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Case No. 14-1297-EL-SSO

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PUCO Case Caption: In the Matter of the Application
of Ohio Edison, The Cleveland Electric Illuminating
Company, and The Toledo Edison Company
for Authority to Provide for a Standard Service
Offer Pursuant to R.C. 4928.143 in the Form
of an Electric Security Plan.

List of exhibits being filed:

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Date Submitted: 10/22/2015

1 BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO

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In the Matter of the :

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Application of Ohio Edison:

Company, The Cleveland :

Electric Illuminating :

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Company, and The Toledo :

Edison Company for :

Case No. 14-1297-EL-SSO

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Authority to Provide for :

a Standard Service Offer :

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Pursuant to R.C. 4928.143 :

in the Form of an Electric:

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Security Plan. :

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PROCEEDINGS

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before Mr. Gregory Price, Ms. Mandy Chiles, and

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Ms. Megan Addison, Attorney Examiners, at the Public

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Utilities Commission of Ohio, 180 East Broad Street,

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Room 11-A, Columbus, Ohio, called at 9:00 a.m. on

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Thursday, October 8, 2015.

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VOLUME XXVI

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STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 14-E-0270 - Petition for Initiation of Proceeding to
Examine Proposal for Continued Operation of
R.E. Ginna Nuclear Power Plant.

ORDER DIRECTING NEGOTIATION OF A
RELIABILITY SUPPORT SERVICE AGREEMENT
AND MAKING RELATED FINDINGS

Issued and Effective: November 14, 2014



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STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service
Commission held in the City of
Albany on November 13, 2014

COMMISSIONERS PRESENT:

Audrey Zibelman, Chair
Patricia L. Acampora
Garry A. Brown
Gregg C. Sayre
Diane X. Burman

CASE 14-E-0270 - Petition for Initiation of Proceeding to
Examine Proposal for Continued Operation of
R.E. Ginna Nuclear Power Plant.

ORDER DIRECTING NEGOTIATION OF A
RELIABILITY SUPPORT SERVICE AGREEMENT
AND MAKING RELATED FINDINGS

(Issued and Effective November 14, 2014)

BY THE COMMISSION:

BACKGROUND

In a petition filed on July 11, 2014, R.E. Ginna Nuclear Power Plant, LLC (Ginna, the Petitioner) requests initiation of a proceeding to examine a proposal for continued operation of the R.E. Ginna Nuclear Power Plant (the Ginna Facility). Specifically, Ginna seeks: (1) a finding that continued operation of the Ginna Facility is necessary for electric service reliability; (2) a determination that its Petition satisfies the requirements for giving notice of a proposed retirement; and, (3) an Order directing Rochester Gas and Electric Corporation (RG&E) to promptly negotiate and file a Reliability Support Services Agreement (RSSA) for the continued operation of the Ginna Facility in support of electric system reliability on the bulk transmission system and in RG&E's service territory. The Petitioner describes the Ginna Facility

as a 581 MW single-unit pressurized water reactor located along the south shores of Lake Ontario, in Ontario, New York, approximately 20 miles northeast of Rochester, New York. In 2004, Ginna relates, the federal Nuclear Regulatory Commission extended the Facility's license to operate to September 2029.¹

Ginna, a subsidiary of Constellation Energy Nuclear Group, LLC (Constellation), sold a majority of the Facility's output to RG&E under a purchase power agreement (PPA) until that agreement expired on June 30, 2014. Since then, Ginna has operated as a merchant generator selling into the wholesale markets that the New York Independent System Operator, Inc. manages.

Ginna alleges that revenues the Facility has earned in recent years have been insufficient to cover the costs of its operation, and it forecasts that expected revenues will remain below the continuing costs of operation into the foreseeable future. As a result of these economic circumstances, Ginna reports, it met separately with individual Commissioners, Department of Public Service Staff (Staff), RG&E, and the NYISO to discuss its evaluation of the economic forces it perceives as driving its Facility into retirement. On February 21, 2014, Ginna, RG&E, and the NYISO entered into a reliability study agreement, and in conformance with that agreement, the NYISO produced the 2014 Reliability Study on May 12, 2014,² where it found that the retirement of Ginna would result in bulk transmission system and non-bulk local distribution system reliability violations in 2015 and 2018, the two years studied.

¹ Issuance of Renewed Facility Operating License No. DPR-18 for R.E. Ginna Nuclear Power Plant, Operating License, Nuclear Regulatory Commission, (issued May 19, 2004).

² New York Independent System Operator, Additional Reliability Study for Exelon Corporation - Final Report, (May 12, 2014) (Reliability Study).

When Ginna filed its Petition, RG&E simultaneously filed a letter confirming entry into the reliability study agreement for the purpose of determining what, if any, adverse reliability risks would exist if energy and capacity from the Ginna Facility were not available. RG&E also explains it joined in conducting the 2014 Reliability Study and supports the analysis demonstrating that the permanent retirement of the Ginna Facility would result in bulk system and local reliability needs in the NYISO control region for the greater Rochester area in 2015 and 2018.

In conformance with State Administrative Procedure Act (SAPA) §202(1), notice of the petition was published in the State Register on July 30, 2014.³ The SAPA §202(1)(a) period for submitting comments in response to that notice expired on September 15, 2014. Comments objecting to the relief requested were timely submitted by: Multiple Intervenors (MI), Alliance for A Green Economy (AAGE), the Entergy Entities,⁴ Indicated New York Transmission Owners (Indicated Owners),⁵ the NRG Companies,⁶ and New York City (NYC, the City) (together, the Opponents).

³ After the deadline expired, Citizens Environmental Coalition filed a comment on September 25, 2014; that comment will not be considered because it is untimely and does not advance the record in this proceeding.

⁴ The Entergy Entities are: Entergy Nuclear Fitzpatrick, LLC, Entergy Nuclear Indian Point 2, LLC, Entergy Indian Point 3, LLC, and Entergy Nuclear Operations, Inc.

⁵ The Indicated New York Transmission Owners are: Central Hudson Gas and Electric Corporation, Consolidated Edison Company of New York, Inc., Niagara Mohawk Power Corporation d/b/a National Grid, and Orange and Rockland Utilities, Inc.

⁶ The NRG Companies are: NRG Power Marketing, LLC, GenOn Energy Management, LLC, Arthur Kill Power LLC, Astoria Gas Turbine Power LLC, Dunkirk Power LLC, Huntley Power LLC, NRG Bowline LLC and Oswego Harbor Power LLC.

Over 220 timely public comments, including eight from public officials, were received in support of the petition.

POSITIONS OF THE PARTIES

The Petition

Ginna begins by emphasizing that, in the 2011, 2012 and 2013 calendar years preceding its petition, it incurred cumulative losses at the Ginna Facility amounting to more than \$100 million. Additionally, Ginna complains, its parent, Constellation, has not been compensated for any operational risk or earned any return on its investment over this period. These circumstances, Ginna explains, motivated its meetings with individual Commissioners, RG&E, Staff, and the NYISO to discuss its consideration of retirement.

Ginna requests that the Commission find the continued operation of the Ginna Facility is needed to preserve electric system reliability based upon the findings of the 2014 Reliability Study RG&E and NYISO conducted. Ginna notes that the need for the Facility will continue until RG&E's proposed Rochester Area Reliability Project (the RARP) enters service. The RARP consists of 1.9 miles of new 345 kV transmission line, 23.6 miles of new or rebuilt 115 kV transmission line, a new 345 kV/115 kV substation, and equipment upgrades at several existing substations, all in Monroe County, and equipment upgrades at two substations in Niagara County.⁷ The RARP is intended, in part, to serve the electricity needs of the Rochester area if a long-term outage were to occur at the Ginna Facility. Ginna asserts that no alternatives have been identified to replace the full

⁷ Case 11-T-0534, Application of Rochester Gas and Electric Corporation for a Certificate of Environmental Compatibility and Public Need for the Construction of the "Rochester Area Reliability Project, Application (filed Sept. 30, 2011).

electricity output of the Ginna facility until at least October 2018, when the RARP is scheduled for completion.

Lastly, Ginna notes that substantial adverse impacts on local electric reliability could be experienced, in addition to the impact on reliability of the bulk power transmission system, if the Facility were to close. Ginna also points to the economic and environmental benefits that the Facility brings to the State and local community. Quantifying the reductions in emissions that would otherwise be released from the alternative fossil fuel burning generator that would replace the Facility, Ginna states that continued operation would prevent the emission of 1,000 tons of nitrogen oxide and 1,040 tons of sulfur dioxide annually. The carbon emissions its operations would avoid, Ginna continues, assist New York State in satisfying its Regional Greenhouse Gas Initiative (RGGI) carbon-reduction goals.

Based upon the foregoing, Ginna requests that the Commission find a reliability need justifies continued operation of the Facility. In addition, Ginna asks that the petition itself be deemed satisfactory to meet the requirements for giving notice of generation unit retirements established in the Generation Retirement Order.⁸ Ginna argues that the petition notice, along with its communications with individual Commissioners, Staff, RG&E and NYISO, constitute the giving of notice sufficient to satisfy the policies behind the requirements established in the Generation Retirement Order.

According to Ginna, that notice requirement was adopted so that there would be sufficient time to investigate system reliability and community impacts before a generation

⁸ Case 05-E-0889, Generation Unit Retirements, Order Adopting Notice Requirements of Generation Unit Retirements (issued December 20, 2005).

facility actually left service. Since its petition and the 2014 Reliability Study afford the opportunity to examine those issues, Ginna maintains, no further notice is required.

Analysis of Comments

A. Multiple Intervenors

In a motion filed on July 29, 2014, and in separate comments filed on September 15, 2014, Multiple Intervenors (MI) argues that the Petition should be dismissed because it fails to meet the requirements for giving notice of a generation facility retirement. Those requirements, MI insists, compel owners of generating facilities to file a written notice, if a permanent shutdown is planned due to economic reasons,⁹ at least 180 days prior to the time retirement is effectuated.¹⁰ MI believes that it would set a poor precedent if Ginna's Petition were accepted as a notice of retirement.

MI contends that Ginna's actions are insufficient to serve as notice of retirement. MI dismisses the action Ginna took as substitutes for written notice. Meeting separately with individual Commissioners, Staff, RG&E and NYISO, MI maintains, is not compliance because other potentially interested parties were not informed of the meetings or the communications that took place there. Moreover, nowhere in Ginna's recounting of its communications, MI remarks, does Ginna promise to retire the Facility. The petition itself, MI protests, is also inadequate as notice because Ginna did not undertake there a binding commitment to retire the Facility, much less to retire it by a specific date. According to MI, Ginna's affirmation in its petition that its management will recommend to Constellation

⁹ Case 04-E-0030, Declaratory Ruling on Regulatory Regime, Order Providing for Lightened Regulation of Nuclear Generation Facility Owner (issued May 20, 2004), p.6.

¹⁰ Generation Retirement Order, pp. 14-15.

that the Facility should be retired falls far short of a commitment to actually retire.

MI also argues that the submission of the NYISO Reliability Study is not a substitute for giving notice. Preparation of the study, MI contends, has no bearing on satisfaction of the notice requirements.

The notice requirements, MI asserts, are more than a mere formality. Notice must be given in accordance with the Generation Retirement Order's requirements, MI maintains, so that those affected by the retirement are afforded time to devise measures for mitigating any adverse impacts that might attend a shutdown. Moreover, MI believes, absent receipt of the notice of retirement, the NYISO cannot notify market participants of the planned retirement. If the form of Ginna's notice were accepted, MI argues, the reasons for the public notice requirement would be frustrated -- that is, market participants would be denied with the opportunity to propose solutions to meet the reliability need. These policies, MI maintains, are at the heart of both the Generation Retirement Order and the separate notice requirements provided for in the Ginna Light Regulation Order.¹¹

MI believes that the notice is essential for another reason because it is the evidence that an RSSA is the only available solution to a reliability need. Absent strict adherence to the notice requirement, MI fears, the doors will open for any generator to seek an RSSA without showing that such an agreement, which MI believes should be a last resort employed

¹¹ Case 04-E-0030, R.E. Ginna Nuclear Power Plant LLC, Order Providing For Lightened Regulation of Nuclear Generation Facility Owner (issued May 20, 2004).

only when reliability cannot be otherwise preserved, is appropriate.¹²

In its comments, MI builds upon its arguments in its motion. MI would draw a distinction between planned and proposed retirements, arguing that a mere proposal to retire is insufficient to justify entry into a RSSA, which should be limited to instances where retirement is certain. That certainty can be established, MI maintains, only where an exact date on which retirement will occur has been firmly established.

An RSSA, MI emphasizes, is a last resort that should be deployed only when other alternatives to preserving reliability are not feasible. Directing entry into an RSSA, MI asserts, is not appropriate unless the generation facility will clearly be forced into retirement absent the RSSA, because without such a showing the RSSA may not be needed. Only that strong showing of need, MI declares, justifies an RSSA, when it is ratepayers that will be forced, through increases in the utility rates they pay, to fund the out-of-market costs incurred under the RSSA.

Criticizing the 2014 Reliability Study, MI complains that it is deficient as compared to other reliability studies relied upon when other RSSAs were granted. According to MI, the Study is not independent, because Ginna commissioned it and the data relied upon is flawed. In particular, MI asserts, only the years of 2015 and 2018 chosen by Ginna are analyzed in the 2014 Reliability Study, when other reliability studies analyze an entire consecutive period of years. The Study, MI adds, must also be updated with the most recent data from 2014, instead of the 2013 data on which it relies.

¹² AAGE voices states its support for MI's Motion to Dismiss and states that it joins in MI's reasoning.

B. The Entergy Entities

The Entergy Entities maintain that the Petition should be denied on procedural and substantive grounds. They state that the notice was improper, and without adequate notice, the record does not include sufficient information to identify the scope, extent or duration of a reliability need stemming from a Ginna retirement.

If the Commission accepts the Petition as constructive notice, the Entergy Entities believe that the Commission should ask the NYISO to post a retirement notice on its website and then request the NYISO and RG&E to conduct a thorough and comprehensive reliability study. The 2014 Reliability Study described in the Petition, Entergy contends, was not as comprehensive as the NYISO normally produces upon request following a retirement notice. In prior cases, Entergy maintains, the NYISO has performed studies over a consecutive five-year period; here the reliability study was limited to only two years -- 2015 and 2018. Additionally, Entergy believes the analysis of local reliability needs was inadequate.

