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Via E-File

May 6, 2014

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

In re: Case Nos. 13-2385-EL-SSO and 13-2386-EL-AAM

Dear Sir/Madam:

Please find attached the DIRECT TESTIMONY AND EXHIBITS OF STEPHEN J. BARON and the DIRECT TESTIMONY AND PUBLIC EXHIBITS OF ALAN S. TAYLOR on behalf of the OHIO ENERGY GROUP for filing in the above-referenced matter.

The original and three (3) copies of the CONFIDENTIAL EXHIBIT to be filed under seal will follow by overnight mail. We are redacting this information pursuant to a Confidential Agreement filed with Ohio Power Company.

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

Respectfully yours,

Michael L. Kurtz

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

MLKkew
Encl.
Cc: Certificate of Service

CERTIFICATE OF SERVICE

I hereby certify that true copy of the foregoing was served by electronic mail (when available) or ordinary mail, unless otherwise noted, this 6th day of May, 2014 to the following:

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BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

In The Matter Of The Application Of Ohio Power Company For Authority To Establish A Standard Service Offer Pursuant To 4928.143, Ohio Rev. Code, In The Form Of An Electric Security Plan.	:	**Case No. 13-2385-EL-SSO**
In The Matter Of The Application Of Ohio Power Company For Approval Of Certain Accounting Authority.	:	**Case No. 13-2386-EL-AAM**

DIRECT TESTIMONY

OF

STEPHEN J. BARON

ON BEHALF OF

THE OHIO ENERGY GROUP

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

May 2014

BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

In The Matter Of The Application Of Ohio Power Company For Authority To Establish A Standard Service Offer Pursuant To 4928.143, Ohio Rev. Code, In The Form Of An Electric Security Plan.	:	**Case No. 13-2385-EL-SSO**
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TABLE OF CONTENTS

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 customer consumers throughout the United States. My educational background and professional experience are summarized on Baron Exhibit __ (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 Ohio Power Company ("AEP Ohio" or "the Company").

The members of OEG who take service from the Company are: AK Steel Corporation, ArcelorMittal, USA, E.I. duPont de Nemours and Company, Ford Motor Company, Linde, Inc., POET Biorefining, Praxair Inc., The Timken Company 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. 85-726-EL-AIR, 07-63-EL-UNC, 08-917-EL-SSO and 08-918-EL-SSO (the Company's 2008 initial ESP cases) and in 11-0346-EL-SSO, the Company's 2011 ESP case. I have also testified in numerous AEP cases in Kentucky, West Virginia, Virginia, Louisiana, Indiana and before the FERC.

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 and Market Rate Offer cases involving the FirstEnergy Companies and Duke Energy Ohio, in addition to the AEP cases cited above. These include Case Nos. 08-935-EL-SSO, 08-936-EL-SSO, 09-906-EL-SSO and 10-2586-EL-SSO.

Q. What is the purpose of your testimony?

A. I discuss a number of issues associated with the Company's proposed Electric Security Plan III ("ESP III"). Specifically, I will address three issues: 1) the reasonableness of the Company's overall proposal, including proposed new riders, 2) the proposal to eliminate the existing AEP Ohio interruptible rate (Rider IRP-D), and 3) the proposal to recover deferred capacity costs through the existing Rate Stability Rider ("RSR"). While the Company states that it will file a separate application to recover the deferred capacity charges through the RSR, Company witness William Allen addresses this issue in his testimony in this case.

Q. Would you please summarize your testimony and recommendations?

A. Yes. Generally, my testimony supports AEP Ohio's proposed ESP III plan, with two specific adjustments. The first adjustment concerns the Company's proposal to terminate interruptible Rider IRP-D at the end of the current ESP (May 2015). Currently Rider IRP-D provides participating interruptible customers with an interruptible credit of $8.21/kW-month. AEP Ohio argues that because it is divesting most of its owned generation resources, it should no longer offer customers an interruptible load demand response program through Rider IRP-D. As I discuss in my testimony, both First Energy ("FE") and Duke Energy Ohio ("Duke") offer interruptible credits to participating customers in Ohio. FE divested its generation resources a number of years ago and Duke is in the process of divesting its generation. It would be inconsistent with this prior Commission policy to allow AEP Ohio to terminate its interruptible load program. Moreover, the continuation of the Company's interruptible load program for large industrial customers will contribute to overall power system reliability in Ohio. OEG recommends that the Commission authorize AEP Ohio to continue an interruptible rate program using two optional interruptible rates. The first option would be based on the approach approved by the Commission for Duke; the second would be an option based on a modified version of the current IRP-D rider.

The second adjustment that I support, concerns the proposed recovery of deferred capacity charges through the RSR. Though the Company is not formally requesting approval of its proposal for such RSR recovery in this case, AEP witness Allen has discussed this issue and it is therefore appropriate for OEG to respond in this case. As I will discuss, OEG believes that it is important to consider this issue as part of the overall Commission evaluation of the ESP III plan. While OEG does not oppose the Company's deferred capacity cost proposal, I recommend that customers who are currently taking service from AEP Ohio pursuant to a Reasonable Arrangement ("RA") approved by the Commission be excluded in whole or in part from the proposed RSR charge in ESP III. RA customers have been authorized to receive certain reduced charges from the Company's standard tariff rates due to competitive, economic development or other criteria found by the Commission to justify such discounts. OEG recommends that the deferred capacity charge recovery through the RSR charge, beginning June 2015, not apply to load subject to a Reasonable Arrangement. Even with the exclusion of these customers, the Company would still likely recover its deferred costs over the 36 month term of ESP III. If not, the Company could recover any remaining unrecovered amounts in the next ESP.

II. REASONABLENESS OF AEP OHIO'S PROPOSED ESP III PLAN

Q. Before addressing the two specific issues that you have identified with the Company's ESP III proposal (the IRP-D termination and the deferred capacity cost recovery through the RSR), would you discuss your general evaluation of the plan?

A. Yes. OEG does not object to the Company's ESP III proposal, with the exceptions that I discuss below regarding rider IRP-D and the recovery of deferred capacity costs. Specifically, OEG does not object to the Company's proposed new riders, the general methodologies proposed to allocate rider costs to rate schedules and the SSO auction protocols. OEG witness Alan Taylor addresses the Company's proposal to retain its OVEC capacity in his testimony.

Q. On page 8 of his direct testimony, AEP witness William Allen discusses the Company's proposal for a PPA rider that would initially include OVEC net revenues or costs as a hedge against market volatility for all customers. Do you have any specific comments on this proposal?

A. As I indicated, OEG witness Alan Taylor provides specific testimony regarding the Company's OVEC proposal on behalf of OEG. However, as discussed by Mr. Taylor, OEG generally supports the conceptual proposal to provide cost-based hedges to mitigate market volatility for both SSO and shopping customers using physical capacity resources. Based on Mr. Allen's testimony, the Company's proposal is an initial proposal to include OVEC net revenues (positive or negative relative to the market) in the PPA rider, but specifically reserved the right to include other resources in the PPA rider during the term of the ESP, if the AEP proposal is approved.

Q. Notwithstanding any specific OEG recommendations regarding the PPA rider discussed by OEG witness Taylor, do you believe that an expanded cost-based hedge through additional PPA resources could be beneficial to AEP Ohio customers?

