.U.C.O. No. 20.	)	**Case No. 14-842-EL-ATA**

EXHIBIT_(AST-2)

OF

ALAN S. TAYLOR

ON BEHALF OF

THE OHIO ENERGY GROUP

SEDWAY CONSULTING, INC.
BOULDER, COLORADO

September 2014

Exhibit__AST-2

Duke Energy Ohio's Projection of 2015-2023 OVEC Net Benefits – January 2014 Analysis*
Highly Confidential

line		2015	2016	2017	2018	2019	2020	2021	2022	2023
1	OVEC Capacity ICAP (MW)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	OVEC Capacity UCAP (MW)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	OVEC Energy (GWH)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	OVEC Capacity Factor (%)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	OVEC Demand Charge ($000)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	OVEC Demand Charge ($/MW-Day)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7	RPM price for capacity ($/MW-Day)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8	Capacity Revenue ($ 000)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9	Dividends ($000)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10	Energy Market Price ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11	Energy Revenue ($000)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
12	OVEC Energy Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
13	OVEC Cost of Generation ($000)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
14	OVEC Energy Gross Margin ($000)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
15	OVEC Revenue (Cap., En., and Div.)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
16	OVEC Cost (Demand & Energy)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
17	**OVEC Net Benefits ($000)**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
18	**Adjusted for initial partial year**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
19	**Cumulative**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Source: Duke Energy Ohio Response OEG-DR-01-001_Attachment_HIGH CONF.xlsx

*Note: 2015-2018 forecast values as of June 2014.

BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

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EXHIBIT_(AST-3)

OF

ALAN S. TAYLOR

ON BEHALF OF

THE OHIO ENERGY GROUP

SEDWAY CONSULTING, INC.
BOULDER, COLORADO

September 2014

Exhibit__AST-3, Page 1 of 3

Calculation of Modified Price Stabilization Rider (all values in $000)

Contains Highly Confidential Information

Line			NPV	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
1	**Forecasted OVEC Net Benefits**			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	N/A
2	**Year 1 Average Expected Savings**			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	**Regulatory Account - Forecasted**												
4	Balance - Beginning of Year			0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	Balance - End of Year			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	0
6	Balance - Average			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7	Calculated Return		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8	Levelized Return		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9	WACC	7.73%											
10	**Initial PPA Stability Rider**			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Exhibit__AST-3, Page 2 of 3

Calculation of Modified Price Stabilization Rider (all values in $000)

Contains Highly Confidential Information

Line		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
	Annual True-Up										
11	Actual OVEC Net Benefits ***(illustrative)***	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
12	Difference from Estimate	1,000	1,000	2,000	2,000	1,000	(1,000)	2,000	2,000	1,000	
	Amortization of Differences										
13	Calendar Year 2		(333)	(333)	(333)						
14	Calendar Year 3			(333)	(333)	(333)					
15	Calendar Year 4				(667)	(667)	(667)				
16	Calendar Year 5					(667)	(667)	(667)			
17	Calendar Year 6						(333)	(333)	(333)		
18	Calendar Year 7							333	333	333	
19	Calendar Year 8								(667)	(667)	(667)
20	Calendar Year 9									(1,000)	(1,000)
21	Calendar Year 10										(1,000)
22	Net Benefit Adjustments	-	(333)	(667)	(1,333)	(1,667)	(1,667)	(667)	(667)	(1,333)	(2,667)
	Regulatory Account - True-up Adjustment										
23	Balance - Beginning of Year	-	(1,000)	(1,667)	(3,000)	(3,667)	(3,000)	(333)	(1,667)	(3,000)	(2,667)
24	Balance - End of Year	(1,000)	(1,667)	(3,000)	(3,667)	(3,000)	(333)	(1,667)	(3,000)	(2,667)	-
25	Balance – Average	(500)	(1,333)	(2,333)	(3,333)	(3,333)	(1,667)	(1,000)	(2,333)	(2,833)	(1,333)
26	Calculated Return	(39)	(103)	(180)	(258)	(258)	(129)	(77)	(180)	(219)	(103)

Exhibit__AST-3, Page 3 of 3

Calculation of Modified Price Stabilization Rider (all values in $000)

Contains Highly Confidential Information

Line			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
27	Initial Annual Rider *(line 10)*		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
28	Net Benefit Adjustments *(line 22)*		-	(333)	(667)	(1,333)	(1,667)	(1,667)	(667)	(667)	(1,333)	(2,667)
29	Return on Regulatory Account - True-up Adj		-	(39)	(103)	(180)	(258)	(258)	(129)	(77)	(180)	(322)
	(line 26 – one year lag, except for final year)											
30	Revised Annual Rider		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
31	Duke Energy Ohio Percentage	10.0%										
32	**Final PPA Stability Rider (Customer Portion)**		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

In The Matter Of The Application Of Duke Energy Ohio, Inc. For Authority To Establish A Standard Service Offer Pursuant To Section 4928.143, Revised Code, In The Form Of An Electric Security Plan, Accounting Modifications And Tariffs For Generation Service	:	**Case No. 14-841-EL-SSO**
In The Matter Of The Application Of Duke Energy Ohio, Inc. For Authority To Amend Its Certified Supplier Tariff, P.U.C.O. No. 20	:	**Case No. 14-842-EL-ATA**

DIRECT TESTIMONY

OF

STEPHEN J. BARON

ON BEHALF OF

THE OHIO ENERGY GROUP

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

September 2014

BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

In The Matter Of The Application Of Duke Energy Ohio, Inc. For Authority To Establish A Standard Service Offer Pursuant To Section 4928.143, Revised Code, In The Form Of An Electric Security Plan, Accounting Modifications And Tariffs For Generation Service	:	**Case No. 14-841-EL-SSO**
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I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Stephen J. Baron. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by who are you employed?

A. I am the President and a Principal of Kennedy and Associates, a firm of utility rate, planning, and economic consultants in Atlanta, Georgia.

Q. Please describe briefly the nature of the consulting services provided by Kennedy and Associates.

A. Kennedy and Associates provides consulting services in the electric and gas utility industries. Our clients include state agencies and industrial electricity consumers. The firm provides expertise in system planning, load forecasting, financial analysis, cost-of-service, and rate design. Current clients include the Georgia and Louisiana Public Service Commissions, and industrial and commercial consumers throughout the United States. My educational background and professional experience are summarized on Baron Exhibit 1 (SJB-1).

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of The Ohio Energy Group ("OEG"), a group of large industrial customers of Duke Energy Ohio, Inc. ("Duke" or "Company"). The members of OEG who take service from the Company are: AK Steel Corporation, Air Products and Chemicals, Inc., E.I. du Pont de Nemours and Company, Ford Motor Company, GE Aviation, General Motors LLC and Worthington Industries.

Q. Have you previously presented testimony in any of the Company's cases in Ohio?

A. Yes. I have previously testified in Case Nos. 91-372-EL-UNC, 91-410-EL-AIR and 99-1658-EL-ETP (the Company's restructuring case in which rates were unbundled and the Company was restructured to implement retail competition), Case No. 10-2586-EL-SSO (Duke's 2010 Market Rate Offer proceeding), and Case No. 11-4393-EL-RDR (Duke's energy efficiency rider case).

Q. Have you previously presented testimony in Standard Service Offer cases in Ohio?

A. Yes. I have testified in a number of Electric Security Plan ("ESP") and Market Rate Offer cases involving the FirstEnergy operating companies and Ohio Power Company ("AEP Ohio"), in addition to the Duke case cited above. These include Case Nos. 08-935-EL-SSO, 08-936-EL-SSO, 09-906-EL-SSO, 10-2586-EL-SSO, 11-346-EL-SSO, and 13-2385-EL-SSO.

Q. What is the purpose of your testimony?

A. I discuss two issues associated with the Company's proposed ESP. I first address Duke's proposal to eliminate its existing large customer interruptible load program. Duke currently has two non-residential demand response programs – its PowerShare® program and the large customer interruptible program approved in its previous ESP case. Duke's PowerShare® interruptible load program will continue through part of the ESP period, but the Company seeks to abandon its large customer interruptible load program. I discuss why the Public Utilities Commission of Ohio ("Commission" or "PUCO") should simply modify the terms of participation in the large customer interruptible program. I also respond to Duke's proposal to eliminate its Load Factor Adjustment ("LFA") Rider, and provide an alternative approach to handling that Rider.

Q. Would you please summarize your testimony and recommendations?

A. Yes. The Commission should require Duke to continue an enhanced version of its large customer interruptible load program beyond May 31, 2015. The Commission should also require Duke to phase-down its LFA Rider through the proposed ESP period rather than simply eliminating that Rider and to modify the LFA Rider by removing approximately 19,000 of the smallest customers from the Rider. In the midst of the current uncertainties surrounding generation service in Duke's territory, it is important to maintain some level of stability for large customers.

Duke's rationale for terminating its large customer interruptible program is flawed. The Company's transition from a Fixed Resource Requirement ("FRR") Entity in PJM to a Reliability Pricing Model ("RPM") Entity as of June 1, 2015 will not alter the value of its large customer interruptible program. That program can continue to provide reliability, economic, and energy conservation benefits to customers even if not used as part of an FRR plan. Additionally, Duke's belief that interruptible load should receive only PJM-regulated pricing could result in all customers losing the benefits of interruptible resources because such pricing may not provide sufficient incentive for large customers to offer their load for interruption. Also, the legality of PJM's demand response program is in serious question.

While Duke proposes to abandon the large customer interruptible program, the Company touts the benefits of its other demand response program, the PowerShare® program. But these programs are similar in function and the rationale for preserving the PowerShare® program supports the continuation of the large customer interruptible program as a complimentary option.

Rather than abandoning the large customer interruptible program during the proposed ESP period, the Commission should modify its terms by requiring participating customers to be subject to interruption throughout the year, instead of only during summer months, for emergency purposes only. The level of the interruptible credit (50 percent of the PJM Net Cost of New Entry, or "Net CONE") should remain the same. This will preserve the benefits of the interruptible resources in Duke's territory and maintain some rate stability for large customers while also providing even greater value to other customers in Duke's territory throughout the ESP period.

Also, Duke's LFA Rider should not be immediately terminated as of May 31, 2015. Instead, it should be gradually phased-down to preserve the program and to soften the rate impact on high load factor customers. FirstEnergy has proposed a comparable approach with regard to a similar rider in its most recent ESP case, although FirstEnergy's approach involves a phase-out rather than a phase-down. The Commission should also modify the LFA Rider such that it only applies to approximately 310 customers served under Rates DP and TS. This will prevent any potential adverse impacts of the LFA Rider on approximately 19,000 smaller Rate DS customers.

II. DUKE'S LARGE CUSTOMER INTERRUPTIBLE LOAD PROGRAM SHOULD BE CONTINUED THROUGHOUT THE PROPOSED ESP PERIOD

Q. Please provide some background on the status of generation service in Duke's service territory.

A. In its previous ESP case, 11-3549-EL-SSO, Duke agreed to divest its generation assets and to use competitive bidding processes to set its Standard Service Offer ("SSO") rates. In furtherance of its commitment to divest its generation assets, Duke recently announced that it is selling those assets to Dynegy, Inc. Duke's parent company, Duke Energy, Inc., is the largest utility in the country, with operations in many states, and is headquartered in Charlotte, North Carolina.

Duke proposes to continue setting its SSO rates through competitive bidding processes during the ESP period proposed in this case. Hence, customers would remain subject to uncertainty and market risk throughout that time. Market prices could fluctuate depending upon natural gas prices, coal plant retirements, proposed environmental regulations (i.e. the U.S. Environmental Protection Agency's Rule 111(d) proposal), events such as last winter's "polar vortex," or other factors. In light of the uncertainties and risks associated with Duke's chosen rate-setting approach, the Commission should take steps to provide greater rate stability to customers during the ESP period.

Q. Please provide your understanding of Duke's large customer interruptible load program.

A. Duke's current large customer interruptible program was established as a result of the Commission's approval of the Stipulation and Recommendation in Duke's last ESP proceeding, Case No. 11-3549-EL-SSO. Under that program, transmission voltage customers, whether shopping or non-shopping, with loads in excess of 10 MW at a single site can nominate any part of their load as being subject to interruption by Duke. In exchange for subjecting their load to interruption, participating customers receive an interruptible credit equal to 50 percent of the PJM Net CONE, which is the cost of a new combustion turbine, net of energy and ancillary service credits. The costs of the large customer interruptible program are recovered through Duke's Economic Competitiveness Fund Rider (Rider DR-ECF).

There are currently four customers participating in the Company's large customer interruptible program. These customers have agreed to subject a significant amount of MW to potential interruption by Duke.[1]

Q. Have you reviewed the Company's proposal to terminate its large customer interruptible load program at the end of the current ESP?

A. Yes. Duke currently has two Commission-approved demand response programs - the PowerShare® program and the large customer interruptible program. Duke's PowerShare® program will remain in place with no changes through part the ESP period, pursuant to the Commission's Order in Duke's last EE/PDR portfolio case, 13-431-EL-POR. But as discussed by Company witnesses William Don Wathen and James Ziolkowski, Duke is proposing to abandon its current large customer interruptible program with the initiation of its new ESP beginning June 1, 2015. Duke's first rationale for abandoning the program is that the Company will no longer be an FRR Entity in PJM as of June 1, 2015 and therefore will not need the interruptible resources to meet its FRR obligations. Duke's second rationale is its belief that the value of the interruptible resources in its service territory should be determined by PJM and not by this Commission.

[1] The Company provided the MW of interruptible contract capacity in its response to OEG-DR-02-001.

Q. Do you agree that it is appropriate to terminate Duke's large customer interruptible load program?

A. No. I question the Company's rationale for abandoning the program. Moreover, there are many benefits to continuing an enhanced version of the large customer interruptible program that would be lost if it were terminated. Duke recognizes the benefits of demand response programs such as the large customer interruptible load program when supporting its PowerShare® demand response program.

Q. Why do you question Duke's rationale for terminating its large customer interruptible load program?

A. Duke's change of status from an FRR Entity to a participant in the PJM RPM capacity auctions will not impact the value of the interruptible load in its service territory. While Duke may not need the interruptible load currently participating in its program as part of an FRR plan after May 31, 2015, under present circumstances, the Company could still bid that load into the PJM RPM market as a capacity resource. And that interruptible load could continue to provide reliability, economic, and energy efficiency benefits if used either as part of the PJM RPM auctions or simply at the state level.

As to Duke's second rationale, PJM pricing may not provide sufficient incentive for customers to subject their businesses to interruptions. If customers with interruptible load choose not to participate in the PJM demand response programs due to insufficient compensation, then the potential benefits of that interruptible load to all customers would be lost.

The PJM Base Residual Auctions ("BRA") through May 31, 2018 have already occurred. Consequently, over the proposed ESP period, customers with interruptible load could only participate in the PJM incremental auctions. And the capacity pricing resulting from incremental auctions has historically been unpredictable, and often significantly lower than the standard RPM capacity prices produced by the annual BRAs. Baron Exhibit 2 (SJB-2) shows a history of the RPM prices produced by BRAs and incremental auctions since the beginning of the RPM capacity market.

As can be seen, the RPM capacity prices (interruptible credit rate for demand response load) are often significantly lower than the corresponding year's BRA RPM price. For example, in delivery year 2014/2015, the BRA resulted in capacity price of $125.47/MW-day. The corresponding prices for the 1st and 2nd incremental auctions were $0.03/MW-day and $25/MW-day. This equates to an interruptible credit of approximately $0/kW-month and $0.76/kW-month.