Entergy also opposes the Petitioner's request that a completed and binding RSSA be entered into and then filed for the Commission's review. In the two cases previously where RSSAs were required, Entergy protests, term sheets were filed and time was allotted for public comment on them before an RSSA was executed.

Moreover, the Entergy Entities maintain that an RSSA should be a last resort to resolving a reliability issue. When prior RSSAs were proposed, they claim, the Commission properly sought alternatives to an RSSA more vigorously than it did here.

The Entergy Entities further argue that the Commission lacks the authority to compel RG&E and Ginna to enter into an RSSA because that action would be preempted by the exclusive

jurisdiction over wholesale sales of electricity and capacity granted to the Federal Energy Regulatory Commission (FERC) under the Federal Power Act (FPA). If an RSSA is warranted, Entergy asserts, a petition requesting that relief should be submitted to FERC for its consideration because that relief falls within its exclusive purview.

C. The Indicated Owners

The Indicated Owners request that the Commission reject the Petition. They argue that a proper notice of retirement must be distributed to all New York wholesale market participants, so that they then have an opportunity to propose solutions. In particular, the Indicated Owners maintain that the mere suggestion of a potential retirement is inadequate either to justify an RSSA or to satisfy the requirements of the Ginna Light Regulation Order and the Generation Notice Order. As a result, the Indicated Owners support the arguments set forth in MI's Motion.

D. The NRG Companies

The NRG Companies also argue that the Petitioner's notice of retirement is inadequate. The NRG Companies join with the Entergy Entities and the Indicated Owners in claiming that the Generation Retirement Order procedures were intended to provide all parties with notice and information about potential retirements. One primary means of communicating that notice, the NRG Companies note, is through the NYISO website. But, the NRG Companies protest, the NYISO has not posted notice of Ginna's Petition.

The NRG Companies contend that the NYISO's evaluation of alternative solutions for identified reliability needs is obstructed where adequate notice is not given. NRG maintains that if the Petition is accepted, a reliability study should be

ordered that corrects the deficiencies in the 2014 Reliability Study already conducted.

E. NYC

NYC raises the broader concern of what it perceives as a growing reliance upon RSSAs. The City believes that when competition was introduced -- for the purpose of replacing utility owned generation plants at rate based costs with independently owned generation plants at market based prices -- the expectation was that older, less efficient generation plants would eventually retire and be replaced with more economically and environmentally beneficial plants. The City notes that, recently, the Commission confronted three circumstances where generation plants, including Ginna, posed electric system reliability problems if they were to retire, and that the first two instances resulted in ratepayer support for the generators through RSSAs.¹³ This trend, the City propounds, undermines the purposes of competitive wholesale generation markets.

Additionally, NYC supports MI's Motion to Dismiss. Ginna's request that its petition be accepted as notice of retirement, the City protests, should be denied because it undermines the purpose of the notice requirement, which is to avail to other market participants the opportunity to offer alternative solutions to a reliability issue resulting from the closure of a generator. Without a specific date for retirement, the City argues, any action on this petition would be based on mere speculation, enabling Ginna to obtain an RSSA without substantiating the basis for such extraordinary relief and

¹³ Case 12-E-0136, Dunkirk Power LLC, Order Deciding Reliability Issues and Addressing Cost Allocation Recovery (issued August 16, 2012); Case 12-E-0400, Cayuga Operating Company LLC, Order Deciding Reliability Issues and Addressing Cost Allocation and Recovery (issued December 17, 2012) and Order Deciding Reliability Need Issues and Addressing Cost Allocation and Recovery (issued January 16, 2014).

without showing there are no alternatives superior to that relief.

Electric distribution utilities, the City insists, should be aware of and prepare for any reliability issue arising within their service territory. The City charges the Commission with using that information to create a proper platform for the success of competitive generation markets. NYC concludes that RSSAs are not a substitute for a functioning competitive markets that would support the goals anticipated upon utility deregulation and advance the goals stated in the Commission's Reforming the Energy Vision (REV) proceeding.¹⁴

F. Public Comments

About 220 timely public comments have been received.¹⁵ These comments included letters from the following government officials: U.S. Representatives Dan Maffei and Tom Reed, Senators George Maziarz and Patty Ritchie; Assemblymembers Robert Oaks and William Barclay; Chairman James Hoffman of the Wayne County Board of Supervisors; Monroe County Executive Maggie Brooks; Supervisor John Smith and Councilmember Michael Melino of the Ontario Town Board; and, the Town Board of Palmyra. The rest of the public comments were from individuals who filed letters in support of Ginna. Many came from employees at Ginna, who expressed pride in their work and in the professionalism of the facility's workforce.

The public comments generally approved of the operations of Ginna Facility in the Rochester region, and expressed concern if the facility were to close. One commentor

¹⁴ Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision.

¹⁵ Numerous untimely public comments, making the same points as the timely comments, were also received.

referred to a recent poll that showed a 97% acceptability rating for the Ginna plant in the region.¹⁶

Ginna, the public comments indicate, is an economic pillar within the local community, employing a workforce of 700 people that expands by an additional 800 - 1,000 contractual workers during refueling. The plant supports the property tax base in the local community and is the largest tax payer in Wayne County. The specialized workforce is well paid, and lends its own strong support to the tax base. In a rural community, this tax base funds quality educational and recreational opportunities for residents. In addition to the economic benefits, Ginna gives back to its home community; it is the largest contributor to the United Way in Wayne County, and supports other local charities. Lastly, Ginna enriches the community through the diversity of its employees.

Employees of Ginna stated that they take environmental stewardship very seriously, and that the facility is not only clean, but is also quiet. The employees emphasize safety is a paramount value at the facility, and many, as evidence of their trust in the safety of Ginna, announced that they live within a short distance of the Facility.

The Director of Disaster Preparedness for the Wayne County Emergency Management Office wrote expressing his support, and stating that his office has an excellent relationship with Ginna based on communicating with it on a regular basis. He calls Ginna a good neighbor that is vital to emergency management in terms of grid reliability and preparation for hazardous events.

Finally, many comments reported that benefits attach to the electricity supplied from the Facility, in that the electricity is produced from a reliable and stable resource with

¹⁶ Public Comment of Sue DeVito (September 8, 2014).

little or no price fluctuation due to short term fuel procurement challenges. The Facility, they add, lends fuel diversity to New York's energy portfolio, which reduces reliance upon any one resource, and thereby enhances reliability. Many of the comments also noted, that, as a nuclear facility, Ginna has a zero carbon footprint.

G. Ginna's Response

On August 6, 2014, Ginna filed a response to MI's Motion to Dismiss. Ginna states that it met all of the objectives of the Commission's retirement and other policies. It stressed that the already-completed 2014 Reliability Study confirms a need for continued operation at the Ginna Facility. Disputing MI's analysis of the retirement notice requirements, Ginna notes that those requirements are not set forth in a statute and instead were imposed in the Generation Retirement Order. Consequently, Ginna asserts, the Commission may depart from the requirements if it states valid reasons for doing so, in conformance with generally-accepted principles of New York administrative law.

According to Ginna, providing written notice of a definitive retirement date for the Ginna Facility would disrupt rather than advance the policies stated in the Generation Retirement Order. Selection of an exact date, Ginna claims, would only constrain evaluation of an RSSA agreement to an artificially-determined period for conducting the analysis. So long as it shows that retirement is the appropriate response to economic conditions, and otherwise meets the policies behind the notice requirements, Ginna maintains it need not select a specific date. Ginna believes it has satisfied those policies, through the 2014 Reliability Study showing its facility is needed and the reasons presented in its petition justifying entry into an RSSA.

DISCUSSION AND CONCLUSION

In order for Ginna to obtain an RSSA, it must first show that its Facility must remain in operation in order to preserve electric system reliability. Second, it must demonstrate that it has provided a notice of retirement that complies with the Generation Retirement Order policies,¹⁷ by affording sufficient time to address adverse impacts that might attend retirement and to investigate alternatives to continued operation for preserving reliability. Third, it must show that the RSSA is superior to alternatives as a means for preserving reliability.

Ginna has demonstrated that its facility is needed for system reliability purposes and that its notice should be deemed satisfactory because it serves the purposes of the generation retirement requirements and policies. Given the size, location, and importance of the Ginna Facility as a generation resource, Ginna has also justified directing RG&E to commence negotiations over for an RSSA, albeit further procedures are required to ensure that an RSSA is the best and most cost-effective alternative for maintaining reliability.

Reliability NeedA. The 2014 Reliability Study

The NYISO's 2014 Reliability Study demonstrates that there would be a negative impact on the reliability of the New York bulk electric transmission system and in the local Rochester electric distribution region during 2015 and 2018, respectively, if Ginna ceased operations before the RARP is scheduled to enter service. The system representation analysis

¹⁷ Because the Ginna Light Regulation Order provides for the same six-month notice period as the Generation Retirement Order, both Orders will be considered directed to the same purpose.

was developed based on the NYISO's 2013 FERC 715 filing,¹⁸ and the study was conducted in accordance with applicable North American Electric Reliability Corporation (NERC) Reliability Standards, Northeast Power Coordinating Council (NPCC), Design Criteria, New York State Reliability Council (NYSRC) Reliability Rules and Procedures, and NYISO planning and operation practices.¹⁹ Completed and issued on May 12, 2014, the study is timely, and the analyses of 2015 and 2018 are sufficient to show an immediate and continuing need for the Ginna Facility to preserve bulk transmission system and local distribution system reliability.

B. Objections to the 2014 Reliability Study

The objections to the 2014 Reliability Study that the Opponents present are not persuasive. Primarily, they complain that only two years, 2015 and 2018, were analyzed in the Study, when the analysis should have covered an entire period of consecutive years. There is, however, no such requirement. The two years selected properly bound the period during which the RARP transmission project now under development will not be available to support reliability if Ginna were absent. Moreover, that the plant is needed in 2015 and 2018 is sufficient to show that it should remain in operation for the entire period.

Even if it could be shown that the plant were not needed in 2016 and 2017 -- a showing that the Opponents have been unable to make -- reliability could only be preserved by running the plant in 2015, mothballing it for 2016 and 2017, and then returning it to operation in 2018. But, since Ginna is a nuclear facility, mothballing it over a two year period and then returning it to service poses risks that likely would far

¹⁸ 2014 Reliability Study at 5.

¹⁹ 2014 Reliability Study at 7.

outweigh any savings that could be derived from the mothballing. The costs of mothballing would be significant; the techniques and processes required would be complex; and, many skilled employees would have to be retained so that sufficient qualified personnel, not readily found in the short-term labor market, would be available to restart the Facility.

The Opponents also criticized the use of 2013 data. For a Study promulgated in May 2014, however, use of that data was clearly appropriate. The Opponents have not shown that updating the data would result in any material change to its outcome. Nor is the fact that Ginna contracted for the Study prove it is biased; the NYISO, as discussed above, responded to the inquiry regarding the effect of the closure of the Ginna Facility by conducting the 2014 Reliability Study in conformance with its usual methods. It produced a result that meets all applicable NERC, NPCC and NYSCC standards and is persuasive as well.

C. Conclusion

Therefore, the findings made in the 2014 Reliability Study are accepted. They establish the reliability need for continued operation of the Ginna Facility that is the essential prerequisite to negotiating an RSSA.

Adequacy of the Notice

According to the Opponents, Ginna must set a specific, binding date for the retirement of the Facility in order to comply with the Generation Retirement Order and to justify entry into an RSSA. Ginna has not identified such a specific date, notwithstanding the Generation Retirement Order requirement that notice be given 180 days before a facility may cease to operate.

A. The Notice Policies

In the Generation Retirement Order, however, the Commission explained that a 180-day period for giving notice of

retirement before it can be effectuated represents "the minimum period that NYISO indicates as adequate to identify and resolve reliability concerns."²⁰ Therefore, the purpose of the 180-day period is to determine whether any adverse impacts on reliability might arise upon the closure of a generation facility, and if so, to afford time to develop and implement alternatives.

The emphasis the Opponents would place upon the selection of a specific retirement date is misplaced. As Ginna points out, the Commission has the authority to modify the policies it establishes when doing so is reasonable and in the public interest. Instead of rigid adherence to a generalized 180-day specification that does not assist in the evaluation of these unusual circumstances, the issue here is effectuation of the policies established in the Generation Retirement Order. As discussed in that Order, the 180-day requirement is intended to assure sufficient time to determine if a retirement has an adverse impact on reliability, and to investigate alternatives for alleviating any such impacts.

B. Compliance With the Notice Policies

1. Effect of the 2014 Reliability Study

In most circumstances, a reliability study is not commenced until the notice is received. Here, however, the 2014 Reliability Study was filed at the same time as Ginna's petition. As a result, there was no need to request a study and allow for time to prepare and examine it after its receipt before determining that a need existed. That process alone can take months, and the availability of the 2014 Reliability Study that was provided when at the time the petition was filed therefore considerably foreshortens the need for a 180-day period.

²⁰ Id. at 15.

Moreover, as discussed above, the 2014 Reliability Study demonstrates the Ginna Facility is currently needed for reliability purposes. An RSSA, however, cannot be negotiated and filed prior to January 2015, and further procedures will be needed before it can be approved and take effect. If Ginna had filed a 180-day notice as of the July 11, 2014 date of its Petition, the notice period would have ended in January 2015, so the notice period has, in effect, been met. Finally, the Commission possesses the authority to waive the notice period for the purpose of either extending it or shortening it, and that authority extends to granting relief from the notice period here tailored to these unusual circumstances, which include impacts related to the size, location, specialized workforce, and nuclear fueling of the Ginna Facility.²¹

2. Examination of Alternatives

The other function of the 180-day notice period is to afford sufficient time to examine alternatives if a retirement poses adverse impacts to reliability or otherwise raises public interest considerations. The Opponents complain that Ginna has not afforded them sufficient time to propose alternatives to an RSSA because of its failure to select a retirement date. Any such alternative, however, could have been proposed in response to the petition within the comment period established for those responses, because the 2014 Reliability Study came with the Petition, and interested parties did not have to await its preparation, as normally would occur upon a 180-day retirement notice. No such alternative was presented.

²¹ See, e.g., Case 10-E-0553, Project Orange Associates LLC, Order Accepting Notice of Retirement and Making Other Findings (issued December 21, 2010); Case 08-E-0016, Onondaga Cogeneration, L.P., Order Excusing Late Filing (issued March 25, 2008); Case 14-E-0117, Danskammer Energy LLC, Order Approving Transfer and Making Other Findings (issued June 27, 2014).