A. Yes. I believe that there can be potential benefits to customers from an expanded cost-based hedge using physical capacity along the lines of the Company's OVEC proposal. While the potential benefits would depend on the specific resource(s) that might be included in an expanded hedging portfolio, such a proposal has the potential to provide customers additional price stability over the term of the ESP. In addition, such a portfolio could form the basis for cost of service contract rates for customers that desire more stable pricing.

Q. Do you agree with the Company's proposal to allocate the costs associated with many of the riders using rate schedule base distribution revenues?

A. Yes. The Commission has previously approved this allocation methodology for a number of the Company's riders in its Order in the ESP II case (11-0346-EL-SSO) and it is reasonable to follow this approach for the new and/or modified existing riders proposed by AEP Ohio in this case.

The Company is proposing to allocate the following new and/or modified riders using base distribution revenues:

1. Distribution Investment Rider ("DIR")
2. Sustained and Skilled Workforce Rider ("SSWR")
3. Storm Damage Recovery Rider ("SDRR")
4. Enhanced Service Reliability Rider ("ESRR")

As discussed in the Company's responses to Office of Consumers' Council ("OCC") data requests OCC 7-116, 117, 119, 120, 122 and 126, the costs underlying these riders are related to the provision of distribution service and it is therefore reasonable to allocate them to rate schedules on the basis of distribution revenues. Baron Exhibit__(SJB-2) contains the response to OCC 7-116 that summarizes the Company's position.

III. PROPOSAL TO TERMINATE INTERRUPTIBLE RIDER IRP-D

Q. Have you reviewed the Company's proposal to terminate Interruptible Rider IRP-D at the end of the current ESP?

A. Yes. As discussed by Company witnesses Gary Spitznogle (at page 12) and Andrea Moore (at page 9), AEP Ohio is proposing to eliminate its current interruptible rider with the initiation of ESP III beginning June 2015. There are currently 3 large customers participating in the Company's IRP-D interruptible load program. These customers provide a significant amount of emergency reliability (mW) to the AEP

Ohio zone (and the Company's firm customers) that could be potentially lost if the Company's proposal is adopted.[1]

Q. Would you describe Rider IRP-D?

A. The current version of Rider IRP-D was approved by the Commission in Case No. 11-346-EL-SSO (the ESP II Order). In its Order in that case, the Commission specifically recognized the benefits of an AEP Ohio interruptible load program and established an interruptible credit of $8.21/kW month. At page 26 of its Order, the Commission stated as follows:

> **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 factors and benefits of the IRP-D interruptible load program change as a result of ESP III?

A. No, not in my opinion. While I will recommend modifications to the Company's interruptible load program and credit as an alternative for current version of Rider

[1] The Company provided the mW of interruptible contract capacity under Rider IRP-D in its confidential response to IEU Set 3, Int-036.

IRP-D during the Company's ESP III, all of the benefits that were previously cited by the Commission for the existing IRP-D rate also support the continuation of an interruptible load program for the Company during the term of ESP III.

Q. What is the Company's rationale for terminating rider IRP-D?

A. AEP Ohio cites two rationales: first, Mr. Spitznogle states that the market can provide comparable offerings and second, Ms. Moore states that because the Company will become a wires-only company, it may not be "the entity best able to provide an interruptible service product..."[2]

Q. Is it correct that AEP-Ohio will be a wires-only company during ESP III?

A. No. The Company is proposing to maintain its Ohio Valley Electric Corporation ("OVEC") generation as a "hedge against market volatility."[3] The OVEC generation is proposed to be charged to all AEP-Ohio customers on a non-bypassable basis through the Power Purchase Agreement ("PPA") Rider. While the energy and capacity associated with the OVEC generation will be bid into PJM, the economic effect of the proposed PPA rider on customers is consistent with a company that continues to own or otherwise retain some generation resources. As discussed by OEG witness Taylor, OEG generally supports the proposed OVEC PPA rider with some modifications.

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[2] Direct Testimony of Andrea Moore at page 9.
[3] Application of AEP-Ohio at page 8.

Q. Do you agree that it is appropriate to terminate the Company's interruptible load program (Rider IRP-D)?

A. No. First, this proposal would be inconsistent with the policy established for the FirstEnergy Companies and Duke Energy Ohio. The Commission approved an interruptible credit for FE's large industrial customers as part of FE's current ESP. FE has long been a wires-only company, having divested its generation in the mid-2000's. Yet, the Commission approved FE's interruptible credit of $10/kW month and the program (and rate) continue despite the fact that FE is a wires-only company.

In the case of Duke, the Commission approved current ESP (Case No. 11-3549-EL-SSO) includes an interruptible load program with an interruptible credit equal to 50% of the PJM applicable "Net Cone" rate per mW. Net Cone is the net cost of new entry (new capacity) and is computed by calculating the annual revenue requirement of a new combustion turbine less the net revenue credits that could be obtained through sales of ancillary services and energy ("E&AS"). The PJM Reliability Pricing Model ("RPM") utilizes Net Cone as a key input into the VRR Curve (Variable Resource Curve).[4] In a capacity market that is in equilibrium, Net Cone reflects a measure of the theoretical market capacity price.

While the FE interruptible load program (with its $10/kW month credit), is only available to SSO customers, the Duke interruptible load program is available to both

[4] The VRR Curve functions as the capacity demand curve in the Base Residual Auction.

SSO and shopping customers. Duke is in the process of divesting its generation and will become a wires-only company like FE and, AEP Ohio in the future. Thus, there is at least an established Commission policy approving interruptible load programs and rates for wires-only companies.

Q. What is the current value of Net Cone on a $/kW month basis for the AEP zone?

A. Baron Exhibit__(SJB-3) contains an excerpt from a PJM Reliability Pricing Model Base Residual Auction ("BRA") 2017-2018 Planning Period Parameters summary. As show in this excerpt, the Net Cone for Cone Area 3 (AEP Ohio zone) is $352.63/Mw-Day (ICAP basis). This equates to $10.73/kW month. Using the Duke 50% of Net Cone construct produces an interruptible credit of $5.36/kW month. This is about 35% less than the current AEP Ohio interruptible credit of $8.21/kW month.

Q. In its Order in the ESP II case approving the current IRP-D interruptible rate credit, the Commission cited the benefit of interruptible load to AEP-Ohio and its customers that can be interrupted on short notice. Has this reliability benefit of interruptible load been recently confirmed in Ohio and in PJM as a whole?

A. Yes. Pursuant to the terms and conditions of the IRP-D rider, interruptible load must be available for interruption at any time by the Company, at its sole discretion, subject to annual limitations on the number of hours of such interruption in the case of discretionary interruptions. In the case of emergency interruptions, there are no such limitations. The Company will attempt to provide 100 minutes of notice for discretionary interruptions. <u>However, in emergencies, (including PJM emergencies), AEP-Ohio can request interruptions without notice.</u>[5] In addition, pursuant to AEP's ability (and the Commission requirement) to bid its IRP-D interruptible load into the PJM demand response program, reliability benefits are also provided on a PJM RTO-wide basis.

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__(SJB-4) contains excerpts from these SNL Financial articles.

Q. Do these recent reliability events lend support for rejecting the termination of AEP Ohio's interruptible load program?