While the 2015/2016 1st incremental auction produced an RTO price of $43/MW-day and the 2015/2016 recent 2nd incremental auction cleared at $136/MW-day (compared to the 2015/2016 BRA price of $136/MW-day), the recent extreme volatility of the incremental auctions would continue to create a potential barrier to Duke interruptible customers who would no longer have the Duke program available, if there is not a replacement alternative.

Because of the significant uncertainty regarding the ability of the incremental auctions to provide realistic, economic payments for interruptible load that has been previously committed to the Duke interruptible program, incremental auctions may not provide a realistic substitute for a Duke specific large customer interruptible program.

Counsel also informs me that a recent decision by the D.C. Circuit Court calls into question whether PJM will be permitted to continue allowing demand response resources to participate in its energy and capacity markets.[2] And the U.S. Court of Appeals for the D.C. Circuit recently refused to grant review of that decision. *See* Baron Exhibit 3 (SJB-3). It is therefore important that the Commission retain a state-administered interruptible load program in order to preserve the benefits offered by interruptible resources. If the PJM demand response program is eventually terminated as a result of this ruling, then an Ohio-specific interruptible program would be the only recourse for Ohio industrial customers.

Further, in his comments submitted in response to PJM's proposed performance standards, the PJM Independent Market Monitor ("IMM") raised a serious question

[2] *Electric Power Supply Association v. Federal Energy Regulatory Commission*, D.C. Circuit Case No. 11-1486 (May 23, 2014).

regarding the continuation of the PJM demand response program in the capacity market. On page 8 of his comments, the IMM stated as follows:

> The capacity market should no longer include any demand side resources on the supply side of the market, including energy efficiency resources (EE). Demand side resources should be on the demand side of the market where they can and should be a very significant component of the capacity market. PJM needs to take clearly defined steps to facilitate such demand side participation. Load that does not want to pay for capacity and is willing to interrupt its use of capacity when that capacity is needed by those who do pay for it, should be able to avoid paying for capacity. That is the demand side of the market as it should work and can work.[3]

Clearly, there is a significant level of uncertainty regarding the PJM demand response program from a number of perspectives. A Duke interruptible load program under the regulation of the Ohio Commission would ensure the continuation of reliability benefits of interruptible load for Ohio, regardless of the outcome of PJM IMM recommended changes or Court proceedings related to FERC Order 745 that may remove demand response entirely from participation in the PJM capacity market.

Q. What benefits are provided by state-sponsored interruptible load programs?

A. State-sponsored interruptible load programs provide reliability, economic, and energy efficiency benefits. The interruptible load of large customers can be used to reduce strains on the electric grid during peak times, increasing the reliability of the grid. In addition, interruptible resources can provide economic benefits by lowering market prices for all consumers during peak times and by reducing the need for

[3] Comments of the Independent Market Monitor on PJM's Capacity Performance Proposal and IMM Proposal, The Independent Market Monitor for PJM, September 17, 2014.

additional capacity resources to be constructed. Interruptible load programs can also bolster economic development by allowing large customers, who must compete both nationally and internationally, to secure more competitive electric rates by choosing to take a lower quality of service from their utility. Finally, interruptible load programs increase energy conservation by reducing the amount of power that would otherwise be consumed during peak times.

Q. Has the Commission already recognized the benefits of state-sponsored interruptible load programs?

A. Yes. In its Order in Case No. 11-346-EL-SSO, the Commission specifically recognized the benefits of AEP Ohio's interruptible load program and approved an interruptible credit of $8.21/kW-month, stating:

> The Commission finds the IRP-D credit should be approved as proposed at $8.21/kW-month. In light of the fact that customers receiving interruptible service must be prepared to curtail their electric usage on short notice, we believe Staff's proposal to lower the credit amount to $3.34/kW-month understates the value interruptible service provides both AEP-Ohio and it customers. In addition, the IRP-D credit is beneficial in that it provides flexible options for energy intensive customers to choose their quality of service, and is also consistent with state policy under Section 4928.02(N), Revised Code, as it furthers Ohio's effectiveness in the global economy. In addition, since AEP-Ohio may utilize interruptible service as an additional demand response resource to meet its capacity obligations, we direct AEP-Ohio to bid its additional capacity resources into PJM's base residual auctions held during the ESP.

Q. Will any of these Commission-cited benefits of a state-sponsored interruptible load program change as a result of Duke's proposed ESP?

A. No, not in my opinion. All of the benefits that were cited by the Commission for AEP Ohio's interruptible load program also support the continuation of Duke's large customer interruptible load program during the term of the proposed ESP.

Q. Has Duke recognized the benefits that can be provided by demand response programs like state-sponsored interruptible load programs?

A. Yes. As I discuss below, Duke highlights the benefits of demand response programs in support of its PowerShare® program.

Q. Has the reliability benefit of interruptible load been recently confirmed in Ohio and in PJM as a whole?

A. Yes. The extreme cold temperatures during January 2014 caused significant reliability problems for PJM. According to reporting by SNL Financial, PJM was "particularly hard hit" by outages and other weather related reliability problems. The availability of demand response (including interruptible load) provided emergency capacity to meet firm loads during this period. PJM lost "roughly 40,000 MW of generating capacity" during the coldest, highest load periods. This represented 20% of PJM's generating capacity. Of this lost capacity, 9,000 MW was due to gas curtailments. Baron Exhibit 4 (SJB-4) contains excerpts from these SNL Financial articles.

PJM's own estimates indicate that it could fail to meet its peak load requirements in the winter of 2015/2016 if it faces generator outages, extreme cold, and expected coal retirements at a similar rate as last winter. Heightened concern over potential reliability issues resulted in PJM's recent proposal to establish a new product known as "capacity performance" for its RPM market. Baron Exhibit 5 (SJB-5) provides an SNL article on this matter. This development highlights the value of resources that can provide additional reliability to the electric grid, such as interruptible load.

Q. **Are there other factors that are expected to potentially adversely impact available capacity in PJM over the next few years?**

A. Yes. Electric utilities in PJM, MISO and other reliability regions are expected to retire over 27,000 MW of coal capacity over the next 9 years, with 24,000 MW of that occurring during the next four years. In PJM, 10,400 MW of coal capacity is expected to be retired in just 2014 and 2015. More than half of these retirements are AEP East coal units located in Ohio, Kentucky, West Virginia, and Indiana. These retirements will tighten the demand/supply balance in PJM, thus increasing the value of reliability. Baron Exhibit 6 (SJB-6) contains summary information on these coal unit retirements from a recent SNL Financial article (March 25, 2014).

Q. If the Commission were to approve Duke's proposal to terminate its large customer interruptible load program, would this place the Company's large industrial customers at a disadvantage relative to similar large industrial customers in Northern Ohio?

A. Yes. Such an approval would set an inconsistent policy for customers in Duke's service territory compared to customers in the FirstEnergy operating companies' service territories. A steel mill in Northern Ohio would potentially have a significant economic advantage over a similar customer in Duke's service territory.

Q. If its current interruptible program is terminated, what other possible options has Duke suggested for market participation by customers with interruptible load?

A. When asked in discovery about possible options available to Duke's interruptible customers for the PJM 2017/18 Delivery Year, Duke responded that "…customers can now participate indirectly, or directly, in PJM's DR program 2017/18 delivery year under one of several methods:

> Indirectly, by participating with Duke Energy Ohio under the PowerShare®.
>
> Indirectly, by participating with another CSP's DR program in the PJM 2017/18 Incremental Capacity Auctions.
>
> Registering its DR resources with PJM and participating directly in the PJM 2017/18 Incremental Capacity Auctions."
>
> [Duke's discovery response is attached as Baron Exhibit 7 (SJB-7).]

Two of the three options presented by Duke are not realistic. Specifically, Duke suggests that interruptible customers could participate in the PJM incremental auctions either directly by registering with PJM or indirectly through a curtailment service provider. But as discussed above, PJM incremental auction pricing may not be sufficient to incentivize customers to interrupt their operations on short notice.

Q. What is your response to Duke's third suggested option?

A. The PowerShare® demand response program may be an option for some customers with interruptible load, but Duke's current large customer interruptible load program is complimentary to that program and can provide additional benefits. For instance, if the Commission approves my proposed enhancement to the large customer interruptible load program - modifying the terms of participation such that customers are subject to unlimited emergency-only interruptions throughout the year - then that program will provide greater reliability to customers than the PowerShare® program.

Q. Does the existence of the PowerShare® program support continuation of Duke's interruptible load program?

A. Yes. The rationale for maintaining the PowerShare® program is the same as the rationale for continuing the large customer interruptible load program. Both programs can provide reliability, economic, and energy efficiency benefits to customers. In exchange, participating customers receive a credit on their bills.

Duke discusses the benefits of its PowerShare® program in the 2014/15 program brochure, attached as Baron Exhibit 8 (SJB-8), stating:

- "Building new generation facilities is costly, time-consuming and offers no immediate relief. Demand-response programs are the cheapest, fastest, and cleanest way to meet energy demand, while providing our business customers with a way to profit from their energy curtailment."

- "Participation in PowerShare provides economic and environmental benefits…helps maintain low energy rates by reducing the need for new generation plants. Mitigates electrical emergencies, increases system reliability and reduces customer inconvenience. Reduces the need to run expensive generation plants during high demand, resulting in lower wholesale market prices and end-user savings..."

These same benefits apply to Duke's current large customer interruptible program. That program is complimentary to the PowerShare® program since it provides another option for participation and greater incentive for customers to subject their businesses to interruption.

Moreover, Duke's opposition to continuing its large customer interruptible load program is based in part on a belief that PJM should determine the value of demand response resources. But Duke's PowerShare® program provides PUCO-determined compensation for demand response resources. Thus, the existence of Duke's PowerShare® program undermines the Company's argument against continuing the large customer interruptible load program.

Q. What other benefit would continuing the large customer interruptible load program provide?

A. Continuing the program would provide greater rate stability for interruptible customers who currently base their planning and operations on participation in the program. Such stability is important in light of the uncertainties surrounding Duke's generation service rates throughout the ESP period.

Q. What enhancement to the large customer interruptible load program do you recommend?

A. In order to provide even greater value to other customers as a result of the large customer interruptible load program, I recommended that the terms of participation in the program be modified. Specifically, the Commission should require that participating customers be subject to unlimited emergency-only interruptions throughout the year, rather than only in the summer months. However, the level of the interruptible credit should remain the same (50 percent of the PJM Net CONE).

This modification would provide even greater reliability to other customers, particularly if an event like last winter's "polar vortex" occurs during the proposed ESP period, at the same cost as the current large customer interruptible load program. It will also compliment Duke's PowerShare® program, which is only applicable during the summer months, by providing demand response resources throughout the year.

Q. How does Duke's pending divestiture of its generation assets impact your opinion?

A. The pending sale of Duke's generation assets to Dynegy, Inc. does not alter my recommendation. This Commission has approved interruptible programs and associated credits for other utilities that have divested or are currently in the process of divesting their generation. The Commission approved an interruptible credit for FirstEnergy's large industrial customers as part of FirstEnergy's current ESP. FirstEnergy has long been a "wires-only" company, having divested its generation in the mid-2000's. Yet the Commission approved FirstEnergy's interruptible credit of $10/kW-month and the program (and rate) continue despite that fact. Additionally, the Commission approved an interruptible program for Duke in its last ESP, even though Duke committed to divest its generation in that case.

Q. What mechanism do you recommend for Duke to recover the costs associated with the interruptible credits that would be paid under OEG's proposal?

A. The Commission should require Duke to continue recovering the costs associated with any interruptible credits through Rider DR-ECF. Also, Duke should be required to maximize the financial value of the interruptible capacity by bidding it into the appropriate PJM capacity auction and credit that revenue back to consumers. This crediting approach was required when the Commission approved the AEP Ohio's current interruptible program.

III. THE LOAD FACTOR ADJUSTMENT RIDER SHOULD BE MODIFIED TO REMOVE THE SMALL BUSINESS CUSTOMERS AND BE PHASED-DOWN RATHER THAN TERMINATED

Q. Please provide your understanding of Duke's LFA Rider.

A. Duke's current LFA Rider was adopted in its last ESP case. The LFA Rider is a non-bypassable charge and credit designed to stabilize electric service by enhancing some of the benefits received by high load factor customers. The current LFA Rider applies to customers served under Rates DS, DP, and TS.

Q. Have you reviewed Duke's proposal to terminate the LFA Rider.

A. Yes. Duke witnesses Wathen and Ziolkowski describe the proposed immediate termination of the LFA Rider as of May 31, 2015. The Company's wishes to terminate the LFA Rider due to its belief that the price customers pay for all generation-related costs should be established by PJM. Duke states that high load factor customers should be rewarded with appropriate offers by competitive suppliers or in the form of lower SSO rates (citing its proposed changes to the Retail Capacity Rider) instead.

Q. What is your response to Duke's proposal?

A. I disagree that the LFA Rider should be immediately terminated as of June 1, 2015. Instead, I recommend that the LFA Rider be preserved, but gradually phased-down beginning June 1, 2016 such that the demand charge under the Rider is reduced by half at the end of Duke's proposed ESP period. I also recommend one modification to the current LFA Rider to prevent adverse impacts to the approximately 19,000 smaller customers on Rate DS.

Q. Why should the Commission phase-down rather than terminate completely the LFA Rider?

A. By preserving, but phasing-down the level of the LFA Rider over the proposed ESP period, the Commission can continue some of the LFA Rider benefits to high load factor customers, while easing any adverse impacts of the Rider on other customers. This gradual phase-down approach will provide a reasonable level of time for large, industrial customers, many of whom face significant competitive pressures nationally and internationally, to adjust to what would otherwise be a significant change in their power costs.

This approach is also consistent with the ratemaking principle of gradualism since it will soften the harm to high load factor customers who have grown to depend upon the LFA Rider during Duke's current ESP. Further, it will lessen adverse economic development impacts associated with increasing rates on large high load factor customers.

Q. How would your recommended phase-down of the LFA Rider work?

A. To phase-down the LFA Rider, I recommend that the demand charge gradually be reduced over the proposed ESP period. In year one of the proposed ESP (June 1, 2015 through May 31, 2016), the LFA demand charge would be maintained at its current level of $8 per kVa of billing demand, though recalculated to remove DS customers. In year two (June 1, 2016 through May 31, 2017), the demand charge would be reduced to $6 per kVa of billing demand. In year three (June 1, 2017 through May 31, 2018), the demand charge would be reduced to $4 per kVa of billing demand. Thus, the demand charge would be cut in half by the end of the proposed ESP period. As the demand charges are reduced, the design of the LFA Rider would also result in decreasing energy credits to maintain revenue neutrality among all DP and TS customers.

Q. Has Duke presented any information on the impact of its proposed elimination of the LFA Rider beginning June 1, 2015?

A. No. The typical bill impact analyses presented by Mr. Ziolkowski remove the effect of the LFA Rider from both current and proposed rates. The impact of eliminating the LFA Rider immediately, as Duke proposes, for an 82% load factor TS customer will result in a rate increase in the range of 14%. Phasing down the LFA Rider, coupled with eliminating DS customers from the Rider, will result in increases of about 8% the first year, 10% the second year, and about 11% in year three of the ESP. A phase-down of the LFA Rider will provide a more reasonable transition than the Company's proposal to eliminate the Rider immediately beginning June 1, 2015.