Moreover, on October 6, 2014, RG&E issued a Request for Proposals (RFP), soliciting replacements for the capacity and electricity generated at the Ginna Plant. To the extent that Opponents complain that alternatives to an RSSA for Ginna were not sufficiently examined as contemplated in the Generation Retirement Order, the RFP corrects for that deficiency. As a result, the policies underpinning the Generation Retirement Order have been furthered. As discussed further below, however, RG&E must coordinate evaluation of the responses to the RFP with the negotiation of an RSSA for Ginna.

C. Other Factors Affecting Notice

Other factors also justify accepting Ginna's notice without selecting a specific retirement date at this time. The fact that Ginna is a nuclear facility creates a unique set of issues, both regulatory and practical. As a nuclear facility Ginna, must comply with the Nuclear Regulatory Commission's (NRC) rules, which require Ginna to submit to the NRC a written certification of a determination of retirement stating the date that power generation will permanently cease.²² This provision protects the public interest even without the selection of a specific retirement date under the Generation Retirement Order.

Once such a specific retirement date has been noticed, NRC would consider Ginna to be within five years of the projected end of operations, compelling submission of a preliminary decommissioning cost estimate,²³ which must include plans for accomplishing decommissioning.²⁴ Ginna would also be required to provide a Post Shutdown Decommissioning Activities Report (PSDAR),²⁵ which is relied upon to ensure there is

²² 10 C.F.R. §§50.82(a)(1)(i) and 50.4(b)(8).

²³ 10 C.F.R. §50.75(f)(3).

²⁴ 10 C.F.R. §50.75(f)(5).

²⁵ 10 C.F.R. §50.82(a)(4)(i).

adequate assurance of funding for decommissioning. These protections remain in place regardless of a retirement date selected under the Generation Retirement Order.

In addition, if Ginna, as a nuclear plant owner, were to specify a definitive retirement date, it risks losing the specialized talent of the personnel within its employ. Nuclear physicists, engineers, and other highly technical professionals are in demand, and may leave for other work if their job security appears at risk. Continuing operation of the Facility could become subject to unnecessary stresses if those employees are lost, notwithstanding reliability need or profitability.

Selecting a specific retirement date would also have an adverse impact on the local community. As the public comments establish, the Ginna facility and its employees are the linchpin of the economic health of the local Wayne County community, and its economic benefits are felt throughout the Rochester region. Identifying a date at which retirement would occur would require many municipalities and businesses that depend upon the economic activity the Ginna Facility generates, either directly or indirectly, to commence planning for substantial reductions in revenues. Steps might be taken that are unnecessary and counterproductive in order to prepare for a deadline that is artificially set at a 180-day period. This impact on the public interest is best avoided.

D. Conclusion

Therefore, Ginna has shown that it has provided proper notice of retirement, under the Generation Retirement Ginna Light Regulation Orders, as properly interpreted. Having commenced this proceeding and given notice of retirement through a petition without selecting a specific retirement date, however, Ginna is reminded that it cannot cease operations without the Commission's permission. Under most circumstances,

that permission is deemed granted if the 180-day period expires without Commission action, because, after giving the notice, nothing prevents retirement once the period has passed. Since there is no 180-day period here, however, Ginna may not cease operation without written permission. This requirement is sufficient to protect the public interest and is a satisfactory substitute for the selection of a 180-day retirement period at the time the petition was filed.²⁶

Entry into an RSSA

As discussed above, Ginna has justified entry into RSSA negotiations because retention of its Facility is necessary for the preservation electric system reliability. Moreover, by affidavit dated October 23, 2014, Ginna now certifies that the revenues it expects from the sale of capacity and energy into NYISO markets will not be sufficient to cover the costs of continued operation, which includes new capital investments that must be made. Absent an RSSA, the Facility would be retired as soon as would be practicable. This affirmation buttresses the conclusion that the commencement of negotiations over an RSSA for the Ginna Facility is warranted.

With the essential reliability need predicate to obtaining an RSSA satisfied, it may be noted that an RSSA is otherwise in the public interest, in that loss of the Ginna Facility would adversely affect the local economy, and the adverse impact would ripple out into the surrounding region as well. Moreover, the absence the Facility's nuclear generation would inevitably lead to an increase in fossil fuel use; renewables and energy efficiency cannot replace all of its generation if it were lost. As a result, Ginna's retirement

²⁶ Ginna may apply for the requisite permission during the course of this proceeding, or it may be selected subject to Commission approval by specifying a date in the RSSA.

would adversely affect air quality in New York and make compliance with RGGI more difficult.

A. RSSA Costs

The Opponents, however, raise important issues concerning the cost of the RSSA, which on one hand is recovered from ratepayers but on other hand is necessarily tied to the profitability of the Ginna Facility. The Opponents maintain that Ginna has failed to adequately demonstrate that forecasted revenues will be insufficient to meet ongoing costs, especially since Ginna did not select a retirement date by which it must cease operations in order to avoid incurring additional losses.

Moreover, of critical importance in negotiating an RSSA is the price that will be paid for the reliability attributes purchased. In connection with that analysis, RG&E is expected to investigate thoroughly the economic circumstances Ginna confronts so that the value of those reliability attributes is not overstated. The review of the economic circumstances that will be conducted in arriving at an RSSA price for the reliability attributes will necessarily answer questions on economic viability that the Opponents have posed. As a result, RG&E and Ginna are expected to support their positions on an RSSA with the economic analysis that will enable the Commission to determine the extent to which RSSA pricing is required. Additionally, it is expected that any RSSA resulting from these negotiations should address impacts of changes in economic circumstances and concomitant market electric prices on Ginna over time.

B. The Effect of the RFP

As discussed above, RG&E must also coordinate its RFP process with the negotiation of the RSSA. Initial responses to the RFP are due on November 21, 2014 and RG&E expects to short list the qualified bidders by December 19, 2014. RG&E shall

share the initial responses with Staff by November 25, 2014 and shall report its analysis of the short list to Staff by December 23, 2014. The sharing and reporting will indicate if there are proposals that could preserve reliability on a cost-effective basis without Ginna during the period that would be covered under the RSSA.

To the extent that alternatives proposed through the RFP might affect entry into an RSSA, or the period for which the RSSA remains in effect, RG&E, in consultation with Staff, would evaluate if viable, cost effective substitutes for the Facility, including generation, transmission, and other resources, would be available and could commence operations in a timely fashion. If it is determined that alternatives could affect negotiation of the RSSA, RG&E should redirect the RSSA negotiations to accommodate the alternatives. For example, an alternative might reduce the time period for which the Ginna Facility is needed, resulting in a shorter term for the RSSA.²⁷

C. Conclusion

Since Ginna has shown there is a reliability need for its Facility; that it has given proper notice of the potential retirement of the Facility; and, that its economic circumstances warrant commencement of negotiations over an RSSA, RG&E is directed to participate in those negotiations with Ginna. The negotiations shall conclude with the filing of an RSSA by January 15, 2015.²⁸ If the parties cannot agree on the terms,

²⁷ Given the size, location and reliability of the Ginna Facility, and that it is currently needed, it is unlikely that any alternative proposed could eliminate entirely reliance upon an RSSA here, at least during the earlier portion of the RSSA term.

²⁸ The Entergy Entities' claim that an RSSA term sheet must be prepared and evaluated before an RSSA contract can be entered into has no basis in law or fact and is rejected.

they shall file so much of the RSSA upon which they do agree, while proposing alternatives to provisions in dispute.

Federal Preemption

The Entergy Entities assert that RSSA agreements fall squarely within the area over which FERC has exclusive jurisdiction, and could pose an obstacle to FERC's implementation of the FPA, and so the Commission is preempted from requiring RG&E to enter into an RSSA with Ginna. As is well established, however, the Commission is responsible for ensuring "safe and adequate service" by "electric corporations," including independent generation owners.²⁹ In order to fulfill its responsibility, the Commission takes an active role in reviewing whether a proposed retirement of an independently owned generation facility may adversely impact reliability.

Moreover, to the extent that FERC has addressed this issue in New York, it has recognized the Commission's role in protecting the public interest where a generation facility retirement calls electric system reliability into question. The NYISO tariff states that, when a threat to electric reliability arises, "[t]he appropriate governmental agency(ies) and/or authority(ies) with jurisdiction over the implementation or siting of Gap Solutions will determine whether the Gap Solution or an alternative Gap Solution will be implemented to address the identified Reliability Need."³⁰

Once a Gap Solution is selected, which can include forestalling a generation unit retirement through an RSSA, the NYISO tariff provides further that the "[c]osts related to regulated non-transmission reliability projects will be recovered by Responsible Transmission Owners, Transmission

²⁹ PSL §§2(13), 65(1), 66(1), (2), (3) & (5).

³⁰ NYISO Open Access Transmission Tariff (OATT), Attachment Y, §31.2.10.4.

Owners and Other Developers in accordance with provisions of the New York Public Service Law, New York Public Authorities Law, or other applicable state law."³¹ Therefore, the tariff recognizes the Commission's authority to address a reliability need through directing the recovery of costs incurred in implementing a Gap Solution, such as the costs of retaining in service through an RSSA a generation facility that would otherwise be retired.

The FPA itself also preserves the Commission's authority over generation and reliability. Indeed, the FPA explicitly provides that States retain jurisdiction over "facilities used for the generation of electric energy" and the ability "to take action to ensure the safety, adequacy, and reliability of electric service within that State."³²

While it is true FERC has exclusive jurisdiction over rates for the wholesale transactions of energy,³³ an RSSA does not attempt to set wholesale rates. Instead, an RSSA is tied exclusively to the adequacy of reliability specifically reserved in the FPA to the States, in that payments are made in return for the obligation to remain in operation. As such, RSSA payments made for the purchase of such reliability attributes are no different than tax credits, grants, emissions reductions credits, renewable energy credits, or other methods of compensating generators for the attributes they provide that are outside the scope of FERC's wholesale markets, whether the costs are recovered through state-regulated distribution utility rates or other state-approved mechanisms.

Since the Commission, in carrying out its duty to address reliability issue under New York's Public Service Law is ensuring, through an RSSA, that electric service is safe and

³¹ NYISO OATT, Attachment Y, §31.5.1.6.

³² 16 U.S.C. §§824, 824d, 824e, 824o.

³³ 16 U.S.C. §824.

adequate, it is acting within the sphere accorded to it under the FPA. The federal preemption argument is therefore rejected.

The Commission orders:

1. Rochester Gas and Electric Corporation and R.E. Ginna Nuclear Power Plant LLC shall negotiate a Reliability Support Services Agreement in conformance with the discussion in the body of this Order, and make the filings regarding the Reliability Support Services Agreement described in the body of this Order by January 15, 2015.

2. Rochester Gas and Electric Corporation shall share the initial responses to its October 6, 2014 Request for Proposals with the Department of Public Service Staff (Staff) by November 25, 2014 and shall report its analysis of the short list of qualified bidders to Staff by December 23, 2014.

3. The Secretary in her sole discretion may extend the deadlines set forth in the Order, provided the request for an extension is in writing, includes a justification for the extension and is filed on at least one day's notice prior to the affected deadline.

4. This proceeding is continued.

By the Commission,

Kathleen H. Burgess
Digitally signed by Secretary
New York Public Service Commission

KATHLEEN H. BURGESS
Secretary

Cc EX. 105

Residential Apples to Apples Comparison Chart

Ohio Edison

To best utilize this offer comparison tool, it is suggested that you have your most current utility bill available for reference. Compare the supplier offers contained in the chart with the "Price to Compare" shown on your electric bill.

The offer prices below reflect that of the generation portion of your bill. Your distribution and transmission rates are determined through your local utility company.

Steps to Switching

four simple steps to choosing a supplier

1. Compare offers

Find your Price to Compare on your utility bill and use that number to compare to other offers listed on PUCO's *Apples to Apples* comparison chart. Since your Price to Compare is made up of several different factors it can vary from month-to-month. To get a better understanding of your average Price to Compare take a look at a few of your recent bills. After determining your Price to Compare, use our *Apples to Apples* chart to identify offers based on cost, contract length or other incentives.

2. Contact suppliers

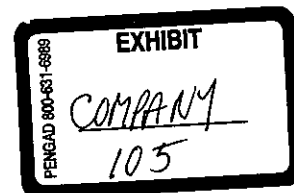
Contact the suppliers that you are most interested in and ask the questions provided below. To sign up simply call that supplier. The supplier will contact your local electric utility for you.

3. Read and understand the supply contract

Make sure you carefully read and understand all of the terms and conditions of your supply contract. The supplier should be able to answer any questions you have.

4. Receive confirmation

Your local electric utility will send you a letter confirming the supplier you have chosen. If the information is correct, you do not have to do anything. If the information is not correct, contact the utility and request that the switch be stopped. You have seven days from the postmark date of the letter to make any changes.





Energy Choice Ohio

powered by choice.

AEP Energy Inc
(855) 300-7191

Rate Type: Fixed	Term Length: 8 months	0% Renewable
\$0.0669 per kWh	Monthly Fee: \$0	Early Termination Fee: \$10

Additional Information: America's Energy Partner(SM) This price plan is through the December 2014 billing cycle. This offer is for residential customers of Ohio Edison only. Enroll in minutes at www.AEPenergy.com/fe10-web.
This is not a promotional offer.
This is not a introductory offer.

AEP Energy Inc
(855) 300-7191

Rate Type: Fixed	Term Length: 18 months	0% Renewable
\$0.0699 per kWh	Monthly Fee: \$0	Early Termination Fee: \$10

Additional Information: America's Energy Partner(SM) This offer is for residential customers of Ohio Edison only. Enroll in minutes at www.AEPenergy.com/fe18-web.
This is not a promotional offer.
This is not a introductory offer.

AEP Energy Inc
(855) 300-7191

Rate Type: Fixed	Term Length: 8 months	100% Renewable
\$0.0699 per kWh	Monthly Fee: \$0	Early Termination Fee: \$10

Additional Information: America's Energy Partner(SM) 100% Wind Product This price plan is through the December 2014 billing cycle. This offer is for residential customers of Ohio Edison only. Enroll in minutes at www.AEPenergy.com/fegreen-web.
This is not a promotional offer.
This is not a introductory offer.

AP Gas & Electric OH LLC
(877) 544-4857

Rate Type: Fixed	Term Length: 3 months	3% Renewable
\$0.0595 per kWh	Monthly Fee: \$0	Early Termination Fee: \$0

Additional Information: To Enroll call 888-797-4537 or via our website www.apge.com
This is a promotional offer. 3 Month Introductory Offer
This is a introductory offer.