A. Yes. I believe that these recent events provide support for continuing the AEP-Ohio based interruptible load program, even after generation divestiture. The availability

[5] A customer must provide evidence that it can interrupt within a 10 minutes period to take service under the rider.

of AEP-Ohio interruptible load/capacity resources will provide additional reliability to the Company's Ohio customers.

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 4 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__(SJB-5) contains summary information on these coal unit retirements from a recent SNL Financial article (March 25, 2014).

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

A. Yes. Such an approval would set an inconsistent policy for AEP Ohio compared to the other two large investor owned utilities in the State. A steel mill in Northern Ohio or Southwest Ohio would potentially have a significant economic advantage over a similar customer in AEP Ohio's service area.

Q. As you noted previously, one of the rationales relied on by the Company to terminate its interruptible load program is that there are market alternatives. Is this a realistic alternative for current interruptible customers?

A. Not really. OEG asked the Company how terminated IRP-D customers could participate in the market, if the Commission were to approve its request in this case. I have attached the Company's response to OEG 7-001 as Baron Exhibit__(SJB-6). Based on this response, there will be little opportunity to for terminated IRP-D customers to fully participate in PJM's demand response program. Under the Company's proposal in this case, Rider IRP-D will be terminated on May 31, 2015. Because the PJM Base Residual Auctions have already occurred for PJM planning years 2015/2016 and 2016/2017 customers cannot now bid their interruptible load into these PJM auctions. The BRA for PJM planning year 2017/2018 will take place in May 2014, well before a decision by the Commission is issued in this ESP III case. An existing IRP-D customer would have to make the choice to terminate its participation in Rider IRP-D if such customer wanted to participate in the BRA without knowing whether the Commission accepted the Company's proposal. Once a customer submits a Demand Response bid into the BRA (assuming it is accepted), then such customer has an obligation to provide the Demand Response capacity to PJM and cannot participate in any AEP Ohio interruptible load program. This is not a reasonable choice that should be forced on existing IRP-D customers even before the hearings are conducted in this case.

Q. Does the Company present other possible options for market participation by terminated IRP-D customers in its response to OEG 7-001?

A. Yes. However, these are not realistic options. One option cited by the Company is to "hope" that a Curtailment Service Provider ("CSP") previously bid demand response load into the BRA without actually having signed-up such load and therefore would have space available. This is clearly not a reasonable option for an IRP-D customer to pursue as a replacement for AEP Ohio's interruptible load program.

Q. The Company's response to OEG 7-001 also suggests that customers can participate at any time in PJM Incremental Auctions. Is this a feasible option for terminated IRP-D customers?

A. No. While a customer could participate in Incremental Auctions ("IA"), based on the history of PJM incremental capacity auctions the payments for capacity, including demand response load, are significantly lower than the standard RPM capacity prices produced by the annual BRAs. Baron Exhibit__(SJB-7) 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 significantly lower than the corresponding year's BRA RPM price. For example, in delivery year 2014/2015, the BRA auction result was in $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. Clearly, the Incremental Auctions do not provide a realistic substitute for the IRP-D interruptible load program.

Q. Does OEG have a recommendation to the Commission that would preserve AEP-Ohio's interruptible load program?

A. Yes. OEG recommends that the Company continue to offer its own interruptible load program. OEG recommends that AEP Ohio offer two optional interruptible rates. The first option would be based on the approach approved by the Commission for Duke and would be patterned after the PJM Limited Emergency Demand Response program. As I discussed above, Duke's interruptible rate has two important features: 1) the interruptible credit is set equal to 50% of Net Cone (about \$5.36/kW-month) and 2) the rate is available to all customers, both SSO and shopping. While the \$5.36/kW-month credit is significantly less than the current \$8.21/kW-month credit, it is greater than the current PJM RPM rate. As such, it represents a balanced proposal that provides the Company and its customers an additional source of reliability during emergency situations and also provides the Company's largest customers with an option (in the form of lower quality service) for a lower electric rate than would be available with firm power options only. With regard to this last point, the continuation of an AEP-Ohio interruptible load program for both SSO and shopping customers provides customers and Ohio a potential economic development benefits because it allows customers that are willing to forgo firm service an opportunity to lower their overall power costs and remain competitive.

Q. Please describe OEG's second optional interruptible rate proposal.

A. OEG's second optional interruptible rate would be an unlimited emergency interruptible rate that incorporates the existing $8.21/kW per month credit. Customers electing this option could be interrupted at any time in the event of an AEP Ohio or PJM emergency with the same notice provisions that currently exist for rider IRP-D associated with emergency interruptions (10 minute notice for emergency interruptions). There would be no limitation on the annual number of emergency interruptions or the length of such interruptions. Emergency interruptions would include interruptions called by PJM or localized AEP Ohio zonal emergencies.

Q. How do the terms of these two alternatives interruptible rate options compare?

A. OEG's first option, which provides for an interruptible credit equal to 50% of Net Cone (currently about $5.36/kW-month) would be patterned after the current PJM Limited Emergency program, which limits interruptions to 10 times during the months of June through September. These are the only interruptions that a participating customer is required to satisfy (these are interruptions for which there is a penalty imposed for a failure to interrupt). All other emergency interruptions are voluntary. Under the OEG's second alternative interruptible rate proposal, a participating customer would receive the current $8.21/kW-month credit. There would be no limitations on the frequency, duration and timing (i.e., any month of the year) of emergency interruptions. All else being equal, this increases the reliability value of the interruptible load compared to the PJM Limited Emergency program restrictions, thus justifying a larger monthly credit.

Q. Do you have a recommendation regarding the maximum mW of interruptible load that could participate in the AEP Ohio program?

A. Yes. OEG suggests that the program (combined load electing both OEG optional rates) be limited to the current IRP-D mW limitation of 525 mW. At a minimum, however, all current IRP-D customers should be permitted to participate in one or the other of the OEG optional rates, in the event that the Commission elects to impose a more restrictive cap on participation than the current 525 mW level.

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

A. The Commission should require AEP Ohio to recover the costs associated with any interruptible credits through Rider EE/PDR. One purpose of the interruptible load program is to promote energy efficiency and reduce the Company's peak demand as required by R.C. Section 4928.66. This purpose aligns with the purpose of Rider EE/PDR. Thus, it is appropriate to require AEP Ohio to recover the incremental costs associated with the interruptible credit through Rider EE/PDR.

Finally, AEP Ohio 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 through Rider EE/PDR. This crediting approach was required when the Commission approved the current interruptible program in AEP Ohio's ESP II.

IV. PROPOSED RECOVERY OF DEFERRED CAPACITY CHARGES

Q. Would you briefly explain your understanding of the Company's proposal to recover its deferred capacity charges from customers?

A. In Case No. 10-2929-EL-UNC ("Capacity Case"), the Commission approved a \$188/mW-day capacity rate for AEP Ohio applicable to CRES providers within the AEP Ohio FRR zone. At the same time, the Commission required the Company to actually charge CRES providers the PJM Reliability Pricing Mechanism ("RPM") rate per mW-day, and defer the difference (the average RPM rate during the three year ESP II term ending May 2015 was lower than the authorized \$188/mW-day state compensation mechanism rate). The Commission further ordered the Company to amortize \$1/mWh of its Rate Stability Rider ("RSR") charges against the deferred capacity balance. The RSR is collected through a non-bypassable rate from all customers during the term of ESP II. Any remaining unrecovered balance in the capacity deferral account was to be recovered at the conclusion of ESP II (May 2015) through an amortization over 3 years.