Q. How else should the Commission modify the LFA Rider?

A. The Commission should also modify the LFA Rider by requiring that the Rider only apply to the approximately 310 customers taking service under Rates DP and TS over the proposed ESP period. This will prevent adverse rate impacts to approximately 19,000 smaller customers currently taking service under Rate DS. With this one modification, the Commission could eliminate 98.4% of the customers currently impacted by the LFA from being impacted through the proposed ESP period.

Q. Would you summarize your position regarding the Company's proposal to terminate the LFA Rider?

A. Yes. OEG is proposing to incorporate a measure of gradualism into the LFA Rider issue in response to Duke's proposal to simply terminate the Rider immediately on May 31, 2015. The OEG alternative "phase-down" proposal accomplishes the same objectives as Duke's proposal with an important distinction that is supportable under standard regulatory policies – the incorporation of gradualism. The OEG proposal immediately (beginning in June 2015) eliminates thousands of smaller DS customers from the Rider, who tend to have lower load factors and would otherwise face higher rates with the Rider in place. For the remaining three hundred or so DP and TS customers, the OEG proposal phases-down the demand charge starting in the second year of the ESP from \$8/kW month to \$6/kW month. In the third year, the demand charge is reduced to \$4/kW month. In each of the three years of the ESP, the corresponding LFA energy credit will be reduced (it is reduced even in year one because of the elimination of DS customers from the revenue-neutral rate calculation). Under the OEG proposal, the percentage increases that higher load factor DP and TS customers would otherwise face under Duke's immediate termination will be mitigated and only gradually occur. This is the essence of gradualism in ratemaking and should be adopted by the Commission in this case.

Q. Does that complete your Direct Testimony?

A. Yes.

AFFIDAVIT

STATE OF GEORGIA)

COUNTY OF FULTON)

STEPHEN J. BARON, being duly sworn, deposes and states: that the attached is his sworn testimony and that the statements contained are true and correct to the best of his knowledge, information and belief.

Stephen J. Baron

Stephen J. Baron

Sworn to and subscribed before me on this 26th day of September 2014.

Jessica K. I

Notary Public

JESSICA K INMAN
MY COMMISSION EXPIRES
NOTARY
PUBLIC
JULY 31, 2015
CHEROKEE COUNTY, GEORGIA

BEFORE THE

PUBLIC UTILITY COMMISSION OF OHIO

In The Matter Of The Application Of Duke Energy Ohio, Inc. For Authority To Establish A Standard Service Offer Pursuant To Section 4928.143, Revised Code, In The Form Of An Electric Security Plan, Accounting Modifications And Tariffs For Generation Service	:	**Case No. 14-841-EL-SSO**
In The Matter Of The Application Of Duke Energy Ohio, Inc. For Authority To Amend Its Certified Supplier Tariff, P.U.C.O. No. 20	:	**Case No. 14-842-EL-ATA**

EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF

THE OHIO ENERGY GROUP

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

September 2014

BEFORE THE

PUBLIC UTILITY COMMISSION OF OHIO

In The Matter Of The Application Of Duke Energy Ohio, Inc. For Authority To Establish A Standard Service Offer Pursuant To Section 4928.143, Revised Code, In The Form Of An Electric Security Plan, Accounting Modifications And Tariffs For Generation Service	:	**Case No. 14-841-EL-SSO**
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EXHIBIT_(SJB-1)

OF

STEPHEN J. BARON

ON BEHALF OF

THE OHIO ENERGY GROUP

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

September 2014

Professional Qualifications

Of

Stephen J. Baron

Mr. Baron graduated from the University of Florida in 1972 with a B.A. degree with high honors in Political Science and significant coursework in Mathematics and Computer Science. In 1974, he received a Master of Arts Degree in Economics, also from the University of Florida. His areas of specialization were econometrics, statistics, and public utility economics. His thesis concerned the development of an econometric model to forecast electricity sales in the State of Florida, for which he received a grant from the Public Utility Research Center of the University of Florida. In addition, he has advanced study and coursework in time series analysis and dynamic model building.

Mr. Baron has more than thirty years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning, and economic analysis.

Following the completion of my graduate work in economics, he joined the staff of the Florida Public Service Commission in August of 1974 as a Rate Economist. His responsibilities included the analysis of rate cases for electric, telephone, and gas utilities, as well as the preparation of cross-examination material and the preparation of staff recommendations.

In December 1975, he joined the Utility Rate Consulting Division of Ebasco Services, Inc.

as an Associate Consultant. In the seven years he worked for Ebasco, he received successive promotions, ultimately to the position of Vice President of Energy Management Services of Ebasco Business Consulting Company. His responsibilities included the management of a staff of consultants engaged in providing services in the areas of econometric modeling, load and energy forecasting, production cost modeling, planning, cost-of-service analysis, cogeneration, and load management.

He joined the public accounting firm of Coopers & Lybrand in 1982 as a Manager of the Atlanta Office of the Utility Regulatory and Advisory Services Group. In this capacity he was responsible for the operation and management of the Atlanta office. His duties included the technical and administrative supervision of the staff, budgeting, recruiting, and marketing as well as project management on client engagements. At Coopers & Lybrand, he specialized in utility cost analysis, forecasting, load analysis, economic analysis, and planning.

In January 1984, he joined the consulting firm of Kennedy and Associates as a Vice President and Principal. Mr. Baron became President of the firm in January 1991.

During the course of his career, he has provided consulting services to more than thirty utility, industrial, and Public Service Commission clients, including three international utility clients.

He has presented numerous papers and published an article entitled "How to Rate Load Management Programs" in the March 1979 edition of "Electrical World." His article on "Standby Electric Rates" was published in the November 8, 1984 issue of "Public Utilities Fortnightly." In February of 1984, he completed a detailed analysis entitled "Load Data Transfer Techniques" on behalf of the Electric Power Research Institute, which published the study.

Mr. Baron has presented testimony as an expert witness in Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Maryland, Missouri, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Texas, Utah, Virginia, West Virginia, Wisconsin, Wyoming, the Federal Energy Regulatory Commission and in United States Bankruptcy Court. A list of his specific regulatory appearances follows.

**Expert Testimony Appearances
of
Stephen J. Baron
As of September 2014**

Date	Case	Jurisdict.	Party	Utility	Subject
4/81	203(B)	KY	Louisville Gas & Electric Co.	Louisville Gas & Electric Co.	Cost-of-service.
4/81	ER-81-42	MO	Kansas City Power & Light Co.	Kansas City Power & Light Co.	Forecasting.
6/81	U-1933	AZ	Arizona Corporation Commission	Tucson Electric Co.	Forecasting planning.
2/84	8924	KY	Airco Carbide	Louisville Gas & Electric Co.	Revenue requirements, cost-of-service, forecasting, weather normalization.
3/84	84-038-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Excess capacity, cost-of-service, rate design.
5/84	830470-EI	FL	Florida Industrial Power Users' Group	Florida Power Corp.	Allocation of fixed costs, load and capacity balance, and reserve margin. Diversification of utility.
10/84	84-199-U	AR	Arkansas Electric Energy Consumers	Arkansas Power and Light Co.	Cost allocation and rate design.
11/84	R-842651	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Interruptible rates, excess capacity, and phase-in.
1/85	85-65	ME	Airco Industrial Gases	Central Maine Power Co.	Interruptible rate design.
2/85	I-840381	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Load and energy forecast.
3/85	9243	KY	Alcan Aluminum Corp., et al.	Louisville Gas & Electric Co.	Economics of completing fossil generating unit.
3/85	3498-U	GA	Attorney General	Georgia Power Co.	Load and energy forecasting, generation planning economics.
3/85	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
5/85	84-249	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design return multipliers.
5/85		City of Santa Clara	Chamber of Commerce	Santa Clara Municipal	Cost-of-service, rate design.

Expert Testimony Appearances
of
Stephen J. Baron
As of September 2014

Date	Case	Jurisdict.	Party	Utility	Subject
6/85	84-768-E-42T	WV	West Virginia Industrial Intervenors	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
6/85	E-7 Sub 391	NC	Carolina Industrials (CIGFUR III)	Duke Power Co.	Cost-of-service, rate design, interruptible rate design.
7/85	29046	NY	Industrial Energy Users Association	Orange and Rockland Utilities	Cost-of-service, rate design.
10/85	85-043-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Regulatory policy, gas cost-of-service, rate design.
10/85	85-63	ME	Airco Industrial Gases	Central Maine Power Co.	Feasibility of interruptible rates, avoided cost.
2/85	ER-8507698	NJ	Air Products and Chemicals	Jersey Central Power & Light Co.	Rate design.
3/85	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve, prudence, off-system sales guarantee plan.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve margins, prudence, off-system sales guarantee plan.
3/86	85-299U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design, revenue distribution.
3/86	85-726-EL-AIR	OH	Industrial Electric Consumers Group	Ohio Power Co.	Cost-of-service, rate design, interruptible rates.
5/86	86-081-E-GI	WV	West Virginia Energy Users Group	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
8/86	E-7 Sub 408	NC	Carolina Industrial Energy Consumers	Duke Power Co.	Cost-of-service, rate design, interruptible rates.
10/86	U-17378	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Excess capacity, economic analysis of purchased power.
12/86	38063	IN	Industrial Energy Consumers	Indiana & Michigan Power Co.	Interruptible rates.

Expert Testimony Appearances
of
Stephen J. Baron
As of September 2014

Date	Case	Jurisdict.	Party	Utility	Subject
3/87	EL-86-53-001 EL-86-57-001	Federal Energy Regulatory Commission (FERC)	Louisiana Public Service Commission Staff	Gulf States Utilities, Southern Co.	Cost/benefit analysis of unit power sales contract.
4/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Load forecasting and imprudence damages, River Bend Nuclear unit.
5/87	87-023-E-C	WV	Airco Industrial Gases	Monongahela Power Co.	Interruptible rates.
5/87	87-072-E-G1	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Analyze Mon Power's fuel filing and examine the reasonableness of MP's claims.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic dispatching of pumped storage hydro unit.
5/87	9781	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Analysis of impact of 1986 Tax Reform Act.
6/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Economic prudence, evaluation of Vogtle nuclear unit - load forecasting, planning.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in plan for River Bend Nuclear unit.
7/87	85-10-22	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Methodology for refunding rate moderation fund.
8/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Test year sales and revenue forecast.
9/87	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Excess capacity, reliability of generating system.
10/87	R-870651	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Interruptible rate, cost-of-service, revenue allocation, rate design.
10/87	I-860025	PA	Pennsylvania Industrial Intervenors		Proposed rules for cogeneration, avoided cost, rate recovery.
10/87	E-015/	MN	Taconite	Minnesota Power	Excess capacity, power and

Expert Testimony Appearances
of
Stephen J. Baron
As of September 2014

Date	Case	Jurisdict.	Party	Utility	Subject
	GR-87-223		Intervenors	& Light Co.	cost-of-service, rate design.
10/87	8702-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue forecasting, weather normalization.
12/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light Power Co.	Excess capacity, nuclear plant phase-in.
3/88	10064	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Revenue forecast, weather normalization rate treatment of cancelled plant.
3/88	87-183-TF	AR	Arkansas Electric Consumers	Arkansas Power & Light Co.	Standby/backup electric rates.
5/88	870171C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
6/88	870172C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
7/88	88-171-EL-AIR 88-170-EL-AIR Interim Rate Case	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison	Financial analysis/need for interim rate relief.
7/88	Appeal of PSC	19th Judicial Docket U-17282	Louisiana Public Service Commission Circuit Court of Louisiana	Gulf States Utilities	Load forecasting, imprudence damages.
11/88	R-880989	PA	United States Steel	Carnegie Gas	Gas cost-of-service, rate design.
11/88	88-171-EL-AIR 88-170-EL-AIR	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison. General Rate Case.	Weather normalization of peak loads, excess capacity, regulatory policy.
3/89	870216/283 284/286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Calculated avoided capacity, recovery of capacity payments.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cost-of-service, rate design.

**Expert Testimony Appearances
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Stephen J. Baron
As of September 2014**

Date	Case	Jurisdict.	Party	Utility	Subject
8/89	3840-U	GA	Georgia Public Service Commission	Georgia Power Co.	Revenue forecasting, weather normalization.
9/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Prudence - Palo Verde Nuclear Units 1, 2 and 3, load forecasting.
10/89	2262	NM	New Mexico Industrial Energy Consumers	Public Service Co. of New Mexico	Fuel adjustment clause, off-system sales, cost-of-service, rate design, marginal cost.
11/89	38728	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Excess capacity, capacity equalization, jurisdictional cost allocation, rate design, interruptible rates.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Jurisdictional cost allocation, O&M expense analysis.
5/90	890366	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Non-utility generator cost recovery.
6/90	R-901609	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Allocation of QF demand charges in the fuel cost, cost-of-service, rate design.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost-of-service, rate design, revenue allocation.
12/90	U-9346 Rebuttal	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Demand-side management, environmental externalities.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, jurisdictional allocation.
12/90	90-205	ME	Airco Industrial Gases	Central Maine Power Co.	Investigation into interruptible service and rates.
1/91	90-12-03 Interim	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Interim rate relief, financial analysis, class revenue allocation.
5/91	90-12-03 Phase II	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Revenue requirements, cost-of-service, rate design, demand-side management.

Expert Testimony Appearances
of
Stephen J. Baron
As of September 2014

Date	Case	Jurisdict.	Party	Utility	Subject
8/91	E-7, SUB SUB 487	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Revenue requirements, cost allocation, rate design, demand-side management.
8/91	8341 Phase I	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, rate design, 1990 Clean Air Act Amendments.
8/91	91-372 EL-UNC	OH	Armco Steel Co., L.P.	Cincinnati Gas & Electric Co.	Economic analysis of cogeneration, avoid cost rate.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
9/91	91-231 -E-NC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	8341 - Phase II	MD	Westvaco Corp.	Potomac Edison Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Results of comprehensive management audit.
Note: No testimony was prefiled on this.					
11/91	U-17949 Subdocket A	LA	Louisiana Public Service Commission Staff	South Central Bell Telephone Co. and proposed merger with Southern Bell Telephone Co.	Analysis of South Central Bell's restructuring and
12/91	91-410-EL-AIR	OH	Armco Steel Co., Air Products & Chemicals, Inc.	Cincinnati Gas & Electric Co.	Rate design, interruptible rates.
12/91	P-880286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Evaluation of appropriate avoided capacity costs - QF projects.
1/92	C-913424	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Industrial interruptible rate.
6/92	92-02-19	CT	Connecticut Industrial Energy Consumers	Yankee Gas Co.	Rate design.

Expert Testimony Appearances
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Stephen J. Baron
As of September 2014

Date	Case	Jurisdict.	Party	Utility	Subject
8/92	2437	NM	New Mexico Industrial Intervenors	Public Service Co. of New Mexico	Cost-of-service.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cost-of-service, rate design, energy cost rate.
9/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
10/92	M-00920312 C-007	PA	The GPU Industrial Intervenors	Pennsylvania Electric Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
12/92	U-17949	LA	Louisiana Public Service Commission Staff	South Central Bell Co.	Management audit.
12/92	R-00922378	PA	Armco Advanced Materials Co. The WPP Industrial Intervenors	West Penn Power Co.	Cost-of-service, rate design, energy cost rate, SO_2 allowance rate treatment.
1/93	8487	MD	The Maryland Industrial Group	Baltimore Gas & Electric Co.	Electric cost-of-service and rate design, gas rate design (flexible rates).
2/93	E002/GR-92-1185	MN	North Star Steel Co. Praxair, Inc.	Northern States Power Co.	Interruptible rates.
4/93	EC92 21000 ER92-806-000 (Rebuttal)	Federal Energy Regulatory Commission	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy agreement.	Merger of GSU into Entergy System; impact on system
7/93	93-0114-E-C	WV	Airco Gases	Monongahela Power Co.	Interruptible rates.
8/93	930759-EG	FL	Florida Industrial Power Users' Group	Generic - Electric Utilities	Cost recovery and allocation of DSM costs.
9/93	M-009 30406	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Ratemaking treatment of off-system sales revenues.
11/93	346	KY	Kentucky Industrial Utility Customers	Generic - Gas Utilities	Allocation of gas pipeline transition costs - FERC Order 636.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Nuclear plant prudence, forecasting, excess capacity.