Border Energy Electric Services Inc
(888) 901-8461

Rate Type: Fixed	Term Length: 10 months	3% Renewable
\$0.0595 per kWh	Monthly Fee: \$0	Early Termination Fee: \$75

Additional Information: Fixed Price of \$0.0595 per kWh Through December 31, 2014
This is not a promotional offer.
This is not a introductory offer.

Constellation NewEnergy Inc
(888) 898-4323

Rate Type: Fixed	Term Length: 12 months	0% Renewable
\$0.0689 per kWh	Monthly Fee: \$0	Early Termination Fee: \$25

Additional Information: None Provided
This is not a promotional offer.
This is not a introductory offer.

Direct Energy Services LLC
(888) 566-9988

Rate Type: Fixed	Term Length: 15 months	0% Renewable
\$0.0639 per kWh	Monthly Fee: \$0	Early Termination Fee: \$0

Additional Information: Eliminate market volatility and provide yourself price certainty with a fixed rate throughout the initial term of your contract. This rate excludes utility-related charges and taxes.
This is not a promotional offer.
This is not a introductory offer.

DP&L Energy
(800) 319-1356

Rate Type: Fixed	Term Length: 12 months	0% Renewable
\$0.0739 per kWh	Monthly Fee: \$0	Early Termination Fee: \$99

Additional Information: This offer is for residential customers of Ohio Edison, Toledo Edison and Cleveland Illuminating only
This is not a promotional offer.
This is not a introductory offer.



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DP&L Energy

(800) 319-1356

Rate Type: Fixed

Term Length: 38 months

0% Renewable

\$0.0745 per kWh

Monthly Fee: \$0

Early Termination Fee: \$299

Additional Information: This offer is for First Energy residential customers only and the term is through May 2017

This is not a promotional offer.

This is not a introductory offer.

DP&L Energy

(800) 319-1356

Rate Type: Fixed

Term Length: 36 months

0% Renewable

\$0.0755 per kWh

Monthly Fee: \$0

Early Termination Fee: \$199

Additional Information: This offer is for First Energy customers only

This is not a promotional offer.

This is not a introductory offer.

DP&L Energy

(800) 319-1356

Rate Type: Fixed

Term Length: 24 months

0% Renewable

\$0.0795 per kWh

Monthly Fee: \$0

Early Termination Fee: \$99

Additional Information: This offer is for residential customers of Ohio Edison, Cleveland Electric Illuminating & Toledo Edison

This is not a promotional offer.

This is not a introductory offer.

Duke Energy Retail Sales LLC

(855) 999-8817

Rate Type: Fixed

Term Length: 13 months

0% Renewable

\$0.0675 per kWh

Monthly Fee: \$0

Early Termination Fee: \$0

Additional Information: We Make the Right Choice Easy - \$0.0675/kWh through May 2015 - Residential Customers served by The Illuminating Company, Ohio Edison and Toledo Edison

This is not a promotional offer.

This is not a introductory offer.

FirstEnergy Solutions Corp

(866) 271-2265

Rate Type: Fixed

Term Length: 14 months

3% Renewable

\$0.0609 per kWh

Monthly Fee: \$0

Early Termination Fee: \$100

Additional Information: Short Term, fixed price offer is for FirstEnergy residential RS customers of Ohio Edison only. Through June 2015.

This is not a promotional offer.

This is not a introductory offer.

FirstEnergy Solutions Corp

(866) 271-2265

Rate Type: Fixed

Term Length: 50 months

3% Renewable

\$0.0669 per kWh

Monthly Fee: \$0

Early Termination Fee: \$100

Additional Information: PriceControl 4 year offer is for FirstEnergy residential RS customers of Ohio Edison. Through June 2018.

This is not a promotional offer.

This is not a introductory offer.

FTR Energy Services LLC

(877) 811-7023

Rate Type: Fixed

Term Length: 6 months

100% Renewable

\$0.0629 per kWh

Monthly Fee: \$0

Early Termination Fee: \$0

Additional Information: This is a Fixed 6-month Offer for Ohio Edison customers.

This is not a promotional offer.

This is not a introductory offer.

FTR Energy Services LLC

(877) 811-7023

Rate Type: Variable

Term Length: 0 month

100% Renewable

\$0.1099 per kWh

Monthly Fee: \$0

Early Termination Fee: \$0

Additional Information: This is the Standard Variable Offer for Ohio Edison customers.

This is not a promotional offer.

This is not a introductory offer.

FTR Energy Services LLC

(877) 811-7023

Rate Type: Variable

Term Length: 1 month

100% Renewable



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\$0.0989 per kWh

Monthly Fee: \$0

Early Termination Fee: \$0

Additional Information: This is a 1-month Introductory Price for Ohio Edison customers.
This is not a promotional offer.
This is a introductory offer.

IGS Energy

(800) 280-4474

Rate Type: Fixed

Term Length: 12 months

100% Renewable

\$0.0729 per kWh

Monthly Fee: \$0

Early Termination Fee: \$0

Additional Information: Fixed Rate Through 12 Billing Cycles
This is not a promotional offer.
This is not a introductory offer.

IGS Energy

(800) 280-4474

Rate Type: Fixed

Term Length: 12 months

0% Renewable

\$0.0749 per kWh

Monthly Fee: \$0

Early Termination Fee: \$0

Additional Information: 100% Green fixed rate through 12 billing cycle
This is not a promotional offer.
This is not a introductory offer.

Integrus Energy Services Inc

(800) 397-8072

Rate Type: Fixed

Term Length: 6 months

5% Renewable

\$0.0749 per kWh

Monthly Fee: \$0

Early Termination Fee: \$25

Additional Information: FE - Res - 6mo
This is not a promotional offer.
This is not a introductory offer.

Integrus Energy Services Inc

(800) 397-8072

Rate Type: Fixed

Term Length: 12 months

5% Renewable

\$0.0749 per kWh

Monthly Fee: \$0

Early Termination Fee: \$25

Additional Information: FE - Res - 12mo
This is not a promotional offer.
This is not a introductory offer.

Integrus Energy Services Inc

(800) 397-8072

Rate Type: Fixed

Term Length: 24 months

5% Renewable

\$0.0834 per kWh

Monthly Fee: \$0

Early Termination Fee: \$25

Additional Information: FE - Res - 24mo
This is not a promotional offer.
This is not a introductory offer.

Just Energy

(866) 587-8674

Rate Type: Fixed

Term Length: 12 months

0% Renewable

\$0.0819 per kWh

Monthly Fee: \$0

Early Termination Fee: \$50

Additional Information: 12 month Fixed Price Program
This is not a promotional offer.
This is not a introductory offer.

Just Energy

(866) 587-8674

Rate Type: Variable

Term Length: 1 month

0% Renewable

\$0.0584 per kWh

Monthly Fee: \$0

Early Termination Fee: \$0

Additional Information: Month to Month Variable Program with an Intro Period where the Intro Price will 5% below Utility for the first month, Thereafter a month to month Variable Rate
This is not a promotional offer.
This is a introductory offer.

Just Energy

(866) 587-8674

Rate Type: Variable

Term Length: 1 month

0% Renewable

\$0.0584 per kWh

Monthly Fee: \$0

Early Termination Fee: \$0



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Additional Information: Month to Month Variable Program with an Intro Period where the Intro Price will 5% below Utility for the first month. Thereafter a month to month Variable Rate
This is not a promotional offer.
This is an introductory offer.

KONA ENERGY

(855) 566-2669

Rate Type: Fixed	Term Length: 12 months	8% Renewable
\$0.0690 per kWh	Monthly Fee: \$0	Early Termination Fee: \$100

Additional Information: Kona Clear 12: Fixed-rate for 12 months. Get peace of mind. Hassle-free sign-up process. Kona Energy takes a refreshingly simple approach to electricity. Call 1-855-566-2669 or go to www.KonaEnergy.com
This is not a promotional offer.
This is not an introductory offer.

KONA ENERGY

(855) 566-2669

Rate Type: Fixed	Term Length: 18 months	8% Renewable
\$0.0700 per kWh	Monthly Fee: \$0	Early Termination Fee: \$100

Additional Information: Kona Clear 18: Fixed-rate for 18 months. Get peace of mind. Hassle-free sign-up process. Kona Energy takes a refreshingly simple approach to electricity. Call 1.855.KONA.NOW (1.855.566.2669) or go to www.konaenergy.com
This is not a promotional offer.
This is not an introductory offer.

KONA ENERGY

(855) 566-2669

Rate Type: Fixed	Term Length: 24 months	8% Renewable
\$0.0710 per kWh	Monthly Fee: \$0	Early Termination Fee: \$200

Additional Information: Kona Clear 24: Fixed-rate for 24 months. Get peace of mind. Hassle-free sign-up process. Kona Energy takes a refreshingly simple approach to electricity. Call 1.855.KONA.NOW (1.855.566.2669) or go to www.konaenergy.com
This is not a promotional offer.
This is not an introductory offer.

North American Power and Gas LLC

(888) 313-9086

Rate Type: Fixed	Term Length: 6 months	25% Renewable
\$0.0599 per kWh	Monthly Fee: \$0	Early Termination Fee: \$10

Additional Information: 6 month fixed rate.
This is not a promotional offer.
This is not an introductory offer.

North American Power and Gas LLC

(888) 313-9086

Rate Type: Fixed	Term Length: 6 months	100% Renewable
\$0.0794 per kWh	Monthly Fee: \$10	Early Termination Fee: \$10

Additional Information: 6 month fixed rate.
This is not a promotional offer.
This is not an introductory offer.

North American Power and Gas LLC

(888) 313-9086

Rate Type: Variable	Term Length: 0 month	25% Renewable
\$0.1149 per kWh	Monthly Fee: \$0	Early Termination Fee: \$0

Additional Information: For Existing Customers. Market-based general variable.
This is not a promotional offer.
This is not an introductory offer.

North American Power and Gas LLC

(888) 313-9086

Rate Type: Variable	Term Length: 0 month	100% Renewable
\$0.1154 per kWh	Monthly Fee: \$0	Early Termination Fee: \$0

Additional Information: For Existing Customers. Market-based general variable.
This is not a promotional offer.
This is not an introductory offer.

Verde Energy USA Ohio LLC

(800) 388-3862

Rate Type: Fixed	Term Length: 6 months	100% Renewable
\$0.0699 per kWh	Monthly Fee: \$0	Early Termination Fee: \$0



Energy Choice Ohio

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Additional Information: 100 % Renewable Fixed price of \$0.0699 per kWh for 6 billing cycles and variable thereafter. New enrollments receive a \$75 cash bonus, a 20% discount on energy saving products and free access to Verde Energy Savings Solutions where customers can monitor and analyze their energy use.
This is not a promotional offer.
This is not a introductory offer.

Verde Energy USA Ohio LLC

(800) 388-3862

Rate Type: Fixed

Term Length: 6 months

100% Renewable

\$0.0699 per kWh

Monthly Fee: \$0

Early Termination Fee: \$0

Additional Information: Fixed for 6 billing cycles, Month-to-month thereafter. New enrollments receive a \$75 cash bonus, a 20% discount on energy saving products and free access to Verde Energy Savings Solutions where customers can monitor and analyze their energy use.
This is not a promotional offer.
This is not a introductory offer.



Chart Definitions

Apples to Apples Charts: The PUCO's electric and natural gas offer comparison charts, the only comparisons in the state for which suppliers are required to provide accurate and up-to-date information about their latest offers.

ccf: Hundred cubic feet. Used to measure natural gas.

Customer Charge: Charge billed each month to recover a portion of the ongoing fixed costs of providing service to a consumer's home or business. See Fixed Delivery Charge.

Fixed Delivery Charge: Charge billed each month to recover a portion of the ongoing fixed costs of providing service to a consumer's home or business. See Customer Charge.

Electric Distribution Utility (EDU): The local electric distribution utility that delivers electricity to your home or business.

Supply Charge: The price of electricity or natural gas offered by a supplier.

Fixed Price: A fixed electricity or natural gas rate that will remain the same, for a set period of time.

Gas Cost Recovery (GCR) Charge: The actual cost of natural gas that a local distribution company (LDC) pays to purchase natural gas for your use. That cost is then passed through to you on a dollar-for-dollar basis with no mark-up or profit to the LDC. Only the actual costs of the natural gas are recovered through this process.

Generation Charge: The charge for producing electricity. If you purchase electricity from a supplier, your generation charge will depend on the contract between you and your supplier.

Kilowatt Hour (kwh): A 1,000-watt unit of energy for one hour. This is the standard measurement for the amount of electricity a customer uses.

Local Distribution Company (LDC): The local natural gas distribution utility that delivers natural gas to your home or business.

mcf: Thousand cubic feet. Used to measure natural gas.

Monthly Fee: A fixed monthly fee that a supplier may include in the terms and conditions of their contract that is in addition to a rate based on usage.

NYMEX: The New York Mercantile Exchange, a public market where natural gas and other commodities are sold and traded.

Price to Compare: The price for an electric supplier to beat in order for you to save money. It will be shown on residential customer's electric utility bill. You can use this amount to compare with prices offered by suppliers.

Renew. (Renewable) Content: The percentage of the contracted generation supply that is provided by a renewable energy source.

Renewable Energy: Electricity or natural gas that is made from environmentally friendly fuel resources, such as wind, water, biomass, biogas, waste heat or solar. Sometimes referred to as "green" energy.

Standard Choice Offer (SCO): Each year, Columbia Gas of Ohio, Dominion East Ohio and Vectren Energy Delivery of Ohio conduct auctions to secure natural gas supplies for customers who do not participate in the retail choice program. The auction establishes a SCO rate for choice-eligible customers. The SCO rate is based on the NYMEX month-end settlement price for natural gas, plus a retail price adjustment determined in the auctions. The retail price adjustment reflects the winning bidders' price to deliver natural gas from the production area to the utility's service area.

Standard Service Offer: The electric generation service a customer will receive from their local electric utility if they do not choose an electric supplier.

Transmission: The transporting of high-voltage electricity from generation at a power plant to local electric utilities.

Transmission Charge: Charge for transporting electricity from the generation plant to the local electric utility.

Transportation Cost: Cost related to the actual transportation of natural gas through the natural gas transmission pipeline to the LDC.

Variable Price: A variable rate can change, by the hour, day, month, etc., according to the terms and conditions of the supplier's contract.