Q. Has the Company presented an estimate of the unrecovered balance in the capacity deferral account?

A. Yes. Company witness Allen estimates that the balance of unrecovered charges will be $463 million by May 31, 2015.

Q. Is the Company proposing a capacity charge deferral recovery mechanism in this case?

A. Not specifically, though Mr. Allen presents testimony describing the Company's proposal to continue the RSR during the term of ESP III for the purpose of recovering the deferred capacity charges. The Company estimates that it will be able to recover the deferred balance within the first 34 months of ESP III. The Company states that it will file a separate application to implement the RSR based deferred capacity cost recovery mechanism.

Q. Do you oppose the Company's proposal to recover its deferred capacity costs through the RSR?

A. In part. While I do not object to using the existing RSR to recover the deferred capacity charges during ESP III, I believe that it is appropriate to exclude customers (or customer load) that are currently taking service from the Company pursuant to a Unique Arrangements (sometimes referred to as "Reasonable Arrangements" or "RA") order of the Commission. These customers, pursuant to the RA contracts approved by the Commission, did not shop during the term of ESP II and therefore were not responsible for the deferred capacity costs associated with unrecovered charges to CRES providers who served the Company's shopping customers.[6] Therefore, my proposal is consistent with the fundamental regulatory policy that costs should be charged to the cost causer.

Q. Would you provide the basis for your recommendation that RA customers be exempted from deferred capacity cost recovery charges via the RSR, beginning June 2015?

A. Yes. First, as noted by the Commission in its ESP II order, "as a result of the Capacity Case, customers may be able to lower their bill impacts by taking advantage of CRES provider offers allowing customers to realize savings that may not have otherwise occurred without the development of a competitive retail market."[7] Because customers subject to an RA contract could only shop during the period in which the capacity deferral charges were accrued if they terminated the RA contract (thus forfeiting the RA discounts authorized by the Commission), these RA customers could not take advantage of the lower RPM capacity rates actually charged to the CRES providers. It is the under-recovery of these CRES provider costs that is now the subject of the capacity deferral recovery. In the event that an RA customer elected to terminate its contract and shop, then such customer would be subject to the RSR capacity deferral charge consistent with its application to all other SSO and shopping customers.

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[6] While RA customers were permitted to shop at their election, they would no longer receive any RA benefits pursuant to the Commission approved contract.

[7] Order in Case No. 11-346-EL-SSO, et al. at 36.

Q. Didn't the RA customers receive other benefits (discounts) through their respective RA contracts?

A. Yes. However, the Commission order in each RA contract approved a specified set of discounts that should be provided to these reasonable arrangement customers based on a variety of state policy objectives. For example, in the case of OEG member Timken, the Commission relied on testimony that the RA contract "will sustain Timken's competitiveness and level of employment at the Canton Facility."[8]

Effectively, by now charging such RA customers the deferred capacity charges associated with shopping customer load served by CRES providers, some of the previously Commission authorized economic benefit is being taken back. At the same time, the RA customer did not have the benefit of potentially attractive CRES provider rates. In my opinion, this is contrary to the original basis for approving the RA contracts. In the case of Timken, the annual RSR charges associated with the recovery of deferred capacity charges would be in excess of $2.5 million. Because this represents a future recovery of AEP Ohio costs incurred while RA customers were subject to the special Commission approved rates, charging a deferred capacity cost RSR to a reasonable arrangements customer such as Timken means that the approved rate for such RA customer will now exceed the level assumed by the Commission in its order. As discussed by the Commission in its orders approving

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[8] PUCO Order in Case 10-3066-EL-AEC at 7.

RA contracts, the approved discounts permitted the customer to continue operating and providing jobs and other benefits to the State of Ohio.[9]

Q. Did the Commission make similar findings with regard to the benefits provided by the Company's other two RA customers (Eramet Marietta, Inc. and Globe Metallurgical)?

A. Yes. In its Order in Case No. 09-516-EL-AEC involving Eramet's RA contract approval, the Commission cited the record evidence in the case that the Eramet RA Stipulation "advances the public interest, in that it addresses the concerns of OCC, OEG and CSP, and provides significant benefits to ratepayers, including ensuring job retention and, potentially encouraging new employment through potential for growth. The Stipulation also contributes to the regional economic through significant local and state tax dollars and employment and other business opportunities resulting from the viable operation of the facility."[10]

In Case No. 13-1170-EL-AEC involving the approval of an RA Stipulation for Globe Metallurgical, the Commission cited evidence that approval of an RA amendment would allow Globe to "expand its pledged workforce by ten percent within six months from the implementation of its fixed megawatt-hour price mechanism." The Commission believed that this "not only benefits the public

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[9] Specifically, the Joint Application in Case No. 10-3066-EL-AEC cites the need for a special rate to "sustain Timken's competiveness and employment rates."

[10] Commission Order in Case No. 09-516-EL-AEC at page 12.

interest by facilitating job growth in southeast Ohio, but also aids in enhancing Ohio's effectiveness in the global economy."[11]

Q. In the event that an RA customer terminates its RA contract or otherwise reaches contractual limits such that the RA discount provisions are no longer in effect prior to May 31, 2015, should the RA customer pay for a portion of the deferred capacity charges?

A. Yes. If the customer is no longer subject to the RA discounts because the contract has terminated or the discounts are no longer available because of contractual funding limitations during the term of ESP II (the current ESP) while capacity charges are being deferred, then it is appropriate for the RA customer to pay a pro-rata portion of the otherwise applicable RSR charge during ESP III. OEG's specific proposal is to pro-rate the otherwise applicable RSR charge using a percentage factor reflecting the number of months during the capacity charge deferral period in which the customer was no longer covered by the RA contract and discounts. The percentage factor would simply be the number of months during the capacity charge deferral period in which the customer was no longer receiving RA discounts divided by the total number of months in which AEP Ohio was deferring capacity charges. This percentage factor would then be applied to the otherwise applicable RSR charge in ESP III to determine the customer's actual RSR charge.

[11] Commission Order in Case No. 13-1170-EL-AEC at pages 4 – 5.

Q. If your recommendation to exclude in whole or in part RA customers from paying the deferred capacity charges is accepted by the Commission, will the Company be able to recover all of its deferred capacity costs during the 36 months of ESP III?

A. The Company has estimated that it expects that the entire balance of deferred capacity costs will be recovered with 34 months of ESP III under the assumption that RA customers are included in the proposed RSR charge. Based on the Company's response to OEG 5-1, there are currently three customers taking service under reasonable arrangements with the Company. Since the load and energy usage of RA customers is highly confidential, I am not able to calculate the specific impact to determine if all deferred costs will be recovered in 36 months. However, there is no reason that any remaining unrecovered deferred costs cannot be recovered in the Company's next ESP and I would recommend such recovery treatment, if necessary.

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 2nd day of May 2014.