Expert Testimony Appearances
of
Stephen J. Baron
As of September 2014

Date	Case	Jurisdict.	Party	Utility	Subject
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Cost allocation, rate design, rate phase-in plan.
5/94	U-20178	LA	Louisiana Public Service Commission	Louisiana Power & Light Co.	Analysis of least cost integrated resource plan and demand-side management program.
7/94	R-00942986	PA	Armco, Inc.; West Penn Power Industrial Intervenors	West Penn Power Co.	Cost-of-service, allocation of rate increase, rate design, emission allowance sales, and operations and maintenance expense.
7/94	94-0035-E-42T	WV	West Virginia Energy Users Group	Monongahela Power Co.	Cost-of-service, allocation of rate increase, and rate design.
8/94	EC94 13-000	Federal Energy Regulatory Commission	Louisiana Public Service Commission	Gulf States Utilities/Entergy	Analysis of extended reserve shutdown units and violation of system agreement by Entergy.
9/94	R-00943 081 R-00943 081C0001	PA	Lehigh Valley Power Committee	Pennsylvania Public Utility Commission	Analysis of interruptible rate terms and conditions, availability.
9/94	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Evaluation of appropriate avoided cost rate.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements.
10/94	5258-U	GA	Georgia Public Service Commission	Southern Bell Telephone & Telegraph Co.	Proposals to address competition in telecommunication markets.
11/94	EC94-7-000 ER94-898-000	FERC	Louisiana Public Service Commission	El Paso Electric and Central and Southwest	Merger economics, transmission equalization hold harmless proposals.
2/95	941-430EG	CO	CF&I Steel, L.P.	Public Service Company of Colorado	Interruptible rates, cost-of-service.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Cost-of-service, allocation of rate increase, rate design, interruptible rates.
6/95	C-00913424 C-00946104	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Interruptible rates.

**Expert Testimony Appearances
of
Stephen J. Baron
As of September 2014**

Date	Case	Jurisdict.	Party	Utility	Subject
8/95	ER95-112 -000	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Open Access Transmission Tariffs - Wholesale.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Company	Nuclear decommissioning, revenue requirements, capital structure.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	System Energy Resources, Inc.	Nuclear decommissioning, revenue requirements.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear decommissioning and cost of debt capital, capital structure.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Retail competition issues.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Revenue requirement analysis.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Elec. Co., Potomac Elec. Power Co., Constellation Energy Co.	Ratemaking issues associated with a Merger.
8/96	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
2/97	R-973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Competitive restructuring policy issues, stranded cost, transition charges.
6/97	Civil Action No. 94-11474	US Bank-ruptcy Court Middle District of Louisiana	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Confirmation of reorganization plan; analysis of rate paths produced by competing plans.
6/97	R-973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Retail competition issues, rate unbundling, stranded cost analysis.
6/97	8738	MD	Maryland Industrial Group	Generic	Retail competition issues

**Expert Testimony Appearances
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Stephen J. Baron
As of September 2014**

Date	Case	Jurisdict.	Party	Utility	Subject
7/97	R-973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big River Electric Corp.	Analysis of cost of service issues - Big Rivers Restructuring Plan
10/97	R-974008	PA	Metropolitan Edison Industrial Users	Metropolitan Edison Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	R-974009	PA	Pennsylvania Electric Industrial Customer	Pennsylvania Electric Co.	Retail competition issues, rate unbundling, stranded cost analysis.
11/97	U-22491	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
11/97	P-971265	PA	Philadelphia Area Industrial Energy Users Group	Enron Energy Services Power, Inc./ PECO Energy	Analysis of Retail Restructuring Proposal.
12/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Retail competition issues, rate unbundling, stranded cost analysis.
12/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
3/98 (Allocated Stranded Cost Issues)	U-22092	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Retail competition, stranded cost quantification.
3/98	U-22092		Louisiana Public Service Commission	Gulf States Utilities, Inc.	Stranded cost quantification, restructuring issues.
9/98	U-17735		Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Revenue requirements analysis, weather normalization.
12/98	8794	MD	Maryland Industrial Group and Millennium Inorganic Chemicals Inc.	Baltimore Gas and Electric Co.	Electric utility restructuring, stranded cost recovery, rate unbundling.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
5/99 (Cross-Answering Testimony)	EC-98-40-000	FERC	Louisiana Public Service Commission	American Electric Power Co. & Central South West Corp.	Merger issues related to market power mitigation proposals.

Expert Testimony Appearances
of
Stephen J. Baron
As of September 2014

Date	Case	Jurisdict.	Party	Utility	Subject
5/99 (Response Testimony)	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Performance based regulation, settlement proposal issues, cross-subsidies between electric. gas services.
6/99	98-0452	WV	West Virginia Energy Users Group	Appalachian Power, Monongahela Power, & Potomac Edison Companies	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	99-03-35	CT	Connecticut Industrial \Energy Consumers	United Illuminating Company	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	Adversary Proceeding No. 98-1065	U.S. Bankruptcy Court	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Motion to dissolve preliminary injunction.
7/99	99-03-06	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Electric utility restructuring, stranded cost recovery, rate unbundling.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
12/99	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Ananlysi of Proposed Contract Rates, Market Rates.
03/00	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Evaluation of Cooperative Power Contract Elections
03/00	99-1658-EL-ETP	OH	AK Steel Corporation	Cincinnati Gas & Electric Co.	Electric utility restructuring, stranded cost recovery, rate Unbundling.

Expert Testimony Appearances
of
Stephen J. Baron
As of September 2014

Date	Case	Jurisdict.	Party	Utility	Subject
08/00	98-0452 E-GI	WVA	West Virginia Energy Users Group	Appalachian Power Co. American Electric Co.	Electric utility restructuring rate unbundling.
08/00	00-1050 E-T 00-1051-E-T	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Electric utility restructuring rate unbundling.
10/00	SOAH 473-00-1020 PUC 2234	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges And Universities	TXU, Inc.	Electric utility restructuring rate unbundling.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, revenue requirements.
12/00	EL00-66-000 & ER00-2854 EL95-33-002	LA	Louisiana Public Service Commission	Entergy Services Inc.	Inter-Company System Agreement: Modifications for retail competition, interruptible load.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Addressing Contested Issues	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Jurisdictional Business Separation - Texas Restructuring Plan
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Test year revenue forecast.
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning requirements transmission revenues.
11/01	U-25965	LA	Louisiana Public Service Commission	Generic .	Independent Transmission Company ("Transco"). RTO rate design.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design, resource planning and demand side management.
06/02	U-25965	LA	Louisiana Public Service Commission	Entergy Gulf States Entergy Louisiana	RTO Issues
07/02	U-21453	LA	Louisiana Public Service Commission	SWEPCO, AEP	Jurisdictional Business Sep. - Texas Restructuring Plan.

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Date	Case	Jurisdict.	Party	Utility	Subject
08/02	U-25888	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services Inc. and the Entergy Operating Companies	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
11/02	02S-315EG	CO	CF&I Steel & Climax Molybdenum Co.	Public Service Co. of Colorado	Fuel Adjustment Clause
01/03	U-17735	LA	Louisiana Public Service Commission	Louisiana Coops	Contract Issues
02/03	02S-594E	CO	Cripple Creek and Victor Gold Mining Co.	Aquila, Inc.	Revenue requirements, purchased power.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Weather normalization, power purchase expenses, System Agreement expenses.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Tariff MSS-4.
11/03	ER03-583-000 ER03-583-001 ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001 ER03-682-002	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Market-Ing, L.P, and Entergy Power, Inc.	Evaluation of Wholesale Purchased Power Contracts.
12/03	U-27136	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc.	Evaluation of Wholesale Purchased Power Contracts.
01/04	E-01345-03-0437	AZ	Kroger Company	Arizona Public Service Co.	Revenue allocation rate design.
02/04	00032071	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Provider of last resort issues.
03/04	03A-436E	CO	CF&I Steel, LP and Climax Molybedenum	Public Service Company of Colorado	Purchased Power Adjustment Clause.

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Date	Case	Jurisdict.	Party	Utility	Subject
04/04	2003-00433 2003-00434	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service Rate Design
0-6/04	03S-539E	CO	Cripple Creek, Victor Gold Mining Co., Goodrich Corp., Holcim (U.S.,), Inc., and The Trane Co.	Aquila, Inc.	Cost of Service, Rate Design Interruptible Rates
06/04	R-00049255	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge.
10/04	04S-164E	CO	CF&I Steel Company, Climax Mines	Public Service Company of Colorado	Cost of service, rate design, Interruptible Rates.
03/05	Case No. 2004-00426 Case No. 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.
06/05	050045-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
07/05	U-28155	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Independent Coordinator of Transmission – Cost/Benefit
09/05	Case Nos. 05-0402-E-CN 05-0750-E-PC	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Environmental cost recovery, Securitization, Financing Order
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission expenses. Congestion Cost Recovery Mechanism
03/06	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.
04/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	Transmission Prudence Investigation
06/06	R-00061346 C0001-0005	PA	Duquesne Industrial Intervenors & IECPA	Duquesne Light Co.	Cost of Service, Rate Design, Transmission Service Charge, Tariff Issues
06/06	R-00061366 R-00061367 P-00062213 P-00062214		Met-Ed Industrial Energy Users Group and Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Generation Rate Cap, Transmission Service Charge, Cost of Service, Rate Design, Tariff Issues
07/06	U-22092 Sub-J	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.

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Date	Case	Jurisdict.	Party	Utility	Subject
07/06	Case No. 2006-00130 Case No. 2006-00129	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.
08/06	Case No. PUE-2006-00065	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Allocation of Rev Incr, Off-System Sales margin rate treatment
09/06	E-01345A-05-0816	AZ	Kroger Company	Arizona Public Service Co.	Revenue alllocation, cost of service, rate design.
11/06	Doc. No. 97-01-15RE02	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power United Illuminating	Rate unbundling issues.
01/07	Case No. 06-0960-E-42T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Retail Cost of Service Revenue apportionment
03/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	Implementation of FERC Decision Jurisdictional & Rate Class Allocation
05/07	Case No. 07-63-EL-UNC	OH	Ohio Energy Group	Ohio Power, Columbus Southern Power	Environmental Surcharge Rate Design
05/07	R-00049255 Remand	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge.
06/07	R-00072155	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues.
07/07	Doc. No. 07F-037E	CO	Gateway Canyons LLC	Grand Valley Power Coop.	Distribution Line Cost Allocation
09/07	Doc. No. 05-UR-103	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
11/07	ER07-682-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Schedule MSS-3. Cost functionalization issues.
1/08	Doc. No. 20000-277-ER-07	WY	Cimarex Energy Company	Rocky Mountain Power (PacifiCorp)	Vintage Pricing, Marginal Cost Pricing Projected Test Year
1/08	Case No. 07-551	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Class Cost of Service, Rate Restructuring, Apportionment of Revenue Increase to Rate Schedules
2/08	ER07-956	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Entergy's Compliance Filing System Agreement Bandwidth Calculations.
2/08	Doc No. P-00072342	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Default Service Plan issues.

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Date	Case	Jurisdict.	Party	Utility	Subject
3/08	Doc No. E-01933A-05-0650	AZ	Kroger Company	Tucson Electric Power Co.	Cost of Service, Rate Design
05/08	08-0278 E-GI	WV	West Virginia Energy Users Group	Appalachian Power Co. American Electric Power Co.	Expanded Net Energy Cost "ENEC" Analysis.
6/08	Case No. 08-124-EL-ATA	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Recovery of Deferred Fuel Cost
7/08	Docket No. 07-035-93	UT	Kroger Company	Rocky Mountain Power Co.	Cost of Service, Rate Design
08/08	Doc. No. 6680-UR-116	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
09/08	Doc. No. 6690-UR-119	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
09/08	Case No. 08-936-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Competitive Solicitation
09/08	Case No. 08-935-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Rate Plan
09/08	Case No. 08-917-EL-SSO 08-918-EL-SSO	OH	Ohio Energy Group	Ohio Power Company Columbus Southern Power Co.	Provider of Last Resort Rate Plan
10/08	2008-00251 2008-00252	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
11/08	08-1511 E-GI	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost "ENEC" Analysis.
11/08	M-2008-2036188, M-2008-2036197	PA	Met-Ed Industrial Energy Users Group and Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Transmission Service Charge
01/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Entergy's Compliance Filing System Agreement Bandwidth Calculations.
01/09	E-01345A-08-0172	AZ	Kroger Company	Arizona Public Service Co.	Cost of Service, Rate Design
02/09	2008-00409	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Cost of Service, Rate Design

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Date	Case	Jurisdict.	Party	Utility	Subject
5/09	PUE-2009 -00018	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Transmission Cost Recovery Rider
5/09	09-0177-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost "ENEC" Analysis
6/09	PUE-2009 -00016	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Fuel Cost Recovery Rider
6/09	PUE-2009 -00038	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Fuel Cost Recovery Rider
7/09	080677-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
8/09	U-20925 (RRF 2004)	LA	Louisiana Public Service Commission Staff	Entergy Louisiana LLC	Interruptible Rate Refund Settlement
9/09	09AL-299E	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Energy Cost Rate issues
9/09	Doc. No. 05-UR-104	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
9/09	Doc. No. 6680-UR-117	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
10/09	Docket No. 09-035-23	UT	Kroger Company	Rocky Mountain Power Co.	Cost of Service, Allocation of Rev Increase
10/09	09AL-299E	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Cost of Service, Rate Design
11/09	PUE-2009 -00019	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Cost of Service, Rate Design
11/09	09-1485 E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost "ENEC" Analysis.
12/09	Case No. 09-906-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Rate Plan
12/09	ER09-1224	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Entergy's Compliance Filing System Agreement Bandwidth Calculations.
12/09	Case No. PUE-2009-00030	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Allocation of Rev Increase, Rate Design

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Date	Case	Jurisdict.	Party	Utility	Subject
2/10	Docket No. 09-035-23	UT	Kroger Company	Rocky Mountain Power Co.	Rate Design
3/10	Case No. 09-1352-E-42T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Retail Cost of Service Revenue apportionment
3/10	E015/ GR-09-1151	MN	Large Power Intervenors	Minnesota Power Co.	Cost of Service, rate design
4/10	EL09-61	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to off-system sales
4/10	2009-00459	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission expenses.
4/10	2009-00548 2009-00549	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
7/10	R-2010-2161575	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Company	Cost of Service, Rate Design
09/10	2010-00167	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Cost of Service, Rate Design
09/10	10M-245E	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Economic Impact of Clean Air Act
11/10	10-0699-E-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Cost of Service, Rate Design, Transmission Rider
11/10	Doc. No. 4220-UR-116	WI	Wisconsin Industrial Energy Group, Inc.	Northern States Power Co. Wisconsin	Cost of Service, rate design
12/10	10A-554EG	CO	CF&I Steel Company Climax Molybdenum	Public Service Company	Demand Side Management Issues
12/10	10-2586-EL-SSO	OH	Ohio Energy Group	Duke Energy Ohio	Provider of Last Resort Rate Plan Electric Security Plan
3/11	20000-384-ER-10	WY	Wyoming Industrial Energy Consumers	Rocky Mountain Power Wyoming	Electric Cost of Service, Revenue Apportionment, Rate Design
5/11	2011-00036	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Cost of Service, Rate Design
6/11	Docket No. 10-035-124	UT	Kroger Company	Rocky Mountain Power Co.	Class Cost of Service
6/11	PUE-2011-00045	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Fuel Cost Recovery Rider