CO. EX 106

Residential Apples to Apples Comparison Chart

Ohio Edison

To best utilize this offer comparison tool, it is suggested that you have your most current utility bill available for reference. Compare the supplier offers contained in the chart with the "Price to Compare" shown on your electric bill.

The offer prices below reflect that of the generation portion of your bill. Your distribution and transmission rates are determined through your local utility company.

Steps to Switching

four simple steps to choosing a supplier

1. Compare offers

Find your Price to Compare on your utility bill and use that number to compare to other offers listed on PUCO's *Apples to Apples* comparison chart. Since your Price to Compare is made up of several different factors it can vary from month-to-month. To get a better understanding of your average Price to Compare take a look at a few of your recent bills. After determining your Price to Compare, use our *Apples to Apples* chart to identify offers based on cost, contract length or other incentives.

2. Contact suppliers

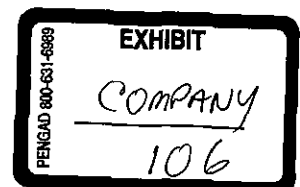
Contact the suppliers that you are most interested in and ask the questions provided below. To sign up simply call that supplier. The supplier will contact your local electric utility for you.

3. Read and understand the supply contract

Make sure you carefully read and understand all of the terms and conditions of your supply contract. The supplier should be able to answer any questions you have.

4. Receive confirmation

Your local electric utility will send you a letter confirming the supplier you have chosen. If the information is correct, you do not have to do anything. If the information is not correct, contact the utility and request that the switch be stopped. You have seven days from the postmark date of the letter to make any changes.





AEP Energy Inc
(855) 300-7191

Rate Type: Fixed	Term Length: 6 months	0% Renewable
\$0.0729 per kWh	Monthly Fee: \$0	Early Termination Fee: \$10

Additional Information: AMERICA'S ENERGY PARTNER(SM) This offer is available for residential customers of Ohio Edison, Cleveland Electric Illuminating & Toledo Edison Exclusive AEP Energy Website Offer For New Customers Only
This is not a promotional offer.
This is not a introductory offer.

AEP Energy Inc
(855) 300-7191

Rate Type: Fixed	Term Length: 36 months	0% Renewable
\$0.0773 per kWh	Monthly Fee: \$0	Early Termination Fee: \$10

Additional Information: America's Energy Partner(SM) This offer is available for residential customers of Ohio Edison, Cleveland Electric Illuminating & Toledo Edison
This is not a promotional offer.
This is not a introductory offer.

AEP Energy Inc
(855) 300-7191

Rate Type: Fixed	Term Length: 36 months	100% Renewable
\$0.0809 per kWh	Monthly Fee: \$0	Early Termination Fee: \$10

Additional Information: AMERICA'S ENERGY PARTNER(SM) 100% Wind Product This offer is available for residential customers of Ohio Edison, Cleveland Electric Illuminating & Toledo Edison
This is not a promotional offer.
This is not a introductory offer.

AP Gas & Electric OH LLC
(877) 544-4857

Rate Type: Fixed	Term Length: 12 months	4% Renewable
\$0.0849 per kWh	Monthly Fee: \$0	Early Termination Fee: \$25

Additional Information: None Provided
This is not a promotional offer.
This is not a introductory offer.

Censtar Energy Corp
(877) 529-6701

Rate Type: Fixed	Term Length: 24 months	0% Renewable
\$0.0849 per kWh	Monthly Fee: \$0	Early Termination Fee: \$25

Additional Information: 24 Month Fixed Price
This is not a promotional offer.
This is not a introductory offer.

Censtar Energy Corp
(877) 529-6701

Rate Type: Fixed	Term Length: 12 months	0% Renewable
\$0.0859 per kWh	Monthly Fee: \$0	Early Termination Fee: \$25

Additional Information: 12 Month Fixed Price
This is not a promotional offer.
This is not a introductory offer.

Constellation NewEnergy Inc
(888) 898-4323

Rate Type: Fixed	Term Length: 36 months	0% Renewable
\$0.0799 per kWh	Monthly Fee: \$0	Early Termination Fee: \$25

Additional Information: None Provided
This is not a promotional offer.
This is not a introductory offer.

Constellation NewEnergy Inc
(888) 898-4323

Rate Type: Fixed	Term Length: 12 months	0% Renewable
\$0.0859 per kWh	Monthly Fee: \$0	Early Termination Fee: \$25

Additional Information: None Provided
This is not a promotional offer.
This is not a introductory offer.



Energy Choice Ohio
powered by choice.

Published on Friday, March 20, 2015 at 6:00 AM
Ohio Edison

Direct Energy Services LLC
(877) 698-7551

Rate Type: Fixed	Term Length: 18 months	0% Renewable
\$0.0795 per kWh	Monthly Fee: \$0	Early Termination Fee: \$0

Additional Information: For new enrollment only. Take advantage of fixed pricing for 18 months and stop paying variable rates to your utility.
This is not a promotional offer.
This is not a introductory offer.

Direct Energy Services LLC
(877) 698-7551

Rate Type: Fixed	Term Length: 24 months	0% Renewable
\$0.0809 per kWh	Monthly Fee: \$0	Early Termination Fee: \$200

Additional Information: For new enrollment only. Receive a Nest Learning Thermostat and a fixed rate for 24 months.
This is not a promotional offer.
This is not a introductory offer.

Direct Energy Services LLC
(877) 698-7551

Rate Type: Fixed	Term Length: 6 months	0% Renewable
\$0.0815 per kWh	Monthly Fee: \$0	Early Termination Fee: \$99

Additional Information: For new enrollment only. Enjoy a fixed rate for 6 months and leave behind seasonal price changes from your utility company.
This is not a promotional offer.
This is not a introductory offer.

Direct Energy Services LLC
(877) 698-7551

Rate Type: Fixed	Term Length: 36 months	0% Renewable
\$0.0819 per kWh	Monthly Fee: \$0	Early Termination Fee: \$200

Additional Information: For new enrollment only. Choose a Comfort and Control Plan from Direct Energy and receive a Nest Learning Thermostat. Lock in your electricity rate for 36 months. Nest features help you use up to 20% less electricity.
This is not a promotional offer.
This is not a introductory offer.

Direct Energy Services LLC
(877) 698-7551

Rate Type: Fixed	Term Length: 12 months	0% Renewable
\$0.0825 per kWh	Monthly Fee: \$0	Early Termination Fee: \$99

Additional Information: For new enrollment only. Choose 1 year of great energy prices and defeat seasonal price shifts with a fixed-rate plan.
This is not a promotional offer.
This is not a introductory offer.

DP&L Energy
(800) 319-1356

Rate Type: Fixed	Term Length: 38 months	0% Renewable
\$0.0819 per kWh	Monthly Fee: \$0	Early Termination Fee: \$199

Additional Information: This offer is for First Energy/Ohio Edison residential customers only for term through May 2018.
This is not a promotional offer.
This is not a introductory offer.

DP&L Energy
(800) 319-1356

Rate Type: Fixed	Term Length: 12 months	0% Renewable
\$0.0829 per kWh	Monthly Fee: \$0	Early Termination Fee: \$99

Additional Information: This offer is for residential customers of Ohio Edison, Toledo Edison and Cleveland Illuminating only
This is not a promotional offer.
This is not a introductory offer.

DP&L Energy
(800) 319-1356

Rate Type: Fixed	Term Length: 26 months	0% Renewable
\$0.0849 per kWh	Monthly Fee: \$0	Early Termination Fee: \$199

Additional Information: This offer is for First Energy residential customers only and the term is through May 2017
This is not a promotional offer.
This is not a introductory offer.

DP&L Energy
(800) 319-1356

Rate Type: Fixed	Term Length: 24 months	0% Renewable
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\$0.0889 per kWh

Monthly Fee: \$0

Early Termination Fee: \$99

Additional Information: This offer is for residential customers of Ohio Edison, Cleveland Electric Illuminating & Toledo Edison
This is not a promotional offer.
This is not an introductory offer.

Duke Energy Retail Sales LLC
(855) 999-8817

Rate Type: Fixed

Term Length: 21 months

0% Renewable

\$0.0779 per kWh

Monthly Fee: \$0

Early Termination Fee: \$25

Additional Information: We Make the Right Choice Easy - \$0.0779/kWh through December 2016 - Residential Customers served by The Illuminating Company, Ohio Edison and Toledo Edison
This is not a promotional offer.
This is not an introductory offer.

Duke Energy Retail Sales LLC
(855) 999-8817

Rate Type: Fixed

Term Length: 9 months

0% Renewable

\$0.0779 per kWh

Monthly Fee: \$0

Early Termination Fee: \$0

Additional Information: We Make the Right Choice Easy - \$0.0779/kWh through December 2015 - Residential Customers served by The Illuminating Company, Ohio Edison and Toledo Edison
This is not a promotional offer.
This is not an introductory offer.

Hiko Energy LLC
(845) 406-9100

Rate Type: Variable

Term Length: 1 month

13% Renewable

\$0.1019 per kWh

Monthly Fee: \$0

Early Termination Fee: \$0

Additional Information: None Provided
This is a promotional offer. ONE FREE MONTH OF ENERGY SUPPLY after 12 consecutive months of service with HIKO - see welcome packet for details.
This is not an introductory offer.

IGS Energy
(800) 280-4474

Rate Type: Fixed

Term Length: 36 months

0% Renewable

\$0.0829 per kWh

Monthly Fee: \$0

Early Termination Fee: \$0

Additional Information: Fixed Rate of \$0.0829/kwh through 36 billing cycles, No early Termination Fee.
This is a promotional offer. Earn 5¢/gal in Fuel Rewards® Savings for every \$50 you spend with IGS Energy on your utility bill.
This is not an introductory offer.

IGS Energy
(800) 280-4474

Rate Type: Fixed

Term Length: 12 months

0% Renewable

\$0.0829 per kWh

Monthly Fee: \$0

Early Termination Fee: \$0

Additional Information: Fixed Rate Through 12 Billing Cycles
This is a promotional offer. Earn 5¢/gal in Fuel Rewards® Savings for every \$50 you spend with IGS Energy on your utility bill.
This is not an introductory offer.

IGS Energy
(800) 280-4474

Rate Type: Fixed

Term Length: 12 months

100% Renewable

\$0.0859 per kWh

Monthly Fee: \$0

Early Termination Fee: \$0

Additional Information: 100% Green fixed rate through 12 billing cycle
This is a promotional offer. Earn 5¢/gal in Fuel Rewards® Savings for every \$50 you spend with IGS Energy on your utility bill.
This is not an introductory offer.

Integrus Energy Services Inc
(800) 397-8072

Rate Type: Fixed

Term Length: 24 months

5% Renewable

\$0.0804 per kWh

Monthly Fee: \$0

Early Termination Fee: \$25

Additional Information: For residential customers of Ohio Edison
This is not a promotional offer.
This is not an introductory offer.

Integrus Energy Services Inc
(800) 397-8072

Rate Type: Fixed

Term Length: 6 months

5% Renewable

\$0.0869 per kWh

Monthly Fee: \$0

Early Termination Fee: \$25



Additional Information: For residential customers of Ohio Edison
This is not a promotional offer.
This is not a introductory offer.

Integrus Energy Services Inc
(800) 397-8072

Rate Type: Fixed	Term Length: 12 months	5% Renewable
\$0.0894 per kWh	Monthly Fee: \$0	Early Termination Fee: \$25

Additional Information: For residential customers of Ohio Edison
This is not a promotional offer.
This is not a introductory offer.

Just Energy
(866) 587-8674

Rate Type: Fixed	Term Length: 36 months	0% Renewable
\$0.0899 per kWh	Monthly Fee: \$0	Early Termination Fee: \$50

Additional Information: Fixed Price Program with an Intro Price which will be 5% below Utility for the first month.
This is not a promotional offer.
This is a introductory offer.

Just Energy
(866) 587-8674

Rate Type: Variable	Term Length: 1 month	0% Renewable
\$0.0636 per kWh	Monthly Fee: \$0	Early Termination Fee: \$0

Additional Information: Month to Month Variable Program with an Intro Period where the Intro Price will 5% below Utility for the first month. Thereafter a month to month Variable Rate
This is not a promotional offer.
This is a introductory offer.

Nordic Energy Services LLC
(630) 321-0888

Rate Type: Fixed	Term Length: 3 months	0% Renewable
\$0.0650 per kWh	Monthly Fee: \$0	Early Termination Fee: \$0

Additional Information: Fixed for three months then rate defaults to an hourly LMP index rate + \$.0175/kWh
This is not a promotional offer.
This is not a introductory offer.

North American Power and Gas LLC
(888) 313-9086

Rate Type: Fixed	Term Length: 6 months	25% Renewable
\$0.0849 per kWh	Monthly Fee: \$0	Early Termination Fee: \$10

Additional Information: 6 month fixed rate. 25% Renewable Energy Rate Available for New Customers Only.
This is not a promotional offer.
This is not a introductory offer.

North American Power and Gas LLC
(888) 313-9086

Rate Type: Fixed	Term Length: 12 months	25% Renewable
\$0.0899 per kWh	Monthly Fee: \$0	Early Termination Fee: \$10

Additional Information: 12 month fixed rate. 25% Renewable Energy. Rate Available for New Customers Only.
This is not a promotional offer.
This is not a introductory offer.

North American Power and Gas LLC
(888) 313-9086

Rate Type: Fixed	Term Length: 12 months	100% Renewable
\$0.1094 per kWh	Monthly Fee: \$0	Early Termination Fee: \$10

Additional Information: 12 month fixed rate-100% Renewable Energy. For new Customers
This is not a promotional offer.
This is not a introductory offer.

North American Power and Gas LLC
(888) 313-9086

Rate Type: Fixed	Term Length: 6 months	100% Renewable
\$0.1044 per kWh	Monthly Fee: \$10	Early Termination Fee: \$10

Additional Information: 6 month fixed rate. 100% Renewable Energy. Rate Available for New Customers Only.
This is not a promotional offer.
This is not a introductory offer.



North American Power and Gas LLC
(888) 313-9086

Rate Type: Variable	Term Length: 0 month	25% Renewable
\$0.1299 per kWh	Monthly Fee: \$0	Early Termination Fee: \$0

Additional Information: For Existing Customers. Market-based general variable. 25% Renewable Energy.
This is not a promotional offer.
This is not an introductory offer.