Jessica K. In

Notary Public

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

BEFORE THE

PUBLIC UTILITY COMMISSION OF OIHO

In The Matter Of The Application Of Ohio Power Company For Authority To Establish A Standard Service Offer Pursuant To 4928.143, Ohio Rev. Code, In The Form Of An Electric Security Plan.	: : : : :	**Case No. 13-2385-EL-SSO**
In The Matter Of The Application Of Ohio Power Company For Approval Of Certain Accounting Authority.	: : :	**Case No. 13-2386-EL-AAM**

EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF

THE OHIO ENERGY GROUP

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

May 2014

BEFORE THE

PUBLIC UTILITY COMMISSION OF OIHO

In The Matter Of The Application Of Ohio Power Company For Authority To Establish A Standard Service Offer Pursuant To 4928.143, Ohio Rev. Code, In The Form Of An Electric Security Plan.	: : : : :	**Case No. 13-2385-EL-SSO**
	:	
In The Matter Of The Application Of Ohio Power Company For Approval Of Certain Accounting Authority.	: : :	**Case No. 13-2386-EL-AAM**

EXHIBIT__(SJB-1)

OF

STEPHEN J. BARON

ON BEHALF OF

THE OHIO ENERGY GROUP

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

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 March 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 March 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 March 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 March 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
of
Stephen J. Baron
As of March 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 fore-casting.
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 March 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 March 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 March 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.

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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

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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.

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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.

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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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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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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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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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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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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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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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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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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

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

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

BEFORE THE

PUBLIC UTILITY COMMISSION OF OIHO

In The Matter Of The Application Of Ohio Power Company For Authority To Establish A Standard Service Offer Pursuant To 4928.143, Ohio Rev. Code, In The Form Of An Electric Security Plan.	: : : : : :	**Case No. 13-2385-EL-SSO**
In The Matter Of The Application Of Ohio Power Company For Approval Of Certain Accounting Authority.	: : :	**Case No. 13-2386-EL-AAM**

EXHIBIT__(SJB-2)

OF

STEPHEN J. BARON

ON BEHALF OF

THE OHIO ENERGY GROUP

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

OHIO POWER COMPANY'S RESPONSE
THE OFFICE OF THE OHIO CONSUMERS' COUNSEL'S
DISCOVERY REQUEST
PUCO CASE NO. 13-2385-EL-SSO et al.
SEVENTH SET

INTERROGATORY

INT-7-116 Reference Moore Direct, p. 5, ll. 3-5. Please confirm that you propose to allocate to customer or rate classes the costs recovered through the Storm Damage Recovery Rider (SDRR) on the basis of each class's contribution to total base distribution revenues. Please explain the basis for your proposal to allocate SDRR costs in this fashion.

RESPONSE

The Company proposes to collect or refund the amounts through the Storm Damage Recovery Rider on a uniform annual percentage of base distribution revenues. Base distribution rates are designed to collect the allocated costs of the distribution system. By using a percentage of Base D, the Company is collecting from each customer based on their cost to serve the distribution system as a whole. In addition, this allocation is consistent with previous distribution riders approved by the Commission.

Prepared By: Andrea E. Moore

BEFORE THE

PUBLIC UTILITY COMMISSION OF OIHO

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EXHIBIT__(SJB-3)

OF

STEPHEN J. BARON

ON BEHALF OF

THE OHIO ENERGY GROUP

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

RPM CONE and E&AS Values for 2017/2018 Base Residual Auction

ICAP to UCAP Conversion Factor:	
UCAP Price = ICAP Price/(1 - Pool-Wide Average EFORd)	
Pool-Wide Average EFORd for 2017/2018 =	**5.65%**

CONE Area 1: AE, DPL, JCPL, PECO, PS, RECO
CONE Area 2: BGE, PEPCO
CONE Area 3: AEP, APS, ATSI, ComEd, Dayton, DEOK, Duquesne (DLCo), EKPC
CONE Area 4: MetEd, Penelec, PPL
CONE Area 5: Dominion
MAAC CONE used is the lowest of the three CONE Areas 1, 2, and 4.

	CONE Area 1	CONE Area 2	CONE Area 3	CONE Area 4	CONE Area 5	MAAC: Used Area 2 CONE	RTO
Benchmark CONE (2016/2017 BRA Value): Levelized Revenue Requirement, $/MW-Year	$152,460	$142,223	$139,485	$146,471	$124,920	$142,223	$139,392
12 Months Handy Whitman Index (July 1, 2013)	2.9%	2.9%	3.0%	2.9%	2.9%	2.9%	2.9%
Region basis for the Handy Whitman Index	North Atlantic	North Atlantic	North Central	North Atlantic	South Atlantic	North Atlantic	North Atlantic
2017/2018 BRA CONE, escalated by Handy Whitman Index, $/MW-Year	$156,881	$146,348	$143,670	$150,718	$128,542	$146,348	$143,434
Gross CONE, $/MW-Day, UCAP Price	**$455.55**	**$424.96**	**$417.19**	**$437.65**	**$373.26**	**$424.96**	**$416.50**
Historic (2011-2013) Net Energy Revenue Offset, $/MW-Year	$28,686	$36,360	$12,761	$26,452	$26,492	$36,360	$20,224
Zonal LMP used for Net Energy Offset Calculation	AE Zonal LMP	BGE Zonal LMP	ComEd Zonal LMP	MetEd Zonal LMP	Dominion Zonal LMP	BGE Zonal LMP	PJM Average LMP
Ancillary Services Offset, $/MW-Year per Tariff	$2,199	$2,199	$2,199	$2,199	$2,199	$2,199	$2,199
Net CONE, $/MW-Day, ICAP Price	$345.20	$295.31	**$352.63**	$334.43	$273.56	$295.31	$331.54
Net CONE, $/MW-Day, UCAP Price	$365.87	$313.00	$373.75	$354.46	$289.95	$313.00	$351.39
VRR Curve Point (a) UCAP Price, $/MW-Day *	$548.81	$469.50	$560.63	$531.69	$434.93	$469.50	$527.09

* VRR Curve Point (a) UCAP Price is the higher of 1.5 Net CONE or Gross CONE.

BEFORE THE

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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

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.

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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.

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Article

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.

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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

Article

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

SNL

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

SNL

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.

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PUBLIC UTILITY COMMISSION OF OIHO

In The Matter Of The Application Of Ohio Power Company For Authority To Establish A Standard Service Offer Pursuant To 4928.143, Ohio Rev. Code, In The Form Of An Electric Security Plan.	:	**Case No. 13-2385-EL-SSO**
In The Matter Of The Application Of Ohio Power Company For Approval Of Certain Accounting Authority.	:	**Case No. 13-2386-EL-AAM**

EXHIBIT__(SJB-6)

OF

STEPHEN J. BARON

ON BEHALF OF

THE OHIO ENERGY GROUP

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

OHIO POWER COMPANY'S RESPONSE
TO OHIO ENERGY GROUP'S
DISCOVERY REQUEST
PUCO CASE NO. 13-2385-EL-SSO et al.
SEVENTH SET

INTERROGATORY

INT-7-001 In the event that the Public Utilities Commission of Ohio approves the Company's request to terminate Rider IRP-D in this case, please provide an explanation of how existing IRP-D customers could participate in the PJM Limited Emergency Demand Response program. Specifically:

a. Please confirm that the first PJM Base Residual Auction that an existing IRP-D customer would be able to bid demand response into would be the auction for Delivery Year 2018/2019 that would provide demand response payments beginning in June 2018.

b. Please explain what other options such customer would have with regard to obtaining PJM Limited Emergency Demand Response payments prior to June 2018.

c. Would such customer be able to participate in incremental auctions and receive PJM Limited Emergency Demand Response payments prior to June 2018?