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Date	Case	Jurisdict.	Party	Utility	Subject
07/11	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	Entergy System Agreement - Successor Agreement, Revisions, RTO Day 2 Market Issues
07/11	Case Nos. 11-346-EL-SSO 11-348-EL-SSO	OH	Ohio Energy Group	Ohio Power Company Columbus Southern Power Co.	Electric Security Rate Plan, Provider of Last Resort Issues
08/11	PUE-2011-00034	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Rate Recovery of RPS Costs
09/11	2011-00161 2011-00162	KY	Kentucky Industrial Utility	Louisville Gas & Electric Co. Kentucky Utilities Company	Environmental Cost Recovery
09/11	Case Nos. 11-346-EL-SSO 11-348-EL-SSO	OH	Ohio Energy Group	Ohio Power Company Columbus Southern Power Co.	Electric Security Rate Plan, Stipulation Support Testimony
10/11	11-0452 E-P-T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Energy Efficiency/Demand Reduction Cost Recovery
11/11	11-1272 E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost "ENEC" Analysis
11/11	E-01345A-11-0224	AZ	Kroger Company	Arizona Public Service Co.	Decoupling
12/11	E-01345A-11-0224	AZ	Kroger Company	Arizona Public Service Co.	Cost of Service, Rate Design
3/12	Case No. 2011-00401	KY	Kentucky Industrial Utility Consumers	Kentucky Power Company	Environmental Cost Recovery
4/12	2011-00036 Rehearing Case	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Cost of Service, Rate Design
5/12	2011-346 2011-348	OH	Ohio Energy Group	Ohio Power Company	Electric Security Rate Plan Interruptible Rate Issues
6/12	PUE-2012-00051	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Fuel Cost Recovery Rider
6/12	12-00012 12-00026	TN	Eastman Chemical Co. Air Products and Chemicals, Inc.	Kingsport Power Company	Demand Response Programs
6/12	Docket No. 11-035-200	UT	Kroger Company	Rocky Mountain Power Co.	Class Cost of Service
6/12	12-0275-E-GI-EE	WV	West Virginia Energy Users Group	Appalachian Power Company	Energy Efficiency Rider

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Date	Case	Jurisdict.	Party	Utility	Subject
6/12	12-0399-E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost ("ENEC")
7/12	120015-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
7/12	2011-00063	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Environmental Cost Recovery
8/12	Case No. 2012-00226	KY	Kentucky Industrial Utility Consumers	Kentucky Power Company	Real Time Pricing Tariff
9/12	ER12-1384	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement, Cancelled Plant Cost Treatment
9/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
11/12	12-1238 E-GI	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost Recovery Issues
12/12	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana	Purchased Power Contracts
12/12	EL09-61	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to off-system sales Damages Phase
12/12	E-01933A-12-0291	AZ	Kroger Company	Tucson Electric Power Co.	Decoupling
1/13	12-1188 E-PC	WV	West Virginia Energy Users Group	Appalachian Power Company	Securitization of ENEC Costs
1/13	E-01933A-12-0291	AZ	Kroger Company	Tucson Electric Power Co.	Cost of Service, Rate Design
4/13	12-1571 E-PC	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Generation Resource Transition Plan Issues
4/13	PUE-2012 -00141	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Generation Asset Transfer Issues
6/13	12-1655 E-PC	WV	West Virginia Energy Users Group	Appalachian Power Company	Generation Asset Transfer Issues
06/13	U-32675	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	MISO Joint Implementation Plan Issues

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Date	Case	Jurisdict.	Party	Utility	Subject
7/13	130040-EI	FL	WCF Health Utility Alliance	Tampa Electric Company	Cost of Service, Rate Design
7/13	13-0467-E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost ("ENEC")
7/13	13-0462-E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Energy Efficiency Issues
8/13	13-0557-E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Right-of-Way, Vegetation Control Cost Recovery Surcharge Issues
10/13	2013-00199	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Ratemaking Policy Associated with Rural Economic Reserve Funds
10/13	13-0764-E-CN	WV	West Virginia Energy Users Group	Appalachian Power Company	Rate Recovery Issues – Clinch River Gas Conversion Project
11/13	R-2013-2372129	PA	United States Steel Corporation	Duquesne Light Company	Cost of Service, Rate Design
11/13	13A-0686EG	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Demand Side Management Issues
11/13	13-1064-E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Right-of-Way, Vegetation Control Cost Recovery Surcharge Issues
4/14	ER-432-002	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to Union Pacific Railroad Litigation Settlement
5/14	2013-2385 2013-2386	OH	Ohio Energy Group	Ohio Power Company	Electric Security Rate Plan Interruptible Rate Issues
5/14	14-0344-E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost ("ENEC")
5/14	14-0345-E-PC	WV	West Virginia Energy Users Group	Appalachian Power Company	Energy Efficiency Issues
5/14	Docket No. 13-035-184	UT	Kroger Company	Rocky Mountain Power Co.	Class Cost of Service
7/14	PUE-2014-00007	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Renewable Portfolio Standard Rider Issues
7/14	ER13-2483	FERC	Bear Island Paper WB LLC	Old Dominion Electric Cooperative	Cost of Service, Rate Design Issues
8/14	14-0546-E-PC	WV	West Virginia Energy Users Group	Appalachian Power Company	Rate Recovery Issues – Mitchell Asset Transfer
8/14	PUE-2014-00026	VA	Old Dominion Committee	Appalachian Power Company	Biennial Review Case - Cost of Service Issues

BEFORE THE

PUBLIC UTILITY COMMISSION OF OHIO

In The Matter Of The Application Of Duke Energy Ohio, Inc. For Authority To Establish A Standard Service Offer Pursuant To Section 4928.143, Revised Code, In The Form Of An Electric Security Plan, Accounting Modifications And Tariffs For Generation Service	:	**Case No. 14-841-EL-SSO**
In The Matter Of The Application Of Duke Energy Ohio, Inc. For Authority To Amend Its Certified Supplier Tariff, P.U.C.O. No. 20	:	**Case No. 14-842-EL-ATA**

EXHIBIT_(SJB-2)

OF

STEPHEN J. BARON

ON BEHALF OF

THE OHIO ENERGY GROUP

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

September 2014

Resource Clearing Prices for all RPM Auctions held to date

	Capacity Product Type *	RTO	MAAC	MAAC + APS	EMAAC	SWMAAC	PS	PS NORTH	DPL SOUTH	PEPCO	ATSI	ATSI-CLEVELAND
DY 07/08												
BRA	*	$40.80	**	**	$197.67	$188.54	**	**	**	**	N/A	N/A
DY 08/09												
BRA	*	$111.92	**	**	$148.80	$210.11	**	**	**	**	N/A	N/A
3IA	*	$10.00	**	**	$10.00	$223.85	**	**	**	**	N/A	N/A
DY 09/10												
BRA	*	$102.04	**	$191.32	**	$237.33	**	**	**	**	N/A	N/A
3IA	*	$40.00	**	$86.00	**	**	**	**	**	**	N/A	N/A
DY 10/11												
BRA	*	$174.29	**	**	**	**	**	**	$186.12	**	N/A	N/A
3IA	*	$50.00	**	**	**	**	**	**	$50.00	**	N/A	N/A
DY 11/12												
BRA	*	$110.00	**	**	**	**	**	**	**	**	N/A	N/A
1IA	*	$55.00	**	**	**	**	**	**	**	**	N/A	N/A
3IA	*	$5.00	**	**	**	**	**	**	**	**	N/A	N/A
DY 12/13												
BRA	*	$16.46	$133.37	**	$139.73	$133.37	**	$185.00	$222.30	**	N/A	N/A
1IA	*	$16.46	$16.46	**	$153.67	$16.46	**	$153.67	$153.67	**	N/A	N/A
2IA	*	$13.01	$13.01	**	$48.91	$13.01	**	$48.91	$48.91	**	N/A	N/A
3IA	*	$2.51	$2.51	**	$2.51	$2.51	**	$2.51	$2.51	**	N/A	N/A
DY 13/14												
BRA	*	$27.73	$226.15	**	$245.00	$226.15	$245.00	$245.00	$245.00	$247.14	**	**
1IA	*	$20.00	$20.00	**	$178.85	$54.82	$178.85	$178.85	$178.85	$54.82	**	**
2IA	*	$7.01	$10.00	**	$40.00	$10.00	$40.00	$40.00	$40.00	$10.00	**	**
3IA	*	$4.05	$30.00	**	$188.44	$30.00	$188.44	$188.44	$188.44	$30.00	**	**
DY 14/15												
BRA	Annual	$125.99	$136.50	**	$136.50	$136.50	$136.50	$225.00	$136.50	$136.50	**	**
BRA	Ext Summer	$125.99	$136.50	**	$136.50	$136.50	$136.50	$225.00	$136.50	$136.50	**	**
BRA	Limited	$125.47	$125.47	**	$125.47	$125.47	$125.47	$213.97	$125.47	$125.47	**	**
1IA	Annual	$5.54	$16.56	**	$16.56	$16.56	$16.56	$410.95	$16.56	$16.56	**	**
1IA	Ext Summer	$5.54	$16.56	**	$16.56	$16.56	$16.56	$410.95	$16.56	$16.56	**	**
1IA	Limited	$0.03	$5.23	**	$5.23	$5.23	$5.23	$399.62	$5.23	$5.23	**	**

Resource Clearing Prices for all RPM Auctions held to date

	Capacity Product Type *	RTO	MAAC	MAAC + APS	EMAAC	SWMAAC	PS	PS NORTH	DPL SOUTH	PEPCO	ATSI	ATSI-CLEVELAND
2IA	Annual	$25.00	$56.94	**	$56.94	$56.94	$56.94	$310.00	$56.94	$56.94	**	**
2IA	Ext Summer	$25.00	$56.94	**	$56.94	$56.94	$56.94	$310.00	$56.94	$56.94	**	**
2IA	Limited	$25.00	$56.94	**	$56.94	$56.94	$56.94	$310.00	$56.94	$56.94	**	**
3IA	Annual	$25.51	$132.20	**	$132.20	$132.20	$132.20	$256.76	$132.20	$132.20	**	**
3IA	Ext Summer	$25.51	$132.20	**	$132.20	$132.20	$132.20	$256.76	$132.20	$132.20	**	**
3IA	Limited	$25.51	$132.20	**	$132.20	$132.20	$132.20	$256.76	$132.20	$132.20	**	**

DY 15/16

BRA	Annual	$136.00	$167.46	**	$167.46	$167.46	$167.46	$167.46	$167.46	$167.46	$357.00	**
BRA	Ext Summer	$136.00	$167.46	**	$167.46	$167.46	$167.46	$167.46	$167.46	$167.46	$322.08	**
BRA	Limited	$118.54	$150.00	**	$150.00	$150.00	$150.00	$150.00	$150.00	$150.00	$304.62	**
1IA	Annual	$43.00	$111.00	**	$111.00	$111.00	$122.95	$122.95	$111.00	$111.00	$168.37	**
1IA	Ext Summer	$43.00	$111.00	**	$111.00	$111.00	$122.95	$122.95	$111.00	$111.00	$168.37	**
1IA	Limited	$43.00	$111.00	**	$111.00	$111.00	$122.95	$122.95	$111.00	$111.00	$168.37	**
2IA	Annual	$136.00	$153.56	**	$153.56	$153.56	$167.46	$167.46	$153.56	$153.56	$216.54	**
2IA	Ext Summer	$136.00	$153.56	**	$153.56	$153.56	$167.46	$167.46	$153.56	$153.56	$216.54	**
2IA	Limited	$123.56	$141.12	**	$141.12	$141.12	$155.02	$155.02	$141.12	$141.12	$204.10	**

DY 16/17

BRA	Annual	$59.37	$119.13	**	$119.13	$119.13	$219.00	$219.00	$119.13	$119.13	$114.23	$114.23
BRA	Ext Summer	$59.37	$119.13	**	$119.13	$119.13	$219.00	$219.00	$119.13	$119.13	$114.23	$114.23
BRA	Limited	$59.37	$119.13	**	$119.13	$119.13	$219.00	$219.00	$119.13	$119.13	$94.45	$94.45

DY 17/18

BRA	Annual	$120.00	$120.00	**	$120.00	$120.00	$215.00	$215.00	$120.00	$120.00	$120.00	$120.00
BRA	Ext Summer	$120.00	$120.00	**	$120.00	$120.00	$215.00	$215.00	$120.00	$120.00	$120.00	$120.00
BRA	Limited	$106.02	$106.02	**	$106.02	$106.02	$201.02	$201.02	$106.02	$106.02	$106.02	$106.02

* The Annual, Extended Summer and Limited capacity product types were implemented starting with the 2014/2015 Delivery Year
** LDA was not modeled

BEFORE THE

PUBLIC UTILITY COMMISSION OF OHIO

In The Matter Of The Application Of Duke Energy Ohio, Inc. For Authority To Establish A Standard Service Offer Pursuant To Section 4928.143, Revised Code, In The Form Of An Electric Security Plan, Accounting Modifications And Tariffs For Generation Service	:	**Case No. 14-841-EL-SSO**
In The Matter Of The Application Of Duke Energy Ohio, Inc. For Authority To Amend Its Certified Supplier Tariff, P.U.C.O. No. 20	:	**Case No. 14-842-EL-ATA**

EXHIBIT_(SJB-3)

OF

STEPHEN J. BARON

ON BEHALF OF

THE OHIO ENERGY GROUP

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

September 2014

Article

Wednesday, September 17, 2014 5:22 PM ET Extra

DC Circuit refuses to grant en banc review of opinion overturning FERC demand response rule

By Glen Boshart

A federal appeals court has refused to grant en banc review of a decision by a three-judge panel of the same court remanding FERC's signature rule aimed at promoting the use of demand response — Order 745.

In a brief Sept. 17 order, the U.S. Court of Appeals for the District of Columbia Circuit simply said, "Respondent's petition for rehearing en banc, the response thereto, and the brief of amici curiae in support of respondent were circulated to the full court, and a vote was requested. Thereafter, a majority of the judges eligible to participate did not vote in favor of the petition. Upon consideration of the foregoing, it is ordered that the petition be denied."

The court's decision now means that FERC's only recourse is to ask the U.S. Supreme Court to review the D.C. Circuit's opinion, which the agency asserted "vacated a vital rule of national importance."

Issued in March 2011, Order 745 required ISOs and RTOs to pay demand response providers the full locational marginal price for energy whenever doing so is found to be cost-effective and when the demand resources have the capability of balancing supply and demand as an alternative to a generation resource. Commissioner Philip Moeller dissented from that order, arguing, among other things, that the majority should have allowed RTOs and ISOs to develop their own demand-compensation rules.

The Electric Power Supply Association and others took the matter to the D.C. Circuit, which on May 23 vacated the final rule in its entirety. Two of the judges on the court's three-member panel agreed with the petitioners that the FERC rule went too far because it encroached on the states' exclusive jurisdiction to regulate the retail market.