North American Power and Gas LLC
(888) 313-9086

Rate Type: Variable	Term Length: 0 month	100% Renewable
\$0.1494 per kWh	Monthly Fee: \$0	Early Termination Fee: \$0

Additional Information: For Existing Customers. Market-based general variable. 100% Renewable Energy
This is not a promotional offer.
This is not an introductory offer.

Plymouth Rock Energy LLC
(855) 327-6937

Rate Type: Fixed	Term Length: 24 months	0% Renewable
\$0.0860 per kWh	Monthly Fee: \$0	Early Termination Fee: \$0

Additional Information: Much like the weather, energy rates can be unpredictable. With Plymouth PriceLock you are completely free of the constantly fluctuating energy prices that consumers experience.
This is not a promotional offer.
This is not an introductory offer.

Plymouth Rock Energy LLC
(855) 327-6937

Rate Type: Fixed	Term Length: 18 months	0% Renewable
\$0.0904 per kWh	Monthly Fee: \$0	Early Termination Fee: \$0

Additional Information: Much like the weather, energy rates can be unpredictable. With Plymouth PriceLock you are completely free of the constantly fluctuating energy prices that consumers experience.
This is not a promotional offer.
This is not an introductory offer.

Plymouth Rock Energy LLC
(855) 327-6937

Rate Type: Fixed	Term Length: 6 months	0% Renewable
\$0.0911 per kWh	Monthly Fee: \$0	Early Termination Fee: \$0

Additional Information: Much like the weather, energy rates can be unpredictable. With Plymouth PriceLock you are completely free of the constantly fluctuating energy prices that consumers experience.
This is not a promotional offer.
This is not an introductory offer.

SANTANNA ENERGY SERVICES
(800) 764-4427

Rate Type: Fixed	Term Length: 6 months	3% Renewable
\$0.0840 per kWh	Monthly Fee: \$8	Early Termination Fee: \$0

Additional Information: Santanna's Competitive Fixed Price of \$0.0840 per kWh for initial term duration of 6 months and then a successive month-to-month term on Santanna's Competitive Market Price Program.
This is not a promotional offer.
This is not an introductory offer.

Source Power & Gas LLC
(888) 557-0065

Rate Type: Fixed	Term Length: 24 months	0% Renewable
\$0.0742 per kWh	Monthly Fee: \$0	Early Termination Fee: \$250

Additional Information: None Provided
This is not a promotional offer.
This is not an introductory offer.

Source Power & Gas LLC
(888) 557-0065

Rate Type: Fixed	Term Length: 12 months	0% Renewable
\$0.0798 per kWh	Monthly Fee: \$0	Early Termination Fee: \$150

Additional Information: None Provided
This is not a promotional offer.
This is not an introductory offer.



Star Energy Partners LLC
(855) 427-7827

Rate Type: Fixed	Term Length: 24 months	0% Renewable
\$0.0799 per kWh	Monthly Fee: \$0	Early Termination Fee: \$95

Additional Information: For residential customers of Ohio Edison - Ohio

This is not a promotional offer.

This is not an introductory offer.

Star Energy Partners LLC
(855) 427-7827

Rate Type: Fixed	Term Length: 24 months	25% Renewable
\$0.0839 per kWh	Monthly Fee: \$0	Early Termination Fee: \$95

Additional Information: 25% Wind For residential customers of Ohio Edison - Ohio

This is not a promotional offer.

This is not an introductory offer.

Star Energy Partners LLC
(855) 427-7827

Rate Type: Fixed	Term Length: 24 months	100% Renewable
\$0.0859 per kWh	Monthly Fee: \$0	Early Termination Fee: \$95

Additional Information: 100% Wind For residential customers of Ohio Edison - Ohio

This is not a promotional offer.

This is not an introductory offer.

Star Energy Partners LLC
(855) 427-7827

Rate Type: Fixed	Term Length: 24 months	25% Renewable
\$0.0869 per kWh	Monthly Fee: \$0	Early Termination Fee: \$95

Additional Information: 25% Green For residential customers of Ohio Edison - Ohio

This is not a promotional offer.

This is not an introductory offer.

Star Energy Partners LLC
(855) 427-7827

Rate Type: Fixed	Term Length: 12 months	0% Renewable
\$0.0919 per kWh	Monthly Fee: \$0	Early Termination Fee: \$50

Additional Information: For residential customers of Ohio Edison - Ohio

This is not a promotional offer.

This is not an introductory offer.

Star Energy Partners LLC
(855) 427-7827

Rate Type: Fixed	Term Length: 12 months	25% Renewable
\$0.0939 per kWh	Monthly Fee: \$0	Early Termination Fee: \$50

Additional Information: 25% Wind For residential customers of Ohio Edison - Ohio

This is not a promotional offer.

This is not an introductory offer.

Star Energy Partners LLC
(855) 427-7827

Rate Type: Fixed	Term Length: 12 months	100% Renewable
\$0.0949 per kWh	Monthly Fee: \$0	Early Termination Fee: \$50

Additional Information: 100% Wind For residential customers of Ohio Edison - Ohio

This is not a promotional offer.

This is not an introductory offer.

Star Energy Partners LLC
(855) 427-7827

Rate Type: Fixed	Term Length: 24 months	100% Renewable
\$0.0999 per kWh	Monthly Fee: \$0	Early Termination Fee: \$95

Additional Information: 100% Green For residential customers of Ohio Edison - Ohio

This is not a promotional offer.

This is not an introductory offer.

Titan Gas and Power
(888) 251-7006

Rate Type: Fixed	Term Length: 3 months	5% Renewable
\$0.0700 per kWh	Monthly Fee: \$0	Early Termination Fee: \$0



Additional Information: None Provided
This is not a promotional offer.
This is not an introductory offer.

Titan Gas and Power

(888) 251-7006

Rate Type: Fixed

Term Length: 12 months

5% Renewable

\$0.0730 per kWh

Monthly Fee: \$0

Early Termination Fee: \$10

Additional Information: None Provided
This is not a promotional offer.
This is not an introductory offer.

Titan Gas and Power

(888) 251-7006

Rate Type: Fixed

Term Length: 6 months

5% Renewable

\$0.0750 per kWh

Monthly Fee: \$0

Early Termination Fee: \$10

Additional Information: None Provided
This is not a promotional offer.
This is not an introductory offer.

Titan Gas and Power

(888) 251-7006

Rate Type: Variable

Term Length: 1 month

5% Renewable

\$0.0750 per kWh

Monthly Fee: \$0

Early Termination Fee: \$0

Additional Information: None Provided
This is not a promotional offer.
This is not an introductory offer.

Verde Energy USA Ohio LLC

(800) 388-3862

Rate Type: Fixed

Term Length: 6 months

100% Renewable

\$0.0999 per kWh

Monthly Fee: \$0

Early Termination Fee: \$0

Additional Information: Fixed for 6 billing cycles, Month-to-month thereafter. New enrollments receive a \$75 cash bonus, a 20% discount on energy saving products and free access to Verde Energy Savings Solutions where customers can monitor and analyze their energy use.

This is not a promotional offer.
This is not an introductory offer.

Viridian Energy PA, LLC

(866) 663-2508

Rate Type: Fixed

Term Length: 36 months

50% Renewable

\$0.0849 per kWh

Monthly Fee: \$0

Early Termination Fee: \$0

Additional Information: This is the current 50% green 3DOM Fixed rate that will be through 2/28/2018

This is not a promotional offer.
This is not an introductory offer.

Viridian Energy PA, LLC

(866) 663-2508

Rate Type: Fixed

Term Length: 36 months

100% Renewable

\$0.0949 per kWh

Monthly Fee: \$0

Early Termination Fee: \$0

Additional Information: This is the current 3DOM Fixed rate for 100% Green that will be through 2/38/2018

This is not a promotional offer.
This is not an introductory offer.

Viridian Energy PA, LLC

(866) 663-2508

Rate Type: Variable

Term Length: 1 month

100% Renewable

\$0.0900 per kWh

Monthly Fee: \$0

Early Termination Fee: \$0

Additional Information: This is the current 3DOM Term Free Index Rate for 50% Green. For more information about this rate please visit www.liveviridian.com/3DOM

This is not a promotional offer.
This is not an introductory offer.

Viridian Energy PA, LLC

(866) 663-2508

Rate Type: Variable

Term Length: 1 month

0% Renewable

\$0.1000 per kWh

Monthly Fee: \$0

Early Termination Fee: \$0



Additional Information: This is the current 100% green 3DOM Term Free Index Rate. For more information about this rate please visit www.liveviridian.com/3DOM
This is not a promotional offer.
This is not an introductory offer.

Viridian Energy PA, LLC
(866) 663-2508

Rate Type: Variable	Term Length: 6 months	50% Renewable
\$0.0642 per kWh	Monthly Fee: \$0	Early Termination Fee: \$0

Additional Information: This is the current 6-month offer of our 3DOM Flex rate plan. When signing up, you will have the option after 6 months to roll onto a 50% Green 30-month fixed rate of \$0.0799 or our 50% Green monthly published index rate
This is not a promotional offer.
This is an introductory offer.

Viridian Energy PA, LLC
(866) 663-2508

Rate Type: Variable	Term Length: 6 months	50% Renewable
\$0.0642 per kWh	Monthly Fee: \$0	Early Termination Fee: \$0

Additional Information: This is the current 6-month offer of our 3DOM Flex rate plan. When signing up, you will have the option after 6 months to roll onto a 100% Green 30-month fixed rate of \$0.0949 or our 100% Green monthly published index rate
This is not a promotional offer.
This is an introductory offer.

XOOM Energy Ohio LLC
(888) 997-8979

Rate Type: Fixed	Term Length: 24 months	0% Renewable
\$0.0849 per kWh	Monthly Fee: \$0	Early Termination Fee: \$200

Additional Information: SureLock 24
This is not a promotional offer.
This is not an introductory offer.

XOOM Energy Ohio LLC
(888) 997-8979

Rate Type: Fixed	Term Length: 12 months	0% Renewable
\$0.0879 per kWh	Monthly Fee: \$0	Early Termination Fee: \$100

Additional Information: SureLock 12
This is not a promotional offer.
This is not an introductory offer.

XOOM Energy Ohio LLC
(888) 997-8979

Rate Type: Fixed	Term Length: 12 months	50% Renewable
\$0.0899 per kWh	Monthly Fee: \$0	Early Termination Fee: \$100

Additional Information: SimpleClean 12
This is not a promotional offer.
This is not an introductory offer.

XOOM Energy Ohio LLC
(888) 997-8979

Rate Type: Variable	Term Length: 1 month	0% Renewable
\$0.0699 per kWh	Monthly Fee: \$0	Early Termination Fee: \$0

Additional Information: None Provided
This is a promotional offer. SimpleFlex
This is an introductory offer.

Chart Definitions

Applies to Apples Charts: The PUCO's electric and natural gas offer comparison charts, the only comparisons in the state for which suppliers are required to provide accurate and up-to-date information about their latest offers.

ccf: Hundred cubic feet. Used to measure natural gas.

Customer Charge: Charge billed each month to recover a portion of the ongoing fixed costs of providing service to a consumer's home or business. See Fixed Delivery Charge.

Fixed Delivery Charge: Charge billed each month to recover a portion of the ongoing fixed costs of providing service to a consumer's home or business. See Customer Charge.

Electric Distribution Utility (EDU): The local electric distribution utility that delivers electricity to your home or business.

Supply Charge: The price of electricity or natural gas offered by a supplier.

Fixed Price: A fixed electricity or natural gas rate that will remain the same, for a set period of time.

Gas Cost Recovery (GCR) Charge: The actual cost of natural gas that a local distribution company (LDC) pays to purchase natural gas for your use. That cost is then passed through to you on a dollar-for-dollar basis with no mark-up or profit to the LDC. Only the actual costs of the natural gas are recovered through this process.

Generation Charge: The charge for producing electricity. If you purchase electricity from a supplier, your generation charge will depend on the contract between you and your supplier.

Kilowatt Hour (kwh): A 1,000-watt unit of energy for one hour. This is the standard measurement for the amount of electricity a customer uses.

Local Distribution Company (LDC): The local natural gas distribution utility that delivers natural gas to your home or business.

mcf: Thousand cubic feet. Used to measure natural gas.

Monthly Fee: A fixed monthly fee that a supplier may include in the terms and conditions of their contract that is in addition to a rate based on usage.

NYMEX: The New York Mercantile Exchange, a public market where natural gas and other commodities are sold and traded.

Price to Compare: The price for an electric supplier to beat in order for you to save money. It will be shown on residential customer's electric utility bill. You can use this amount to compare with prices offered by suppliers.

Renew. (Renewable) Content: The percentage of the contracted generation supply that is provided by a renewable energy source.

Renewable Energy: Electricity or natural gas that is made from environmentally friendly fuel resources, such as wind, water, biomass, biogas, waste heat or solar. Sometimes referred to as "green" energy.

Standard Choice Offer (SCO): Each year, Columbia Gas of Ohio, Dominion East Ohio and Vectren Energy Delivery of Ohio conduct auctions to secure natural gas supplies for customers who do not participate in the retail choice program. The auction establishes a SCO rate for choice-eligible customers. The SCO rate is based on the NYMEX month-end settlement price for natural gas, plus a retail price adjustment determined in the auctions. The retail price adjustment reflects the winning bidders' price to deliver natural gas from the production area to the utility's service area.

Standard Service Offer: The electric generation service a customer will receive from their local electric utility if they do not choose an electric supplier.

Transmission: The transporting of high-voltage electricity from generation at a power plant to local electric utilities.

Transmission Charge: Charge for transporting electricity from the generation plant to the local electric utility.

Transportation Cost: Cost related to the actual transportation of natural gas through the natural gas transmission pipeline to the LDC.

Variable Price: A variable rate can change, by the hour, day, month, etc., according to the terms and conditions of the supplier's contract.

CUSTOMER GUIDE TO PJM BILLING

- Billing Line Items include PJM Open Access Transmission Tariff (OATT) references, PJM Operating Agreement (OpAgr) references, and PJM Manual references.
- Reports are available for viewing, printing, and downloading from PJM's Market Settlement Reporting System (MSRS).