RESPONSE

a. As of March 21, 2014, PJM has held base residual auctions for delivery years through 2016/2017. An existing IRP-D customer could elect to participate in the upcoming base residual auction for 2017/2018, based upon the Company's proposal to terminate Rider IRP-D effective May 31, 2015. However, if a customer elected to participate in the 2017/2018 base residual auction, they would not be eligible for Rider IRP-D in 2017/2018 if that program were continued.

b. A customer could participate in any incremental auctions occurring for delivery years beginning after May 31, 2015. Further, as of March 21, 2014, the customer could sign up with a Curtailment Service Provider (CSP) that has already made commitments in the PJM auctions for delivery years through May 31, 2017. It is possible that CSPs have not yet signed up enough customers to meet their RPM commitments for given years. The availability of the PJM Limited Emergency Demand Response program is subject to the limitations prescribed by the PJM tariff. A customer would be free to sign up under any of the PJM Demand Response programs, and not restricted to only the Summer Limited Emergency product.

c. Yes, if there is an incremental auction held for delivery years beginning after May 31, 2015, the customer may participate.

Prepared By: Andrea E. Moore

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EXHIBIT__(SJB-7)

OF

STEPHEN J. BARON

ON BEHALF OF

THE OHIO ENERGY GROUP

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

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	**	**

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 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	**	**
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	**	**
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	**
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

* The Annual, Extended Summer and Limited capacity product types were implemented starting with the 2014/2015 Delivery Year

** LDA was not modeled

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DIRECT TESTIMONY

OF

ALAN S. TAYLOR

ON BEHALF OF

THE OHIO ENERGY GROUP

SEDWAY CONSULTING, INC.
BOULDER, COLORADO

May 6, 2014

BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

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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 28 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, and fuel adjustment clauses.

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 Ohio Power Company ("AEP Ohio" or "the Company").

Q. What is the purpose of your testimony?

A. I am supporting the concept of a Power Purchase Agreement (PPA) Rider associated with the net benefits of AEP Ohio's portion of the Ohio Valley Electric Corporation (OVEC) power plants that is discussed in Company Witness William Allen'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 PPA Rider that I am proposing that could enhance its stabilizing nature and provide benefits over a longer 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 PPA Rider that is being proposed by AEP 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 fluctuations in natural gas prices, weather, 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 AEP Ohio's PPA Rider. I recommend that it be extended over a longer period of time than just the three-year ESP III. During the ESP III, AEP Ohio's forecasts indicate that the costs of the OVEC generation will exceed its energy and capacity market benefits. As discussed above, this is likely to reverse (and indeed is shown to do so in AEP Ohio's forecasts) in ESP IV and ESP V, with the OVEC benefits exceeding costs in those periods. I think that AEP Ohio's customers should be assured of the longer-term net benefits of the rider by locking it in for a period that spans ESP III through ESP V. Also, I propose a levelization approach that would flatten the PPA Rider and remove what is otherwise likely to be a front-loaded cost to AEP Ohio's customers under the current plan. The proposed levelization approach would advance the long-term benefits, bring the rider closer to a market-neutral hedge in all years, and indeed would result in a negative rider (i.e., a credit to customers' bills) in the first year – and likely for all subsequent years. Because the levelization approach would involve AEP 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 AEP 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 provides early year savings for consumers and is revenue neutral to AEP. To distinguish this modified rider from AEP Ohio's proposed PPA Rider, I have labeled it the PPA Stability Rider. Finally, it important to recognize that because the PPA Stability 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 PPA 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 AEP 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 AEP Ohio's customer supply portfolio can provide the peace of mind and avoid the concerns associated with customers being 100% reliant on marginal-cost electricity markets.

Q. Do you think that 100% reliance on marginal-cost 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 time-frame 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. 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 receive 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 PPA rider could be used to stabilize the rates of AEP Ohio's customers and protect them from being overly exposed to the energy market?

A. Exactly.

III. DESCRIPTION OF OVEC SUPPLY RESOURCE AND AEP OHIO'S PROPOSED PPA RIDER

Q. Please describe the OVEC supply resource.

A. The Ohio Valley Electric Corporation (OVEC), of which AEP 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. AEP Ohio has entitlement to a 19.93% share of OVEC. AEP Ohio asked its co-participants in OVEC to consent to a sale or transfer of AEP Ohio's portion of OVEC to a new owner/participant. That consent was withheld. Thus, AEP Ohio's witness William Allen introduced testimony with a proposal to implement a PPA Rider that would pass through to its customers the net benefits (be they positive or negative) of the OVEC resource during ESP III.

Q. Do you think that the PPA Rider proposed by Mr. Allen would be good for AEP Ohio's customers?

A. In concept, yes, but I think that the ESP III is too short of a period for the OVEC resources to provide the rate stabilizing benefits that they could if the rider was extended to a longer time period.

Q. Before turning to the longer time period issue, why do you think that the OVEC PPA Rider would be good – in concept – for AEP 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 AEP Ohio's customers?

A. In the context of the PPA Rider's financial settlement, yes; but it is important to recognize that the PPA 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 PPA 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 AEP 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 AEP Ohio's forecast from its Fall 2013 analysis showed that OVEC's combined demand and energy costs are expected to be above market prices in the near-term. Specifically, the OVEC net benefits are expected to be negative (i.e., where market prices are less than OVEC costs) in 2015 and 2016 but positive in 2017 and in all years thereafter. These net benefits are depicted in Taylor

Exhibit__(AST-2) which is a summary of information extracted from AEP Ohio's response to IEU RPD 2-001 Competitively-Sensitive Confidential Attachment 2 - Ohio Bill Mid Band worksheet. By "net benefits," I am referring to the amount that the energy and capacity revenues associated with AEP Ohio's portion of the OVEC assets exceed AEP Ohio's portion of the OVEC costs. The energy and capacity revenues represent what AEP 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 AEP 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 AEP Ohio's Fall 2013 forecast and analysis, it appears that much of the OVEC benefits (when net benefits are expected to be positive) will occur after ESP III?

A. Yes; and while it may be AEP Ohio's intention to offer the PPA Rider in subsequent ESPs, I think it would be appropriate to lock in the PPA Rider so that customers can be assured of the opportunity to benefit from the expected OVEC positive net benefits in future years.

IV. PROPOSED PPA STABILITY RIDER

Q. So your proposed PPA Stability Rider would extend beyond ESP III?

A. Yes. I am proposing a rider that would start in June, 2015 at the beginning of ESP III and continue through and beyond ESP IV and ESP V 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 would be positive. In fact, based on the results depicted in Taylor Exhibit__(AST-2), AEP Ohio's Fall 2013 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 $49 million or about $5 million/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 PPA Stability Rider beyond 2024 yield potentially greater benefits?

A. Possibly, but going too far into the future may expose AEP Ohio's customers to unknown risks (such as higher-than-expected CO_2 costs, should federal or state legislation be enacted in this area). As I will discuss later, the concept behind the

PPA Stability Rider is that both AEP 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 PPA Stability Rider would be levelized. Please describe this process.