In contrast, the third judge on the panel issued a lengthy and adamant dissent insisting that demand response participation in wholesale markets and the ISOs' and RTOs' market rules concerning such participation "constitute 'practice[s] ... affecting' wholesale rates" that fall "squarely within FERC's jurisdiction."

The court ruling was seen as a devastating blow to former FERC Chairman Jon Wellinghoff's efforts to promote the use of demand response. But in seeking en banc review of the panel's opinion, FERC did not challenge the court's rulings with regard to the pricing aspects of Order 745. Instead, it focused on the finding that the commission improperly engaged in direct regulation of the retail market when it mandated that demand resources generally be paid the full market price for power.

The commission acknowledged "the rarity" of en banc rehearing but insisted that such review is appropriate here because the opinion "severely departs" from court precedent and Supreme Court guidance on where the line between federal and state authority over electricity regulation should fall. FERC further insisted that the majority's opinion "vastly expands the scope of authority reserved to the states."

In addition, the commission stressed that demand response is now well entrenched in the nation's wholesale electricity markets and that even a narrow reading of the court's opinion would have "significant consequences."

For instance, the commission warned that removing some or all demand response from wholesale markets could result in immediate shortfalls in planning reserves and create reliability issues, noting that supporters of its petition include not only demand response providers but also the PJM Interconnection LLC, industrial customers, environmental organizations and state regulatory authorities.

Commissioner Tony Clark, however, issued a statement at the same time that current Chairman Cheryl LaFleur announced FERC was going to seek en banc review saying that he found the D.C. Circuit's majority opinion persuasive with respect to the issue of FERC's jurisdiction over demand response.

Even the D.C. Circuit opinion denying en banc review involved some controversy. In a separate statement, Judge Laurence Silberman objected to a majority of the court agreeing to allow the Environmental Defense Fund, Natural Resources Defense Council and the Citizens Utility Board to file an amicus brief in support of the petition.

"Our rules explicitly say that no amicus briefs are to be submitted in support or opposition to a petition for rehearing en banc unless in response to our invitation. The movants, ignoring our rules, simply filed the brief accompanied by a motion for an invitation to file the brief. That technique makes a mockery of our rule; the motion is rather perfunctory when accompanying rather than preceding the actual brief. No party should be able to so blithely ignore our rules, but I doubt that such a technique is ever influential," the judge wrote.

In a statement issued shortly after the court's decision was posted, John Moore, senior attorney at the Sustainable FERC Project coalition housed within the Natural Resources Defense Council, said, "We're disappointed that the court preserved the broad sweep of its initial Order 745 decision because it will increase consumer costs and could frustrate some state compliance efforts with the EPA's proposal to curb power plant emissions." EPSA v. FERC (No. 11-1486 et al.)

BEFORE THE

PUBLIC UTILITY COMMISSION OF OHIO

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EXHIBIT_(SJB-4)

OF

STEPHEN J. BARON

ON BEHALF OF

THE OHIO ENERGY GROUP

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

September 2014

Article

Tuesday, January 07, 2014 5:16 PM ET Exclusive

Historic cold snap sets demand records, heightens grid operator concerns across Eastern US

By Esther Whieldon and Peter Marrin

With an extreme cold snap driving record winter electricity demand and the loss of some generating units, PJM Interconnection LLC, the New York ISO and the Midcontinent Independent System Operator Inc. on Jan. 7 were implementing emergency measures to maintain system reliability.

Meanwhile, despite the Electric Reliability Council of Texas Inc. potentially hitting a new winter record for energy usage of 57,277 MW on Jan. 7, the region discontinued a conservation alert that began the prior day.

In the Northeast, which is known for its winter reliability challenges, the ISO New England Inc. system was performing as expected, spokeswoman Ellen Foley said in a Jan. 7 interview. "We are in good shape" and experiencing energy consumption of about 20,860 MW, which is less than the region used during a cold spell in mid-December 2013, she said.

Nevertheless, ISO-NE has called for all generation and transmission asset operators to halt routine maintenance outages, if possible, so more generation will be available for New England's neighbors if they need it, Foley said.

Regarding PJM, "We are currently expected to be able to serve the load with some emergency procedures," Executive Vice President of Operations Mike Kormos said during a Jan. 7 media briefing. "We are seeing a large number of generator units that have either shut down or potentially may have problems due to the cold weather or the ability to get natural gas to those units later today as the gas system is ... stressed with the extreme cold weather."

Demand early Jan. 7 reached an all-time winter high of close to 138,600 MW, surpassing a previous winter peak of about 136,000 MW recorded in 2007, Kormos said. But electricity usage was anticipated to climb even higher — perhaps above 140,000 MW — between 3 p.m. and 7 p.m. ET as subzero temperatures cover much of the PJM footprint.

Going into the evening of Jan. 7, PJM was seeing about 36,600 MW of forced generation outages, or about 20% of its installed capacity, PJM spokeswoman Paula DuPont-Kidd said Jan. 7.

Kormos would not speculate on how many of the power plant outages were related to the cold weather but said the problems ranged from "mechanical problems potentially due to the cold weather to just normal [issues]."

"Generators do fail, particularly when we push them as hard as we've been pushing them," Kormos said. "We have tube breaks, normal breakage. We have had some fuel interruption on the natural gas system where units have not been able to get fuel. We have had units trying to convert to backup fuel that were potentially not successful in getting their units restarted. I'd say we've seen everything.

"These units are being asked to run for extremely long periods of time," Kormos said. "The units are breaking and in some cases we're getting them back as fast as they can fix them."

PJM began taking emergency steps late Jan. 6 and again early Jan. 7, including issuing a maximum generation alert, which calls on all capable generating units to be on call to ramp to full power if necessary. The grid operator late Jan. 6 also issued a 5% voltage reduction across the system, which is a measure to temporarily reduce voltage on the transmission system to reduce load but does not involve blackouts. Kormos said a 5% voltage reduction was not necessary early Jan. 7.

PJM on Jan. 6 obtained an emergency waiver from FERC to share nonpublic information with interstate natural gas pipelines to keep tabs on what fuel supplies are available and which gas-fired generators might be unavailable as a result. Kormos was not immediately available to indicate whether PJM has used those measures yet.

The challenge is that many gas-fired generators in PJM and nearby regions do not have firm contracts for gas supplies because there is no guarantee the RTO will call on them on a consistent basis throughout the year and no way to recover the costs of such contracts. That caused reliability issues in previous winters when gas utilities with residential heating customers gobbled up the capacity generators typically relied on in the secondary capacity release market.

PJM has also called on demand response customers to interrupt load and called for all customers to conserve electricity both early Jan. 6 and later, between 3 p.m. and 7 p.m. Kormos said about 1,900 MW of demand response was called on at about 6 a.m. on Jan. 7 but that the number could reach 3,000 MW later in the day as a new record-high load is challenged.

PJM is not alone in its efforts, Kormos said. Cold temperatures are taxing grid systems in the Midwest and along much of the Eastern Seaboard.

Article

PJM has bought emergency power from the NYISO area and has been supplying emergency power to areas in the Southeast such as North Carolina and South Carolina. "This particular cold is far-reaching and most of our neighbors are experiencing the extreme conditions that we are. ... Everybody is out there doing everything they can to help their neighbors, and we'll continue to do that," Kormos said.

PJM market prices highest in more than 5 years

In the electricity markets, the tight conditions sent real-time locational marginal prices well above $2,000/MWh early Jan. 7, while next-day deals done for Jan. 7 flows at PJM West averaged at $236.10/MWh, up 175% on the day and at highs not seen since June 2008, according to SNL Energy data.

For its part, NYISO called for the activation of voluntary demand response programs statewide and encouraged consumers to help conserve electricity between 4 p.m. and 10 p.m. The New York grid operator anticipated that electricity demand could even exceed the record winter peak of 25,541 MW set Dec. 20, 2004.

"The Northeast, Mid-Atlantic and Midwest regions are under significant stress, and we continue to work closely with system operators in all of our neighboring control areas to coordinate resources and support system reliability throughout the region," NYISO President and CEO Stephen Whitley said in a statement. "System conditions will be tight today with some generating units either not at full capacity or unavailable as a result of the extreme cold, icing conditions and high demand for natural gas."

In the Midwest, MISO on Jan. 6 hit a new winter peak usage of 109,300 MW, it said in a Jan. 7 news release. MISO issued a cold weather alert for the North, Central and some of its South regions from 10 p.m. ET Jan. 4 through that same time on Jan. 7.

"Severe weather conditions and very low temperatures moving across the MISO footprint over the last couple of days have had a significant impact on the supply and demand of electricity," MISO said. "The combination of elevated demand levels and power plants being forced offline create tight operating conditions, the effects of which include elevated wholesale power prices."

Meanwhile, natural gas spot markets in the Northeast reversed earlier gains even as pipelines issued a number of operational restriction orders.

Transcontinental Gas Pipe Line Co. LLC issued a systemwide imbalance operational flow order that included 23 locations in Zone 6 subject to the provisions of the OFO.

In addition, Spectra Energy Corp issued a number of critical notices due to issues on its Texas Eastern Transmission LP system. An OFO was issued due to an unplanned outage at the Delmont, Pa., compressor station, where repairs were underway. An OFO was also issued on TETCO's Philadelphia Lateral, and the company has also restricted interruptible nominations on the Leidy Line.

The Tennessee Valley Authority said its power system reached a preliminary peak power demand of 32,460 MW at 9 a.m. on Jan. 7, the second highest winter peak in TVA history behind the 32,572 MW winter peak reached on Jan. 16, 2009.

Jodi Shafto contributed to this article.

Thursday, January 16, 2014 5:19 PM ET Exclusive

Several surprising reliability issues emerged during recent cold snap, FERC told

By Glen Boshart

The recent extreme cold weather that hit most of the eastern half of the country for several days led to several surprising results, including a large amount of forced generating plant outages in the PJM Interconnection LLC that were caused by a lack of natural gas.

Briefing the agency during its Jan. 16 open monthly meeting on how the bulk power system performed during the recent polar vortex, FERC staff and a North American Electric Reliability Corp. official described several of those surprises. However, they warned that much of the information they have gathered thus far is preliminary and that it may take at least seven months before they reach any final conclusions.

The officials stressed that the cold weather during the event was the most severe and widespread to hit the Eastern Interconnection since the mid-1990s, which led to winter peak demand records being set in many areas. Actual system loads exceeded forecasts by approximately 7% in PJM and around 9% in Midcontinent Independent System Operator Inc.'s region.

Nevertheless, the officials said the bulk power system "remained stable and generally performed reliably" throughout the event. They praised utilities and grid operators for the actions they took to prepare for the cold weather, some of which were driven by the lessons learned from a widespread power outage that hit the Southwest in February 2011. The officials also cited PJM's efforts to obtain a waiver of certain nondisclosure provisions in its operating agreement, which it then used to help manage natural gas deliveries and supplies, as well as to confirm unit availability.

The cold weather also highlighted how dependent certain parts of the Midwest, Northeast and Southeast have become on natural gas as a generating fuel. The officials said it appears that all of those regions set record demands for natural gas, while other parts of the Eastern and Central U.S. were near their all-time peaks. While several gas pipelines curtailed interruptible or secondary firm transportation and storage services due to this record demand, staff said no firm supplies were interrupted.

The fuel restrictions stressed electric supply, but the officials said electric service remained mostly reliable, partially due to the gas-electric coordination procedures that were recently put into place and that "generally worked well" during the cold weather spell.

However, the officials said preliminary data indicates that forced power plant outages were significant in some regions, with the exact reasons why, including if they were weather-related, still uncertain.

It seems to be problematic that we had so many forced outages, Commissioner John Norris said in encouraging a thorough and accurate examination of the event.

Driving home that point, Mike Moon, senior director for reliability risk management at NERC, said at least 50 GW of forced generation outages were reported in the most severely impacted areas of the Eastern Interconnection on Jan. 6 and Jan. 7, which is higher than the historical wintertime average forced outage rate of 33 GW. Not all of the outages were due to weather either, he said, although the result and the reasons for it are still being studied.

Asked after the meeting whether she suspects that any of the outages may have been driven by attempts to manipulate markets, Acting Chairman Cheryl LaFleur said she had not heard of any reports or allegations that this may have been the case.

PJM hit hard

PJM, which was forced to direct member utilities to implement a 5% voltage reduction for about an hour and deploy demand response resources, was particularly hard hit by forced outages.

The grid operator reported in a Jan. 10 FERC filing that extreme cold weather drove demand levels to a new winter peak of around 141,000 MW. Making matters worse was that during the height of the event, on Jan. 8, roughly 40,000 MW of generating capacity was unavailable due to forced outages, more than double that experienced during each of three other cold weather events that have hit the region since January 2009.

Surprisingly, PJM also reported that a little more than 9,000 MW of the 40,000 MW of forced outages were due to gas curtailments. Moreover, during one evening peak, 33.4% of its forced outages were due to gas curtailments, meaning that 4.8% of its installed capacity was suddenly unavailable.

"As such, gas availability for power generation was tight over the entire footprint," PJM reported. However, it added that "the increased coordination and communication between the pipelines and PJM, and PJM and its generators, allowed PJM to manage the bulk power grid reliably."

Before the recent cold snap, the lack of gas supplies was of most concern to the ISO New England Inc. due to that region's heavy reliance on the fuel to generate power. However, adequate fuel supplies turned out not to be an issue in New England during the recent cold snap, perhaps because it did not come anywhere near record winter peak power demand levels, but appeared to have been one for PJM.

"I think it's fair to say that there may have been a few in PJM that didn't think this issue would affect them, but I think there's universal recognition now that this may be an issue for them as well," Commissioner Philip Moeller observed.

Asked after the meeting by a reporter whether she agreed that PJM may have been caught "somewhat off guard" that the lack of gas supplies was a problem for some of its generators, LaFleur recalled that just before the event PJM obtained a waiver to share info with pipelines, "so they clearly thought the cold snap would affect them." She also insisted that the grid was "bent [by] but did not break" because of the polar vortex.

Moeller suggested that one reason why that system performed well was that a joint report produced by FERC and NERC after the February 2011 Southwest outage "was not put on the shelf" and forgotten like previous reports that examined power outages. Instead, he insisted that the report's findings and recommendations were acted upon by many of the nation's utilities.

Moon was a little more cautious in his appraisal. "It is too soon to draw detailed comparisons of performance in 2011 versus last week or assess the extent to which entities avoided the particular mistakes of 2011, but in broad scope certainly the overall outcome was better, which suggests that the efforts made since 2011 have yielded a change for the better," he said.

Turning to the polar vortex's impact on energy prices, staff said on-peak average real-time power prices soared to as high as $765 per MWh in PJM and $510 per MWh in the New York ISO as natural gas prices and demand spiked upward. Prices in PJM rose to as high as $1,200 per MWh during one evening peak and reached an administratively set price of $1,800 per MWh for approximately 4 hours during one cold morning as emergency demand response was called on to perform.

Staff added that fuel oil had a $37 per MMBtu advantage over natural gas in New York and a $13 per MMBtu advantage in New England, allowing oil-fired and dual fuel units to run economically during the event.

Finally, while gas storage levels are down compared to those seen in recent years during mid-January, LaFleur said they are still more than twice as high as all-time lows for this time of the year and should be adequate until the gas storage refill season begins in April.

Article amended at 12:30 p.m. ET on Jan. 17, 2014, to clarify some of the commissioners' comments.