Billing Line Item	Description	Reports
Network Integration Transmission Service (OATT Section 34, Attachments H-1 through H-17, Attachment H-A, and TOA Section 7.8 Manual 27, Section 6)	Network customers pay daily demand charges to PJM transmission owners using the applicable zonal or non-zone Network Integration Transmission Service rates. All network customers in the AP zone receive rebates to hold them harmless from the network rate conversion upon PJM integration. For transmission owners (except those in ATSI, PPL, ComEd, Dayton, Duke, and Duquesne zones), the charges for their own transmission facilities are not actually paid (i.e., exempted with an equal amount credits) and are shown only to identify their cost responsibility as ordered by FERC. Charges: Daily demand charges calculated as network customers' daily network service peak load contribution times 1/365th of the applicable zonal rate(s) for the zone(s) in which the network load is located. Monthly negative offset charges are rebated to AP zone network customers based on the applicable rates in PJM tariff Attachment H-11, section 4. Non-zone network service peak load contributions are coincident with the PJM Region peak. Credits: PJM zonal network transmission service revenues allocated to the applicable zone's transmission owners on a transmission revenue requirement basis. PJM non-zone network revenues allocated to transmission owners based on transmission revenue requirement ratio shares, with the ComEd, AEP, and Dominion shares further allocated to their respective zonal network customers based on demand charge ratios.	<i>NITS Charge Summary</i> <i>NITS Credit Summary</i> <i>NITS Offset Charge Summary</i> <i>Non-Zone NITS Credit Summary</i>
Firm Point-to-Point Transmission Service (OATT Section 13.7, Schedule 7, and TOA Section 7.8 Manual 27, Section 6)	Firm point-to-point transmission customers pay demand charges for reserved capacity at the applicable tariff rates based on the term of the reservations. There is no charge for reserved capacity with a MISO point of delivery. Charges: Monthly demand charges for daily, weekly, monthly, and yearly delivery calculated based on the transmission customer's reserved capacity times the applicable tariff rate. The total demand charge in any week, pursuant to a reservation for daily delivery, shall not exceed the weekly delivery rate times the highest amount of reserved capacity in any day during such week. Credits: Total firm transmission service revenues allocated to PJM transmission owners based on transmission revenue requirement ratio shares, with the ComEd, AEP, and Dominion shares further allocated to their respective zonal network customers based on demand charge ratios.	<i>Firm PTP Charges</i> <i>Firm PTP Credit Summary</i>
Non-Firm Point-to-Point Transmission Service (OATT Sections 14.5 & 27A, Schedule 8 Manual 27, Section 6)	Non-firm point-to-point transmission customers pay demand charges for reserved capacity at the discounted rate. There is no charge for reserved capacity with a MISO point of delivery. Charges: Monthly demand charges for hourly, daily, weekly, and monthly delivery calculated based on the transmission customer's reserved capacity (in MWh) times the discounted rate of \$0.67/MWh. Rebates are provided for transaction MWh curtailed by PJM and for transmission congestion charges. Credits: Total non-firm transmission service revenues allocated to PJM network and firm point-to-point transmission customers in proportion to their monthly demand charges.	<i>Non-Firm PTP Charges</i> <i>Non-Firm PTP Credit Summary</i>
Transmission Enhancement (OATT Schedule 12)	All network customers and merchant transmission owners pay transmission owners for required transmission enhancement projects in accordance with the zonal cost responsibility allocations in the appendix to Schedule 12. All transmission projects collecting these payments are on PJM's website under Transmission Services/Formula Rates. Charges: All network customers serving load in a responsible zone pay for that zone's applicable projects' revenue requirements in proportion to their network service peak load share in that zone, and responsible merchant transmission owners also pay their share of applicable revenue requirements. Note that several EDCs bear these charges for the default suppliers in their territory. Credits: Total revenues allocated to the applicable transmission enhancement project owners, or the applicable transmission zone network customers for zonal TOs that include these project costs in their network rates.	<i>Transmission Enhancement Charge Summary</i> <i>Transmission Enhancement Credit Summary</i>



Billing Line Item	Description	Reports
Spot Market Energy (OpAgt Schedules 1-3.2.1 & 3.3.1 and OATT Schedule 4 Manual 28, Section 3)	Day-ahead energy market net hourly PJM Interchange MWh are calculated for cleared day-ahead generation and increment offers, demand, decrement, and load response bids, and day-ahead energy transactions. Real-time energy market net hourly PJM Interchange MWh are calculated for real-time energy transactions, load (without losses), generation, and metered tie flows, as applicable. Day-ahead Charges: Net day-ahead PJM Interchange is charged hourly at the PJM-wide day-ahead system energy price. Charges are positive for net buyers and negative for net sellers of day-ahead spot market energy. Balancing Charges: Net real-time deviations from day-ahead PJM Interchange is charged hourly at the PJM-wide real-time system energy price. Charges may be positive or negative depending on the direction of the real-time deviation from day-ahead interchange. Reconciliation Charges: Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the PJM-wide real-time system energy price on a two-month billing lag.	DA Daily Energy Transactions RT Daily Energy Transactions for customer review and verification Spot Market Energy Charge Summary Energy & Inadvertent Load Recon Charge Summary Transmission Congestion Charge Summary
Transmission Congestion (OpAgt Schedules 1-3.2.4, 3.4.1, & 5.1-5.2 Manual 28, Section 8)	The increased energy costs due to redispatch during hours when the PJM transmission system is constrained are assessed to market participants based on the congestion price component of LMPs, and the revenues collected are allocated to FTR holders. Day-ahead Charges: A day-ahead Net Congestion Bill is calculated hourly as the sum of day-ahead withdrawal charges (i.e., all cleared day-ahead demand/decrement/load response bids and sale transactions priced at applicable buses' day-ahead congestion prices) minus the sum of day-ahead injection credits (i.e., all cleared day-ahead generation/increment offers and purchase transactions priced at applicable buses' day-ahead congestion prices). Hourly day-ahead implicit congestion charges equal the day-ahead Net Congestion Bill. Hourly explicit congestion charges for day-ahead energy transactions equal the scheduled MWh times the difference between day-ahead sink and source congestion prices and are assessed to the buyer (or point-to-point transmission customer, if applicable). Balancing Charges: A balancing Net Congestion Bill is calculated hourly as the sum of balancing withdrawal charges (i.e., all deviations between demand/decrement/load response bids and sale transactions cleared day-ahead and real-time load, without losses, and sale transactions priced at the applicable buses' real-time congestion prices) minus the sum of balancing injection credits (i.e., all deviations between generation/increment offers and purchase transactions cleared day-ahead and real-time generation and purchase transactions priced at the applicable buses' real-time congestion prices). Hourly balancing implicit congestion charges equal the balancing Net Congestion Bill. Hourly explicit congestion charges for balancing energy transactions equal any real-time deviations from the transaction MWh cleared day-ahead times the difference between real-time sink and source congestion prices and assessed to the buyer (or point-to-point transmission customer, if applicable). Credits: Total congestion revenues allocated as hourly credits based on FTR target allocations (FTR MW times the difference between day-ahead FTR sink and source congestion prices). Excess hourly congestion credits (including NYISO Unscheduled Transmission Service revenues, net MISO and NYISO congestion adjustment, inadvertent interchange congestion contribution, and ARR and FTR Auction net revenues remaining after initial distribution to any ARR deficiencies) are used to proportionately eliminate target deficiencies in other hours of the month. Any additional excess monthly congestion revenues are allocated to previous deficient months of the planning period with any excess at the end of the planning period allocated proportionately to FTR holders with net positive FTR target allocations for that planning period. Any deficiencies remaining at the end of a planning period are eliminated by reallocating all planning period FTR congestion revenues among FTR holders to yield a uniform ratio of deficiency. Reconciliation Charges: Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the applicable source/sink congestion price on a two-month billing lag.	Explicit Congestion Charges Implicit Congestion and Loss Charge Details FTR Target Credits Hourly Transmission Congestion Credits Congestion and Loss Load Recon Charges Congestion Uplift Charge Summary Network ARR Target Credit Summary Cross-Monthly Congestion Credit Summary

Planning Period Congestion Uplift (OpAgr Schedules 5.2.5 & 5.2.6 Manual 28, Section 8)	For planning years in which the sum of actual Transmission Congestion credits paid to FTR holders during the planning year was less than the sum of their FTR Targets, Planning Period Congestion Uplift credits are awarded to the FTR holders at the end of the planning year (May) to completely fulfill those remaining FTR Target deficiencies. Planning Period Congestion Uplift credits and Planning Period Congestion Uplift charges can only occur at the end of the Annual Planning Period (which runs from June 1st through May 31st), so they will only apply to May monthly billing statements. The "Planning Period Congestion Uplift credit" is a "make-whole" congestion credit to FTR holders to satisfy any previously unfulfilled FTR Target Credits that remain at the end of the planning year. A summary of FTR Targets and all applicable Congestion Credits broken down by month can be viewed in the "Cross-Monthly Congestion Credit Summary" report in MSRS. Select the "All Billed" option for the period from 6/1/12 through 5/31/13 to see the complete set of details. The "Planning Period Congestion Uplift charge" is the participant's share of the allocated costs of providing the Uplift credits. Charges are allocated to FTR holders in proportion to their net positive total FTR Target Credits for the planning year. Details of this charge allocation can be viewed in the "Congestion Uplift Charge Summary" report in MSRS. The calculation for the Uplift charge is: (positive FTR Target credit / Total PJM Positive FTR Target Credit) * PJM Total FTR and ARR Uplift Credit. The uplift process is also outlined in Manual 28, sections 8.1 and 8.4.4	Congestion Uplift Charge Summary Cross-Monthly Congestion Credit Summary
Planning Period Excess Congestion (OpAgr Schedule 5.2.6 Manual 28, Section 8.4.4)	For planning years in which the sum of total PJM congestion revenues collected during the planning year was greater than the sum of FTR holders' total net FTR Targets, Planning Period Excess Congestion credits are awarded to the FTR holders at the end of the planning year (May) to distribute those remaining excess congestion revenues. Planning Period Excess Congestion credits can only occur at the end of the Annual Planning Period (which runs from June 1st through May 31st), so they will only apply to May monthly billing statements. Planning Period Excess Congestion credits are allocated to FTR holders in proportion to their net positive total FTR Target Credits for the planning year.	Cross-Monthly Congestion Credit Summary

Billing Line Item	Description	Reports
Transmission Losses (OpAgr Schedules 1-3.2.5, 3.4.2, & 5.4-5.5 Manual 28, Section 9)	The increased costs of energy due to transmission losses represented in the PJM network model are assessed to market participants based on the loss component of LMPs, and the revenues collected are allocated to market participants' serving load and delivering PJM exports (that pay for PJM transmission service). Day-ahead Charges: An hourly day-ahead Net Loss Bill is calculated as day-ahead withdrawal charges (i.e., all cleared day-ahead demand/decrement/load response bids and sale transactions priced at applicable buses' day-ahead loss prices) minus day-ahead injection credits (i.e., all cleared day-ahead generation/increment offers and purchase transactions priced at applicable buses' day-ahead loss prices). Hourly day-ahead implicit loss charges equal the day-ahead Net Loss Bill. Hourly explicit loss charges for day-ahead energy transactions equal the scheduled MWh times the difference between day-ahead sink and source loss prices and assessed to the buyer (or point-to-point transmission customer, if applicable). Balancing Charges: An hourly balancing Net Loss Bill is calculated as balancing withdrawal charges (i.e., all deviations between demand/decrement/load response bids and sale transactions cleared day-ahead and real-time load, without losses, and sale transactions priced at the applicable buses' real-time loss prices) minus balancing injection credits (i.e., all deviations between generation/increment offers and purchase transactions cleared day-ahead and real-time generation and purchase transactions priced at the applicable buses' real-time loss prices). Hourly balancing implicit loss charges equal the balancing Net Loss Bill. Hourly explicit loss charges for balancing energy transactions equal any real-time deviations from day-ahead transaction MWh times the difference between real-time sink and source loss prices and assessed to the buyer (or point-to-point transmission customer, if applicable). Credits: Total hourly loss revenues, both day-ahead and balancing (including loss contribution of inadvertent interchange) allocated as hourly credits based on ratio shares of real-time load (without losses) plus exports that pay for transmission service (with non-firm exports receiving 31% of their allocation). Reconciliation Charges: Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the applicable source/sink loss price on a two-month billing lag. Reconciliation Credits: Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using a \$/MWh billing determinant calculated as the total loss credits divided by the total MWh of PJM real-time load plus exports (that pay for transmission service, with non-firm exports receiving 31% of their allocation) on a two-month billing lag.	Transmission Loss Charge Summary Explicit Loss Charges Implicit Congestion and Loss Charge Details Transmission Loss Credit Summary Congestion and Loss Load Recon Charges Transmission Loss Load Recon Credit Summary
Inadvertent Interchange (OpAgr Schedule 1-3.7 Manual 28, Section 18)	Charges: PJM hourly total inadvertent interchange charges (+/-) priced at the load weighted-average PJM real-time LMP and allocated based on real-time load ratio shares. Reconciliation Charges: Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the PJM-wide real-time system energy price on a two-month billing lag.	Inadvertent Interchange Charge Summary Energy & Inadvertent Load Recon Charge Summary
Load Response (OpAgr, just prior to Schedule 2 Manual 28, Section 11)	Credits: Day-ahead and real-time economic and real-time pre-emergency and emergency load response credits are provided to CSPs equal to the reduced MWh times LMP (minus retail rate, as applicable). Charges: For day-ahead and real-time economic load response, the CSP's LSE is charged the difference between LMP and the retail rate, as applicable, times the MWh reduction. For pre-emergency and emergency load response, all balancing energy market participants are allocated charges using the same method as for PJM emergency energy purchases.	Load Response Summary Econ Load Response Zonal Charge Allocations Emergency Load Response Allocation Summary Emergency Load Response Allocation Credits
Meter Error Correction (OpAgr Schedule 1-3.6 Manual 28, Section 12)	Charges: Monthly charges (+/-) to PJM fully-metered EDCs and generators for corrections to metered energy values, with PJM Mid-Atlantic 500kV corrections allocated based on real-time load ratio shares, using the applicable generator or PJM load weighted-average real-time LMP for the month. Meter correction charges for any external PJM tie-line corrections are allocated to all LSEs based on real-time load (without losses) ratio shares. Effective February 2010, EDCs may elect to have their charges (+/-) directly allocated by PJM to LSEs in their zone based on load ratio shares if all LSEs in the EDC territory concur.	Meter Correction Charge Summary Meter Correction Allocation Charge Summary
Emergency Energy (OpAgr Schedules 1-3.2.6, 3.3.4, 3.5.1, & 4.3 Manual 28, Section 10)	PJM emergency energy transactions (made on behalf of market participants) are priced at 150% of LMP at the appropriate PJM interface in accordance with the PJM agreements with adjacent control areas. Charges: Hourly net costs of emergency energy purchased by PJM are allocated to real-time deviations from day-ahead net interchange that create a shorter real-time position, except for purchases for external control areas' MinGen Emergencies where costs are allocated to deviations that create a longer position. Credits: Hourly net revenues from emergency energy sold by PJM are allocated to real-time deviations from day-ahead net interchange that create a shorter real-time position and to any curtailed exports, except for PJM MinGen Emergency sales where revenues are allocated to deviations that create a longer position.	Emergency Energy Charge and Credit Allocation Summary Emergency Energy Transactions