A. The PPA Stability Rider would be premised on AEP Ohio's approximately $49 million 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 $5.116 million/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 PPA Stability Rider. However, because the forecasted OVEC net benefits are expected to be negative in the first couple of years, then increasing into positive values later, a flat stream of payments to AEP Ohio's customers will entail the utility pre-paying future savings. AEP 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 AEP 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 AEP Ohio), the same AEP 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 AEP 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 $1.312 million/year. The difference of the levelized return and the levelized net benefits would yield the initial PPA Stability Rider of -$3.804 million/year (= $1.312 million - $5.116 million), with the negative value reflecting a rider credit. This first year rider credit would be adjusted for the 2015 partial year and for an AEP 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, there would be a true-up process. Actual OVEC net benefits for the year that just ended (and perhaps any known capacity revenues or budgets for the prospective year) would be compared to that year'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 Line 11 on Page 2 of 3 of that exhibit depicts a specific scenario of "actual" OVEC net benefits. 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 PPA Stability 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 PPA Stability Rider.

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

A. Almost. There is one final step depicted in Taylor Exhibit__(AST-3). In order to provide incentives for AEP 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 AEP Ohio's customer bills. This is expected to be a credit of $2 million - $4 million/year.

Q. Would all AEP Ohio customers get the PPA Stability 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. Given that the proposed PPA Stability Rider is likely to be a negative number (i.e., a credit) in every year, I would think that it would be hard to pass up. That said, 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 AEP 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 PPA Stability 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 PPA Stability Rider is based on AEP Ohio's Fall 2013 forecast of 2015-2023 OVEC net benefits, the forecast itself is largely irrelevant to the PPA Stability 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 PPA Stability Rider at the right level; but the forecast need not be anything more than a ball-park 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 year to year in providing the counter-cyclical benefits of dampening price swings in market prices as described earlier.

Q. What if the OVEC net benefits never turn positive over the term of your proposed PPA Stability Rider?

A. As I mentioned earlier in my testimony with the example of homeowner's insurance, just because a hedge does not result in positive net cash flows does not mean that it was a waste of money. A hedge can protect against risks; and if those risks do not materialize, so much the better. I doubt that most people who have lost their houses to a fire or flood have rejoiced in the positive net cash flows from receiving more money from the insurance company than they paid in insurance policy premiums. Most homeowners – at least those who are sensible and like their homes – hope that their homeowner's insurance policies never translate into positive net cash flow hedges. Similarly, if the OVEC net benefits never turn positive, that means that AEP Ohio's customers will be enjoying low-cost market prices that will continue to be a substantial portion of their rate structure. The PPA Stability Rider will automatically adjust over time from being an initial credit to a positive adder on customers' bills. Given the circumstances that AEP Ohio is facing (e.g., considerable coal plant retirements occurring or soon to occur throughout PJM and the Midwest), I think that this is a low probability scenario – and one in which, just like the homeowner's insurance example, the PPA Stability Rider would still provide the peace of mind benefits even without direct financial benefits.

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

____
Alan S. Taylor

Sworn to and subscribed before me on this
_6_ day of May, 2014.

Connie Nichols
____
Notary Public

Connie Nichols
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20014040409
MY COMMISSION EXPIRES December 31, 2017

BEFORE THE

PUBLIC UTILITY COMMISSION OF OIHO

In The Matter Of The Application Of Ohio Power Company For Authority To Establish A Standard Service Offer Pursuant To 4928.143, Ohio Rev. Code, In The Form Of An Electric Security Plan.	:	**Case No. 13-2385-EL-SSO**
In The Matter Of The Application Of Ohio Power Company For Approval Of Certain Accounting Authority.	:	**Case No. 13-2386-EL-AAM**

<u>PUBLIC</u>

EXHIBITS

OF

ALAN S. TAYLOR

ON BEHALF OF

THE OHIO ENERGY GROUP

SEDWAY CONSULTING, INC.
BOULDER, COLORADO

May 6, 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

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 **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.

2001 **Negotiation of Full-Requirements Purchase Contract**
Client: Georgia cooperative utility

Assisted in negotiation of a $2 billion power purchase contract. Mr. Taylor worked with a team of legal experts and other consultants to assist the client in negotiating a 15-year full-requirements contract with a large, national power supplier. Detailed modeling simulations were performed to compare the complex transaction to the utility's own self-build alternatives. Mr. Taylor helped investigate and negotiate detailed provisions in the power supply contract concerning ancillary services and other operational parameters.

2001 **Evaluation of Resource Proposals**
Client: North Carolina municipal utility

Reviewed responses to a utility resource solicitation and assisted the client in developing a short list of the best bidders. Mr. Taylor reviewed the results of the client's economic analysis of the proposals and provided insights on various nonprice factors related to each of the top-ranked proposals. Mr. Taylor helped the client in structuring and strategizing for the negotiation process.

2000- **Solicitation for New Resources**
2001 Client: Public Service of Colorado

Assisted in the evaluation of a large number of multi-option proposals for new power supplies in the 2002-2005 time frame. Mr. Taylor managed a team of a dozen individuals who performed economic and nonprice evaluations of conventional and renewable proposals. Mr. Taylor developed recommendations for a short list of the best resources and managed a supplemental evaluation of second-tier bidders when the client's capacity needs subsequently increased. Ultimately, over $2 billion of contracts were negotiated for over 1,700 MW of new power supplies under terms of up to 10 years. Mr. Taylor testified before the Colorado Public Utilities Commission on the processes and results of both the primary and supplemental evaluations.

1999- **Solicitation for New Resources**
2000 Client: MidAmerican Energy

Reviewed MidAmerican's solicitation for new power supplies for the 2000-2005 resource planning period. Mr. Taylor managed a team of individuals who performed an independent parallel evaluation of MidAmerican's analysis of responses to the utility's request for proposals (RFP). Mr. Taylor reviewed MidAmerican's evaluation and negotiation process and testified to the fairness and appropriateness of MidAmerican's actions. He filed testimony before the utility regulatory commissions in Iowa, Illinois, and South Dakota.

2000 **Electricity Market Assessments**
Client: various American and European clients

Helped develop electricity market prices for regional electricity markets in North America (California, New England, Arizona/New Mexico, Louisiana) and Europe (Austria, Belgium, France, Germany, and the Netherlands). Mr. Taylor worked with project teams in the U.S. and Europe to develop simulation models and databases to forecast energy and capacity prices in the deregulating power markets.

1999 **Evaluation of New Resources**
Client: Florida Power Corporation

Helped prepare the FPC's RFP for long-term supply-side resources and assisted in the independent evaluation of responses. Mr. Taylor oversaw the review of FPC's computer simulations (in PROVIEW and PROSYM) of the proposals that were received. The project team also evaluated the proposals by using a response surface model to approximate the results that might be produced in the more detailed simulations. Mr. Taylor testified before the Florida Public Service Commission concerning his assessment of FPC's solicitation and the results of the analysis.

1998 **Evaluation of New Resources**
Client: Public Service of Colorado

Assisted the evaluation of proposals for PSCo's near-term 1999 resource additions and managed the complete third party evaluation of proposals for resources in the 2000-2007 time frame. Such resources included third-party facilities and power purchases, as well as company-sponsored interruptible tariffs. Mr. Taylor assisted with the development of the request for proposals and oversaw the evaluation of all responses. He and his team monitored subsequent negotiations with shortlisted bidders. Mr. Taylor testified before the Colorado Public Utilities Commission on the fairness of the solicitation and the results of the evaluation.