Friday, January 24, 2014 3:48 PM ET Extra

Outages highlight power grid pitfalls amid epic cold snap

By Peter Marrin

A high number of forced outages on power grids across the U.S. through January highlight the need for added measures to ensure reliability, including better weatherization of power plants and more economic incentives to run plants during times of extreme supply scarcity, according to a recent report from ICF International.

After skating "so close to the edge" during an outbreak of extreme cold in early January, the consultants emphasized that grid reliability "is closely related to generation profitability, and hence, commercial endeavors need to be properly structured based on anticipation of the market implications of reliability trends."

During the extreme "polar vortex" cold snap in early January, forced outages in PJM approached 40,000 MW, or 20% of PJM's total generating capacity. MISO lost 28,736 MW, or 22% of its total generation. But other ISOs saw much lower reported forced outage rates during the polar vortex. NYISO lost 4,135 MW of capacity, or around 10% of its installed capacity, close to its average outage rate. ISO-NE and ERCOT lost only around 5% of their total generation capacities due to forced outages during this period.

"A key driver for determination of the planning reserve margin target is the assumed forced outage rate by plant," ICF said. "Current planning assumes individual power plant outage rates are independent of one another. However, the evidence is clear that during extreme winter events, forced outages are not independent (i.e., individual plant outages are highly correlated in that they occur simultaneously), and to the extent PJM and other grid planners continue to make the standard assumption that outages are independent during extreme winter events (i.e., regardless of whether plant X is out, the probability plant Y is also out is unchanged), they are greatly understating the need for resources during the winter."

Weatherization, fuel procurement and the importance of price spikes

According to ICF, the failure of nearly 40 GW of PJM generation capacity on Jan. 8 highlights the need to provide more incentives for performance generally and especially during the winter.

"Up to 88 percent of forced outage capacity is from oil- and gas-fired generation — e.g., diesels, combustion turbines, steam/fossil (which can be coal or oil and natural gas), and combined cycles. This highlights the need for weatherization and other steps to provide for generation availability and appropriate fuel supply during extreme cold events," the report said.

Incentives such as high hourly energy prices and other market rules should be re-evaluated to ensure they are appropriate to meet the needs of the grid during times of high demand and forced outages, ICF said.

"U.S. policy on price spikes is very diverse and it is very unlikely that all of the prevailing approaches are appropriate. Rather, it is indicative of the need for greater attention to this critical tool for providing incentives for actual operation during critical periods."

During shortage events, ERCOT sets a $5,000/MWh level, PJM sets a $2,200/MWh level and ISO-NE sets a $1,000/MWh level.

"Price spikes allow the market to efficiently send signals that resources are needed," ICF noted. "Price caps are being raised in some markets, but in light of the critical need to ensure public health and safety, more attention is required on the impacts of energy market price caps on reliability. Thus, while some steps will alleviate the price increases (e.g., firm fuel supply and changes in the resource mix that favor availability year round as opposed to summer only), others may raise prices (e.g. raising the price cap during shortage events to ensure that power plants have the appropriate incentive to be available when needed, regardless of season and hour of the day). However, these changes are needed to prevent worse reliability problems during the next cold snap."

In addition, interruptible gas contracts need to be better accounted for or other measures need to be taken to account for fuel disruptions. While the natural gas pipelines were able to meet all their obligations to firm transportation customers during the cold snap in early January, no interruptible capacity was available due to the high level of firm demand, with up to one-third of the outages in PJM due to lack of gas delivery capability to generators that rely on interruptible capacity.

By comparison, ISO-NE experienced fewer than 1,500 MW of forced outages on Jan. 7 due to a lack of gas supplies. As a short-term solution to New England generators' lack of firm fuel supplies, ISO-NE in September 2013 procured nearly 2 million MWh for this winter from a combination of oil- and dual-fuel generators. In exchange for their commitment to maintain oil inventories needed to provide power when called upon, the selected oil- and dual-fuel generators receive monthly payments regardless of whether they are actually dispatched.

"This policy worked well for ISO-NE during the cold snap," the analysts said.

According to the ICF report, oil provided 25% of total generation across the entire ISO during the afternoon of Jan. 7, as units typically running on natural gas switched over to oil for a short period of time. By comparison, through the month of January so far, oil has provided only 7% of total generation in New England.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OHIO

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EXHIBIT_(SJB-5)

OF

STEPHEN J. BARON

ON BEHALF OF

THE OHIO ENERGY GROUP

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

September 2014

Thursday, August 21, 2014 4:07 PM ET Extra

PJM proposes new capacity performance product in wake of polar vortex

By Peter Marrin

In an effort to strengthen the definition of capacity resources to avoid a "potentially significant reliability issue," PJM Interconnection LLC has proposed a new product known as "capacity performance" for its Reliability Pricing Model forward capacity market, the grid operator announced in an Aug. 20 white paper.

Under the "PJM Capacity Performance Proposal," there would be four products: capacity performance; annual capacity, which will be renamed to base capacity; extended summer and limited demand response.

"The overall design objectives for the Capacity Performance product are to address the concerns highlighted in the [Aug. 1] PJM whitepaper including the observed generation performance issues, winter peak operations issues and the operational characteristics of resources that are needed to ensure that system reliability will be maintained throughout the current industry transformation and beyond," the Aug. 20 white paper states.

PJM said the new product would provide the grid with fuel security through a dependable fuel source, enhanced operational performance during peak periods, high availability of generation resources, flexible unit operational parameters and general operational diversity.

PJM said its capacity market has been "highly successful" in attracting more than 35,000 MW of new physical generation to the system since its inception in 2007. However, impacts from the major fuel switch that is occurring as coal generators retire and new natural gas generators replace them are "contributing to concerns about the performance of the generation fleet — particularly during extremely cold weather, like last January's."

At one point in early January 2014, up to 22% of PJM capacity was unavailable due to cold weather-related problems, which "highlighted a potentially significant reliability issue." According to its own estimates, PJM could fail to meet its peak load requirements in the winter of 2015/2016 if faced with a similar rate of generator outages, extreme cold and expected coal retirements.

Under the proposal, eligible resources for capacity performance will be generators capable of sustained, predictable operation for 16 hours per day for three consecutive days; annual demand response capable of sustained curtailment for 72 hours; and energy efficiency.

In its proposed structure, PJM also seeks to reinforce the existing definition of the annual capacity product "to ensure that the reliability of the grid will be maintained through the current industry fuel transition and beyond." Proposed changes to the requirements for the annual capacity product, which would rename the product to "base capacity," would eliminate many current restrictions on offers, define performance standards for peak periods and set penalties for not meeting them.

The proposal includes two cost-allocation options, including an extension of the existing method and a winter peak allocation option. Under the existing method, load-serving entries would continue to absorb the capacity costs in the form of locational reliability charges. Under the winter peak allocation method, the additional cost of the capacity performance product would be allocated based on zonal winter peak load forecasts.

PJM said the changes would have no immediate impact on the RTO's installed reserve margin, or IRM, calculation because "existing IRM calculations already assume higher capacity performance than is occurring, meaning that the new product should produce performance that already is factored in to the IRM calculation."

PJM hopes to make the changes in time for the May 2015 Base Residual Auction, with a transitional mechanism to address reliability requirements for delivery years 2015/16, 2016/17 and 2017/18.

A meeting to discuss the proposal is scheduled for Aug. 22, and stakeholder written comments are due Sept. 17. The "Enhanced Liaison Committee" process will begin in early October when PJM issues its final white paper with hopes to have the matter before the PJM board by early November.

This article was amended at 12:30 p.m. ET on Aug. 22, 2014, to clarify proposed changes to the "annual capacity," or "base capacity," product.
This article was amended at 5 p.m. ET on Aug. 22, 2014, to indicate stakeholder written comments are due Sept. 17.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OHIO

In The Matter Of The Application Of Duke Energy Ohio, Inc. For Authority To Establish A Standard Service Offer Pursuant To Section 4928.143, Revised Code, In The Form Of An Electric Security Plan, Accounting Modifications And Tariffs For Generation Service	:	**Case No. 14-841-EL-SSO**
In The Matter Of The Application Of Duke Energy Ohio, Inc. For Authority To Amend Its Certified Supplier Tariff, P.U.C.O. No. 20	:	**Case No. 14-842-EL-ATA**

EXHIBIT_(SJB-6)

OF

STEPHEN J. BARON

ON BEHALF OF

THE OHIO ENERGY GROUP

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

September 2014

Scheduled coal capacity retirements through 2022 (MW) by ISO/RTO

ISO/RTO	2014	2015	2016	2017	2018	2019	2020	2021	2022	Total
California Independent System Operator	342	-	-	255	-	-	585	-	-	1,182
Electric Reliability Council of Texas Inc.	-	-	-	-	840	-	-	-	-	840
ISO New England Inc.	150	-	-	1,133	-	-	-	-	-	1,283
Midcontinent Independent System Operator Inc.	-	800	1,016	-	-	-	-	-	-	1,816
PJM Interconnection LLC	2,179	8,252	165	1,205	-	-	-	-	-	11,801
Southwest Power Pool Inc	-	15	1,080	-	-	-	-	-	-	1,095
Outside of ISO/RTO	184	4,484	201	2,765	350	-	670	254	219	9,127
Total	**2,854**	**13,550**	**2,462**	**5,358**	**1,190**	**-**	**1,255**	**254**	**219**	**27,143**

- indicates a zero value
Includes only coal units for which there has been a firm retirement date reported between 2013 and 2022.
As of March 5, 2014.
Source: SNL Energy

Assessing the impact of announced retirements on ISOs and RTOs, the PJM Interconnection continues to be the operator that would be most affected, with 11,801 MW of coal capacity planned to be closed between March 2014 and 2022. PJM saw more than 2,700 MW of coal capacity retire in 2013, including FirstEnergy Corp.'s Hatfield's Ferry station, a 1,710-MW, supercritical coal plant in Greene County, Pa.

Other grid operators to be affected by retirements include MISO and ISO New England where 1,816 MW and 1,283 MW, respectively, of coal retirements have been announced between 2014 and 2022. CAISO and the Southwest Power Pool will also be impacted, with 1,182 MW and 1,095 MW, respectively, slated to be retired during the period. Approximately 9,127 MW of announced retirements during the period would occur outside an ISO.

10 largest companies with coal capacity retiring in 2014-2018

	Capacity retiring (MW)					
Company	2014	2015	2016	2017	2018	Total
American Electric Power Co. Inc.	630	4,943	988	-	-	6,561
Tennessee Valley Authority	113	1,271	-	1,744	-	3,128
NRG Energy Inc.	795	588	-	1,205	-	2,588
Southern Co.	-	1,953	201	-	-	2,154
Energy Capital Partners LLC	-	-	-	1,133	-	1,133
CMS Energy Corp.	-	-	958	-	-	958
Dominion Resources Inc.	-	932	-	-	-	932
FirstEnergy Corp.	641	244	-	-	-	885
CPS Energy	-	-	-	-	840	840
Duke Energy Corp.	-	761	-	-	-	761

- indicates a zero value
Includes only coal units for which the company has reported a firm retirement date between 2014 and 2018.
As of March 5, 2014.
Source: SNL Energy

On a company-specific level, AEP, the nation's largest coal burner, continues to have more coal unit retirements scheduled than any other generator by a significant margin. AEP has 6,561 MW of coal capacity scheduled to shut down between March 2014 and the end of 2018.

Other generators with a significant amount of retiring capacity during the 2014-2018 period include Tennessee Valley Authority, with 3,128 MW; NRG Energy, with 2,588 MW; Southern Co., with 2,154 MW; and Energy Capital Partners LLC, with 1,133 MW.

To view an updatable SNL template of coal unit retirement data, click here.

To find more details about U.S. power plants, go to SNL Energy's Power Plant Briefing Book Search.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OHIO

In The Matter Of The Application Of Duke Energy Ohio, Inc. For Authority To Establish A Standard Service Offer Pursuant To Section 4928.143, Revised Code, In The Form Of An Electric Security Plan, Accounting Modifications And Tariffs For Generation Service	:	**Case No. 14-841-EL-SSO**
In The Matter Of The Application Of Duke Energy Ohio, Inc. For Authority To Amend Its Certified Supplier Tariff, P.U.C.O. No. 20	:	**Case No. 14-842-EL-ATA**

EXHIBIT_(SJB-7)

OF

STEPHEN J. BARON

ON BEHALF OF

THE OHIO ENERGY GROUP

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

September 2014

Duke Energy Ohio
Case No. 14-841-EL-SSO, 14-842-EL-ATA
OEG Second Set Data Requests
Date Received: August 6, 2014

OEG-DR-02-008

REQUEST:

If Duke did not bid its interruptible load (as a CSP) into the 2017/2018 BRA, what options are now available to Duke's customers to participate in the PJM DR program for the 2017/2018 delivery year?

RESPONSE:

Objection. This Interrogatory seeks to elicit information that is irrelevant and not likely to lead to the discovery of admissible evidence. There is no proposal in these proceedings that concerns Duke Energy Ohio's participation in PJM's base residual auction for the 2017/2018 delivery year through the bidding in of demand response resources. Furthermore, the interruptible load program approved in Case No. 11-3549-EL-SSO expires, by its terms, on May 31, 2015. Additionally, a customer's options in respect of the PJM DR program are a matter of public record and thus equally accessible by the OEG. Without waiving said objection, to the extent discoverable, and in the spirit of discovery, customers can now participate indirectly, or directly, in PJM's DR program 2017/18 delivery year under one of several methods:

Indirectly, by participating with Duke Energy Ohio under the PowerShare® .

Indirectly, by participating with another CSP's DR program in the PJM 2017/18 Incremental Capacity Auctions.

Registering its DR resources with PJM and participating directly in the PJM 2017/18 Incremental Capacity Auctions.