1997- **Evaluation/Negotiation of Transmission Interconnection Solicitation**
1999 Client: New Century Energies

Managed a solicitation for participation in a major transmission project interconnecting Southwestern Public Service (a Texas member of the Southwest Power Pool) and Public Service of Colorado (a member of the Western Systems Coordinating Council). As the first major inter-reliability-council transmission project in the era of open access, FERC required that SPS and PSCo solicit third-party interest in participation. This project required the development of an RFP and evaluation of responses for both equity participation and long-term transmission service for over 21 alternative high-voltage AC/DC/AC transmission projects. The evaluation focused on the costs and intangible risks of different transmission alternatives relative to the benefits and savings associated with increased economy interchange, avoided future generating capacity, and reductions in single-system spinning reserve and reliability requirements.

1996- **Evaluation/Negotiation of All-Source Solicitation**
1997 Client: Southwestern Public Service

Managed the evaluation of a broad array of responses to an all-source solicitation that was issued by Southwestern Public Service (SPS). Resources in the areas of conventional supply-side generation, renewable resources, off-system transactions, DSM, and interruptible loads were proposed. The evaluation entailed scoring the proposals for a variety of price and nonprice attributes. Mr. Taylor assisted Southwestern in its negotiations with the bidders and performed the detailed evaluation of the best and final offers.

1996- **Risk Assessment for 1,000-MW Solicitation**
1997 Client: Seminole Electric Cooperative

Managed the review and assessment of risks associated with responses to a 1,000-MW solicitation that was issued by Seminole Electric Cooperative. The evaluation entailed reviewing selected proposals' financial feasibility, performance guarantees, fuel supply plans, O&M plans, project siting, dispatching flexibility, and bidder qualifications.

1997 **Analysis/Testimony - Louisville Gas & Electric's Fuel Adjustment Clause**
Client: Kentucky Industrial Utility Customers

Performed a detailed examination of Louisville Gas & Electric's (LG&E) fuel adjustment clause and identified misallocated costs in the areas of transmission line losses and purchased power fuel costs. Mr. Taylor also critiqued LG&E's rate adjustment methodology and recommended closer scrutiny of costs associated with jurisdictional and non-jurisdictional sales. Mr. Taylor testified before the Kentucky Public Service Commission and presented the findings of his analysis.

1995 **Development of All-Source Solicitation RFPs**
Client: Southwestern Public Service

Managed the development of five RFPs that solicited resources in the areas of conventional supply-side generation, renewable resources, off-system transactions, DSM, and interruptible loads. The RFPs were issued by SPS as part of an all-source solicitation to identify resources that may be competitive with two generation facilities that SPS intended to develop.

1994 **Development of Competitive Bidding RFP**
Client: Empire District Electric Company

Based on knowledge gained from the review of dozens of other utility RFPs, developed a combined-cycle resource RFP for Empire District Electric Company. The project team was responsible for the RFP's entire development, including the development of scoring provisions for price and nonprice project attributes.

1993 **Selection of Developer for 25 MW Wind Facility**
Client: Northern States Power

Evaluated bids that were received by NSP in a solicitation for the development of a 25 MW wind facility in Minnesota. The proposals were scored and ranked through a point-based evaluation system that was developed prior to the solicitation. The scoring involved an assessment of operational and financial feasibility, power purchase pricing terms, construction schedules, and community acceptance issues.

Exhibit__AST-2

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Exhibit__AST-3, Page 1 of 3

Calculation of PPA Stability Rider (all values in $000)

line				2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
1	**Forecasted OVEC Net Benefits**			(15,952)	(5,461)	5,116	9,444	13,066	9,044	16,068	6,369	11,345	N/A
2	**Year 1 Average Expected Savings**			2,999	5,116	5,116	5,116	5,116	5,116	5,116	5,116	5,116	5,116
3	**Regulatory Account - Forecasted**												
4	Balance - Beginning of Year			-	18,951	29,528	29,527	25,199	17,248	13,320	2,367	1,114	(5,116)
5	Balance - End of Year			18,951	29,528	29,527	25,199	17,248	13,320	2,367	1,114	(5,116)	-
6	Balance - Average			9,476	24,240	29,528	27,363	21,224	15,284	7,844	1,741	(2,001)	(2,558)
			NPV										
7	Calculated Return		8,211	780	1,995	2,430	2,252	1,747	1,258	646	143	(165)	(211)
8	Levelized Return		8,211	769	1,312	1,312	1,312	1,312	1,312	1,312	1,312	1,312	1,312
9	WACC	8.23%											
10	**Initial PPA Stability Rider**			**(2,230)**	**(3,804)**	**(3,804)**	**(3,804)**	**(3,804)**	**(3,804)**	**(3,804)**	**(3,804)**	**(3,804)**	**(3,804)**
	(negative=credit)												

Exhibit__AST-3, Page 2 of 3

Calculation of PPA Stability Rider (all values in $000)

line		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
	Annual True-Up										
11	Actual OVEC Net Benefits *(illustrative)*	(18,952)	(3,461)	6,116	7,444	14,066	8,044	17,068	7,869	11,845	
12	Difference from Estimate	(3,000)	2,000	1,000	(2,000)	1,000	(1,000)	1,000	1,500	500	
	Amortization of Differences										
13	Calendar Year 2		1,000	1,000	1,000						
14	Calendar Year 3			(667)	(667)	(667)					
15	Calendar Year 4				(333)	(333)	(333)				
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								(333)	(333)	(333)
20	Calendar Year 9									(750)	(750)
21	Calendar Year 10										(500)
22	Net Benefit Adjustments	-	1,000	333	-	(333)	-	667	(333)	(750)	(1,583)
	Regulatory Account - True-up Adjustment										
23	Balance - Beginning of Year	-	3,000	-	(1,333)	667	-	1,000	(667)	(1,833)	(1,583)
24	Balance - End of Year	3,000	-	(1,333)	667	-	1,000	(667)	(1,833)	(1,583)	-
25	Balance – Average	1,500	1,500	(667)	(333)	333	500	167	(1,250)	(1,708)	(792)
26	Calculated Return	123	123	(55)	(27)	27	41	14	(103)	(141)	(65)

Exhibit__AST-3, Page 3 of 3

Calculation of PPA Stability Rider (all values in $000)

line			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
27	Initial Annual Rider *(line 10)*		(2,230)	(3,804)	(3,804)	(3,804)	(3,804)	(3,804)	(3,804)	(3,804)	(3,804)	(3,804)
28	Net Benefit Adjustments *(line 22)*		-	1,000	333	-	(333)	-	667	(333)	(750)	(1,583)
29	Return on Regulatory Account - True-up Adj		-	123	123	(55)	(27)	27	41	14	(103)	(206)
	(line 26 – one year lag, except for final year)											
30	Revised Annual Rider		(2,230)	(2,680)	(3,347)	(3,858)	(4,164)	(3,776)	(3,096)	(4,123)	(4,656)	(5,593)
31	AEP Ohio Percentage	10.0%										
32	**Final PPA Stability Rider (Customer Portion)**		**(2,007)**	**(2,412)**	**(3,012)**	**(3,473)**	**(3,748)**	**(3,399)**	**(2,786)**	**(3,711)**	**(4,191)**	**(5,033)**

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Summary: Testimony Direct Testimony and Exhibits of Stephen J. Baron and Alan S. Taylor (Public Version) on behalf of the Ohio Energy Group (OEG). electronically filed by Mr. Michael L. Kurtz on behalf of Ohio Energy Group