PERSON RESPONSIBLE: As to objection - Legal
As to response - Richard A. Philip

BEFORE THE

PUBLIC UTILITY COMMISSION OF OHIO

In The Matter Of The Application Of Duke Energy Ohio, Inc. For Authority To Establish A Standard Service Offer Pursuant To Section 4928.143, Revised Code, In The Form Of An Electric Security Plan, Accounting Modifications And Tariffs For Generation Service	:	**Case No. 14-841-EL-SSO**
In The Matter Of The Application Of Duke Energy Ohio, Inc. For Authority To Amend Its Certified Supplier Tariff, P.U.C.O. No. 20	:	**Case No. 14-842-EL-ATA**

EXHIBIT_(SJB-8)

OF

STEPHEN J. BARON

ON BEHALF OF

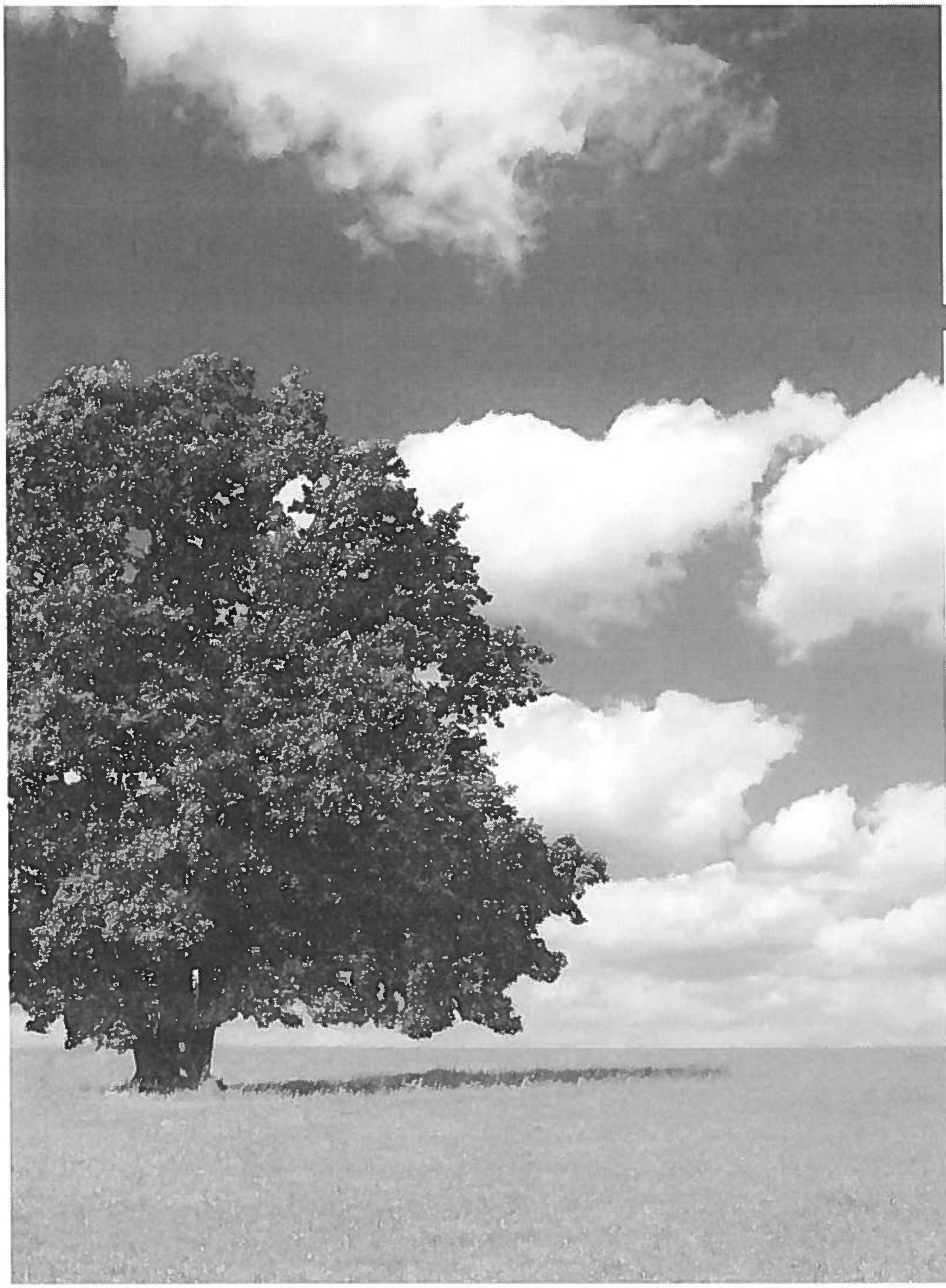
THE OHIO ENERGY GROUP

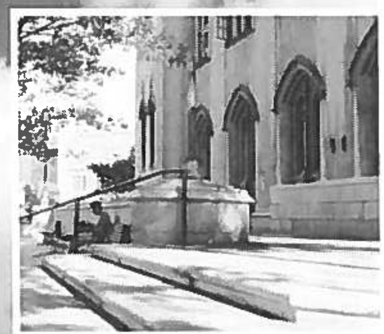
J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

September 2014

PowerShare®

DUKE ENERGY®





Ohio

2014 – 2015

PowerShare®: Profit from curtailing your energy use.

PowerShare is Duke Energy's demand-response program developed to reward your business for adjusting energy consumption levels during peak time periods.

One of the toughest challenges Duke Energy faces is balancing energy supply to meet our communities' growing needs. Building new generation facilities is costly, time-consuming and offers no immediate relief. Demand-response programs are the cheapest, fastest and cleanest way to meet energy demand, while providing our business customers with a way to profit from their energy curtailment.

Participation in PowerShare provides economic and environmental benefits:

- Offers cost incentives to business customers who effectively manage energy consumption.
- Helps customers reduce their energy usage, operating costs and carbon footprint.
- Helps maintain low energy rates by reducing the need for new generation plants.
- Mitigates electrical emergencies, increases system reliability and reduces customer inconvenience.
- Reduces the need to run expensive generation plants during high demand, resulting in lower wholesale market prices and end-user savings.
- Provides opportunity for customers to help shape future programs aligned to meet their business objectives.

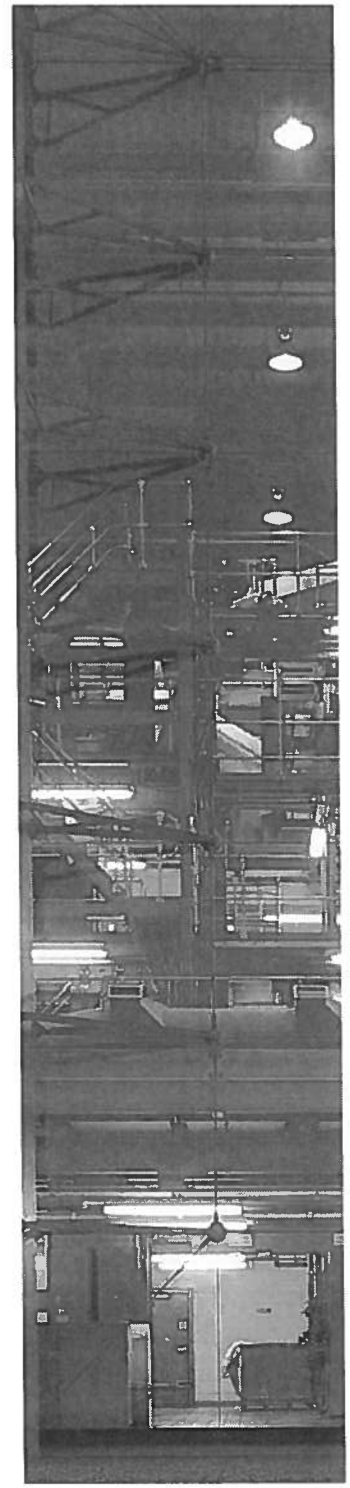
With PowerShare, you choose the options that best fit your company's operations.

Customers with contracts signed by Jan. 15, 2014, receive an additional $3/kilowatt (kW) incentive.

CallOption overview

The PowerShare CallOption program is ideal for customers who are able to reduce and maintain a predetermined electrical load during Emergency Curtailment periods. Participants receive Monthly Premium Credits, even if an Emergency event is not declared. Under the CallOption, participants:

- Must provide a minimum of 100 kilowatts (kW) of curtailable load.
- Are given a Monthly Premium Credit for the curtailable load made available.
- Agree to reduce and maintain load to a predetermined target level during Emergency events; target level is either the Firm Service Level specified in their contract or a fixed amount below their Proforma baseline.
- Are notified of events by email, office phone, cellphone and fax using Duke Energy's communication tool.
- Can choose the option to be a "Capacity Only" participant. This allows customers to contract with another provider to participate in the PJM energy markets.
- Can choose the option to be an "Emergency Full" participant, where Duke Energy Ohio would be the sole curtailment service provider.
- "Emergency Full" participants will receive 85 percent of Locational Marginal Price (LMP) as the event credit for Emergency events.
- "Emergency Full" participants are paid credits for energy curtailed in excess of the contractual commitment, up to 1,000 kilowatt-hours (kWh) for each hour of the event.



CallOption (continued)

CallOption Emergency

- Emergency Curtailment Periods are implemented when there are system capacity or reliability constraints. Duke Energy requires CallOption Emergency customers to reduce their loads during all Emergency Curtailment Periods.
- During Emergency Curtailment Periods, CallOption Emergency participants:
- Are given 90 minutes advance notice to reduce load prior to the event.
- May be required to curtail for up to six hours between noon and 8 p.m. on weekdays from June through September, excluding the holidays of Independence Day and Labor Day.
- Are required to participate in any Emergency Event declared by PJM; the maximum number of events is 10 per year.
- Are assessed Penalty Charges and loss of Monthly Premium Credit for failure to comply with Emergency Curtailment Period requirements.

All customers as part of their load reduction strategy will be required to meet all PJM testing requirements.

CallOption Emergency Curtailment Test

All participants are required to curtail load during a mandatory PJM Curtailment TEST each year. If a load reduction shortfalls from the contracted Option Load participants may be asked to re-test to conform to their contracted amount.

- The TEST Date for the 2014 - 2015 program year will be held Aug. 26, 2014, beginning at 4 p.m. and ending at 5 p.m.
- Load Reductions must be maintained for the entire test event hour.
- Fixed Reduction customers must reduce their contracted load below the Proforma to be in full compliance.
- Firm Service Level customers must curtail to their contracted firm service level.

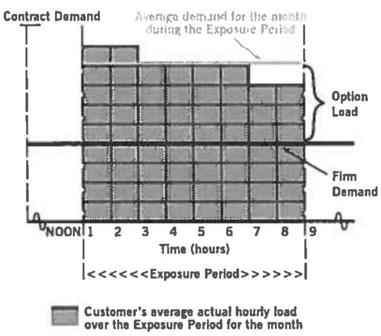
CallOption (continued)

Credits and penalties

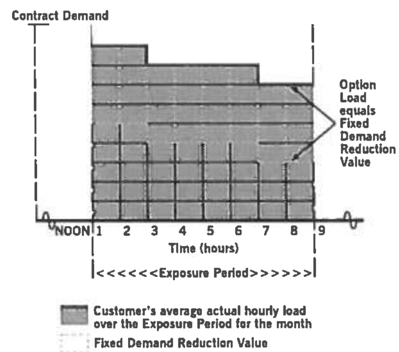
Duke Energy determines customers' Monthly Premium Credits by calculating the Option Load (curtailable load) available during the Exposure Period for each weekday of the month. The Exposure Period is from 1 p.m. to 7 p.m. June through September.

Load Reduction Credits are based on curtailed load down to 1,000 kilowatts per hour beyond the demand level specified in the customer's agreement.

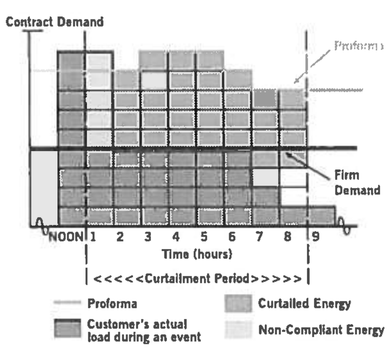
Calculation of Monthly Premium Credit for Firm Demand Option



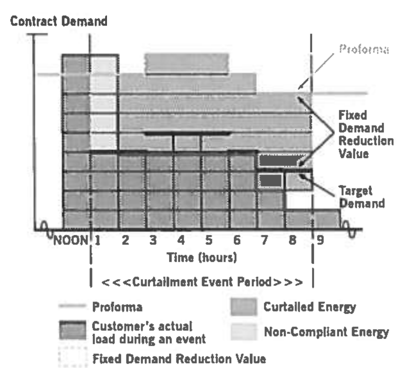
Calculation of Monthly Premium Credit for Fixed Demand Reduction Option

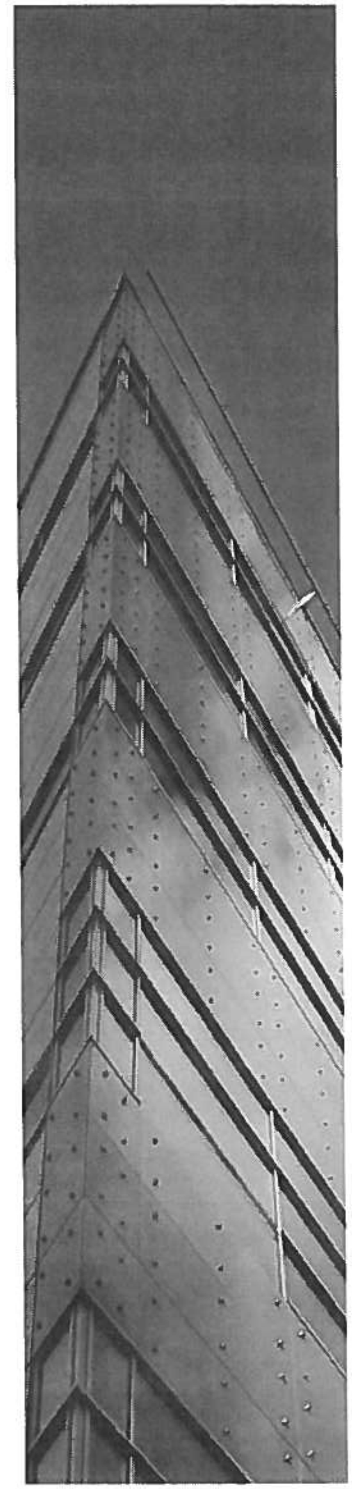


Calculation of Load Reduction Credits for Firm Demand Option



Calculation of Load Reduction Credits for Fixed Demand Reduction Option





PowerShare Reference and Comparison Chart

	CallOption Economic
Program Description	Customer agrees to curtail load to a contracted Firm Demand level or to the Proforma less Fixed Demand Reduction level during all Curtailment Periods.
Contract Term	1 year
Curtailment Minimums	Curtail a minimum of 100 kW
Monthly Capacity/ Premium Credit Rate	PS-0/10 $36/ kW / Year
Reason for Curtailment	For PJM capacity constraints only.
Number of Curtailment Periods	PS-0/10 10 events
Curtailment Period Times	Any weekday, noon to 8 p.m., limited to six hours per day, June – September.
Curtailment Period Notification Procedures	Advanced notification sent using office phone, cellphone, email and fax.
Penalty Charges	Penalty

Glossary of key terms

Capacity Credits or Monthly Premium Credits – Credits based on a potential or actual reduction in the facility's electrical demand. Calculation of the credit varies by Participation Option.

Curtail – Reduction of the electrical demand supplied by Duke Energy.

Curtailment Period – Period of time that a customer participating in a program is expected to curtail load.

Demand Response or Demand-Side Management – Widely accepted industry terms used to categorize the process of optimizing efficiencies through a form of energy management. Actions are required by the customer to change the amount or timing of consumption during periods specified by Duke Energy.

Emergency Curtailment Period or Event – Period of time that a customer participating in CallOption is called on and obligated to curtail load. The Event is declared by PJM when emergency conditions exist within that organization's footprint. Emergencies can be related but not limited to system electric constraints, generation outages or supply shortfalls.

Energy Credits or Load Reduction Credits – Compensatory incentive for reducing load during Curtailment Periods/Events.

Energy Profile Online (EPO) – Web-based software application that permits the viewing of usage and event information.

Exposure Period – Hours of overall peak demand during which curtailment is most likely. Exposure Period hours vary seasonally. Actual Curtailment Periods may occur outside of Exposure Periods.

Firm Demand – Portion of the Contract Demand that is not subject to interruption.

Fixed Demand Reduction – Portion of the Proforma Demand that the customer commits to curtail during Curtailment Periods.

Forecasted Demand or Proforma – Estimated hourly demand that a customer would normally exhibit, absent curtailment. The values are calculated using the customer's historical hourly meter data.

Non-Compliant Energy – Energy consumed during an Event that is above the Firm Demand or above the Proforma less the Fixed Demand Reduction value.

Option Load – Amount of available load eligible for Monthly Premium Credits under the Firm Service Level or Fixed Reduction options, which occur during the Exposure Period hours each month.

Penalty Charge – Charge for non-compliant energy used during Emergency Events.

PJM – The PJM Interconnection., which operates under an Open Access Transmission and Energy Markets Tariff filed with the Federal Energy Regulatory Commission.