Billing Line Item	Description	Reports
PJM Scheduling, System Control & Dispatch Service (OATT Schedules 1 and 9-1 through 9-6 Manual 27, Section 2)	Charges: PJM's monthly operating expenses for the following service categories are allocated to PJM members on an unbilled basis. Charge refunds are provided in the year following any year in which there is an over collection of PJM's monthly operating expenses. Control Area Administration – 2015 rate of \$0.1692/MWh (with \$0.0 refund rate for Apr-Jun) charged to transmission customers based on their usage of the PJM transmission system. Monthly transmission use (in MWh) includes network customers' real-time load and point-to-point customers' real-time energy use. Financial Transmission Rights Administration – 2015 rate of \$0.0025/FTR MWh (with \$0.0/FTR MWh refund for Apr-Jun) charged to FTR holders based on FTR MW and hours each FTR is in effect (regardless of congested hours and dollar value of FTR). 2015 rate of \$0.0017/bid-hour (with \$0.0 refund rate for Apr-Jun) charged to FTR Auction participants based on the number of hours associated with each FTR obligation bid submitted in an FTR Auction (this rate is multiplied by 5 for FTR options). Market Support – 2015 rate of \$0.0373/MWh (with \$0.0 refund rate for Apr-Jun) charged to transmission customers based on their network load and exports, to providers of generation and imports, and to day-ahead energy market participants based on their accepted increment offers, decrement bids, and up-to congestion bids. 2015 rate of \$0.0558 (with \$0.0 refund rate for Apr-Jun) is charged for each energy bid/offer segment price/quantity pair submitted, including those submitted during the rebidding period. Regulation and Frequency Response Administration – 2015 rate of \$0.2271/Regulation MWh (with \$0.0 refund rate for Apr-Jun) charged to customers based on regulation obligation and regulation provided. Capacity Resource and Obligation Management – 2015 rate of \$0.0864/MW-day (with \$0.0 refund rate for Apr-Jun) charged to LSEs based on their daily unforced capacity obligations and to capacity resource owners based on their daily unforced capacity (including FRRs). Costs of Advanced Second Control Center (AC²) – Starting June 2008, monthly accrued actual costs related to AC² are collected across all users of Schedule 9-1 through 9-5 based on usage shares with the costs allocated to the applicable schedules in accordance with the PJM tariff. Market Support Offset – Apr-Jun 2015 rate of \$0.0044/MWh refunded to transmission customers based on their network load and exports, to providers of generation and imports, and to day-ahead energy market participants based on their accepted increment offers, decrement bids, and up-to congestion bids to reflect the reimbursement made to offset the PJM Settlement, Inc. charges. Reconciliation Charges: Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using a \$/MWh billing determinant calculated as the Control Area Administration Service Rate plus the Market Support Service Rate for transmission customers on a two-month billing lag. Charge refund amounts are also reconciled using the applicable refund rate billing determinants. Schedule 9-6 AC² charges are also reconciled using the applicable billing determinants.	Schedule 9 and 10 Charge Details Advanced Second Control Center Charge Details Schedule 9 & 10 Load Reconciliation Charge Summary
PJM Settlement, Inc. (OATT Schedule 9-PJM Settlement Manual 27, Section 2.2)	Charges: Apr-Jun 2015 rate of \$0.0044/MWh charged to transmission customers based on their network load and exports, to providers of generation and imports, and to day-ahead energy market participants based on their accepted increment offers, decrement bids, and up-to congestion bids. This charge funds the administration of PJM Settlement, Inc. who acts as the contractual counterparty to PJM market transactions and performs the billing collection and credit management services for PJM members.	Schedule 9 and 10 Charge Details
MMU Funding (OATT Schedule 9-MMU Manual 27, Section 2)	Charges: 2015 rate of \$0.00390/MWh charged to transmission customers based on their network load and exports, to providers of generation and imports, and to day-ahead energy market participants based on their accepted increment offers, decrement bids, and up-to congestion bids. 2015 rate of \$0.00384 is charged for each energy bid/offer segment price/quantity pair submitted, including those submitted during the rebidding period. Reconciliation Charges: Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the MMU rate on a two-month billing lag.	Schedule 9 and 10 Charge Details Schedule 9 & 10 Load Reconciliation Charge Summary
FERC Annual Recovery (OATT Schedule 9-FERC Manual 27, Section 2)	Charges: 2015 rate of \$0.0670/MWh charged to transmission customers based on their usage of the PJM transmission system. Monthly transmission use includes network customers' real-time load and point-to-point transmission customers' real-time energy transactions. Reconciliation Charges: Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the FERC rate on a two-month billing lag.	Schedule 9 and 10 Charge Details Schedule 9 & 10 Load Reconciliation Charge Summary

Organization of PJM States, Inc. (OPSI) Funding (OATT Schedule 9-OPSI Manual 27, Section 2)	Charges: 2015 rate of \$0.00069/MWh charged to transmission customers based on their usage of the PJM transmission system. Monthly transmission use includes network customers' real-time load and point-to-point transmission customers' real-time energy transactions. Reconciliation Charges: Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the OPSI rate on a two-month billing lag.	Schedule 9 and 10 Charge Details Schedule 9 & 10 Load Recon Charge Summary
North American Electric Reliability Corp. (NERC) (OATT Schedule 10- NERC Manual 27, Section 2)	Charges: 2015 rate of \$0.0118/MWh charged to transmission customers based on their energy delivered to load in the PJM Region, excluding load in the Dominion and East Kentucky Power Cooperative zones. Each calendar year, any over or under collection of NERC's actual costs are trued up in that year's December billing cycle. Reconciliation Charges: Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the NERC rate on a two-month billing lag.	Schedule 9 and 10 Charge Details Schedule 9 & 10 Load Recon Charge Summary

Billing Line Item	Description	Reports
Reliability First Corp. (RFC) (OATT Schedule 10-RFC Manual 27, Section 2)	Charges: 2015 rate of \$0.0192/MWh charged to transmission customers based on their energy delivered to load in the PJM Region, excluding load in the Dominion and East Kentucky Power Cooperative zones. Each calendar year, any over or under collection of RFC's actual costs are true up in that year's December billing cycle. Reconciliation Charges: Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the RFC rate on a two-month billing lag.	Schedule 9 and 10 Charge Details Schedule 9 & 10 Load Recon Charge Summary
Transmission Owner Scheduling, System Control and Dispatch Service (OATT Schedule 1A Manual 27, Section 2)	All Transmission Customers purchase this from PJM to schedule energy through, out, within, or into PJM. Charges: Monthly charges for the operation of the PJM transmission owners' control centers are calculated for transmission customers based on their monthly usage of the PJM transmission system. Point-to-Point Transmission Customers pay a pool-wide rate of \$0.0912/MWh based on their energy deliveries including losses and network customers pay applicable zonal rates provided in Schedule 1A of the Tariff based on the real-time MWh of monthly load they serve. Credits: The charges collected from network customers for each zone are provided to the applicable transmission owner, and the non-zone revenues (e.g., received from point-to-point customers) are allocated to PJM transmission owners based on fixed percentage shares provided in Schedule 1A of the Tariff. Reconciliation Charges: Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using zonal \$/MWh billing determinants equal to the applicable zonal Schedule 1A rates on a two-month billing lag.	Sched 1A Charge Summary Sched 1A Credit Summary Sched 1A Load Recon Charge Summary
Reactive Supply and Voltage Control from Generation and Other Sources Service (OATT Schedule 2 Manual 27, Section 3)	All Transmission Customers purchase this from PJM to maintain acceptable transmission voltages. Credits: Monthly credits provided to generation and transmission owners with FERC-approved reactive revenue requirements. Charges: Monthly pool-wide reactive revenue requirements allocated as charges to point-to-point customers (and to network customers in transmission zones with no reactive revenue requirements) based on their monthly peak usage of the PJM transmission system. Monthly peak usage equals the total hourly amounts of transmission capacity reserved, and not curtailed by PJM, divided by 24. The remaining reactive revenue requirements for each transmission zone not recovered from point-to-point customers are allocated to the network customers serving load in that zone based on their monthly network service peak load contributions.	Reactive Charge Summary
Regulation and Frequency Response Service (OpAgr Schedules 1-3.2.2, 3.2.2A, 3.3.2, & 3.3.2A and OATT Schedule 3 Manual 28, Section 4)	PJM conducts a regulation market to continuously balance generation resources with PJM load and to maintain interconnection frequency within acceptable limits. Credits: Generators and demand resources receive hourly credits for pool- and self-scheduled regulation (with consideration of the resource's performance) priced at the regulation market capability clearing price. Generators and demand resources receive hourly credits for pool- and self-scheduled regulation (with consideration of the resource's performance and the ratio between the requested mileage for the regulation dispatch signal assigned to the resource and the mileage for the traditional regulation signal (mileage ratio)) priced at the regulation market performance clearing prices. Additional credits provided to pool-scheduled regulating resources for any unrecovered portion of regulation offer plus opportunity cost. Charges: PJM LSEs have an hourly regulation obligation equal to their real-time load (without losses) ratio share of regulation supplied excluding mileage (adjusted for any bilateral regulation transactions). PJM LSEs also have an hourly regulation mileage obligation equal to their adjusted obligation ratio share of the mileage component of the regulation supplied. Hourly charges calculated as adjusted obligations times the regulation market capability and performance clearing prices and the regulation mileage obligation times the regulation market performance clearing price. Additional charges are assessed for any unrecovered cost payments that PJM provides to regulation suppliers and allocated to regulation market purchasers based on their share of any portion of their adjusted obligation in excess of their self-scheduled regulation. Reconciliation Charges: Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using a \$/MWh billing determinant calculated as the total regulation market charges divided by the total MWh of PJM real-time load served on a two-month billing lag.	Regulation Summary Regulation Credits Load Response Regulation Credits Reg Load Recon Charge Summary

Billing Line Item	Description	Reports
Synchronized Reserve (OpAgr Schedules 1-3.2.3A & 3.3.5 and OATT Schedule 5 Manual 28, Section 6)	PJM conducts synchronized reserve markets to ensure the capability of synchronized generation and demand resources that can be converted fully into energy within ten minutes. Credits: Generators that increase output and demand resources that decrease consumption in response to a synchronized reserve event when non-synchronized reserve clearing prices are zero receive Tier 1 credits equal to response MWh times synchronized reserve energy premium less its hourly LMP. During hours when the non-synchronized reserve clearing price is non-zero resources receive Tier 1 credits equal to the lesser of the response MWh or the Tier 1 estimate times the applicable reserve zone's Synchronized Reserve Market Clearing Price. Resources receive Tier 2 hourly credits for pool- and self-scheduled synchronized reserve resources for any portion of synchronized reserve offer plus opportunity provided to pool-scheduled synchronized reserve resources via Synchronized Reserve Market Clearing Price revenues. Charges: PJM LSEs that are not part of an agreement to share reserves with external entities have an hourly synchronized reserve obligation equal to their real-time load (without losses) ratio share of their reserve market's total assignments (adjusted for any bilateral synchronized reserve transactions). Tier 1 charges for each participant equal their ratio share of the total Tier 1 credits based on the amount of Tier 1 synchronized reserve applied to their obligation. Tier 2 hourly charges for each participant equal their reserve market's hourly Tier 2 clearing price times the MWh of Tier 2 synchronized reserve self-scheduled that hour toward their obligation plus that which was purchased from that synchronized reserve market, plus their share of any unrecovered costs incurred by assigned Tier 2 resources above the Tier 2 clearing price, plus their share of costs of those Tier 2 resources assigned in addition to that which was estimated prior to a given hour. Reconciliation Charges: Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the applicable reserve zone's \$/MWh billing determinant calculated as the total applicable reserve zone Synchronized Reserve charges divided by the total MWh of PJM real-time load served in the that market on a two-month billing lag.	Synchronized Reserve Credit Summary Synchronized Reserve Tier 1 Credits Synchronized Reserve Tier 2 Credits Synchronized Reserve Obligation Details Synchronized Reserve Tier 1 Charge Summary Synchronized Reserve Tier 2 Charge Summary Load Response Tier 1 Credits Load Response Tier 2 Credits Synchronized Reserve Load Recon Charge Summary
Non-Synchronized Reserve (OpAgr Schedules 1-3.2.3A.001 & 3.3.5A Manual 28, Section 7)	PJM conducts non-synchronized reserve markets to ensure the capability of generation off-line and available to provide energy within ten minutes as necessary to meet the primary reserve requirement. Credits: Hourly credits provided to generation resources supplying non-synchronized reserve at the Non-Synchronized Reserve Clearing Price. Additional credits provided to non-synchronized reserve resources for any portion of non-synchronized reserve opportunity costs not recovered via Non-Synchronized Reserve Market Clearing Price revenues. Charges: PJM LSEs that are not part of an agreement to share reserves with external entities have an hourly non-synchronized reserve obligation equal to their real-time load (without losses) ratio share of their reserve market's total non-synchronized reserve supplied (adjusted for any bilateral non-synchronized reserve transactions). Hourly charges calculated as adjusted obligations times the Non-Synchronized Reserve Market Clearing Price. Additional charges are assessed for any unrecovered cost payments that PJM provides to non-synchronized reserve suppliers based on adjusted obligation ratio shares. Reconciliation Charges: Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the applicable reserve zone's \$/MWh billing determinant calculated as the total applicable reserve zone Non-Synchronized Reserve charges divided by the total MWh of PJM real-time load served in the that market on a two-month billing lag.	Non-Synchronized Reserve Summary Non-Synchronized Reserve Credits Non-Synchronized Reserve Load Recon Charge Summary
Day-ahead Scheduling Reserve (OpAgr Schedules 1-3.2.3A.01 and OATT Schedule 6 Manual 28, Section 19)	PJM conducts day-ahead scheduling reserve markets to ensure the capability of generation and demand resources to meet reserve requirements on a forward basis. Credits: Daily credits provided to eligible generator and demand response resources cleared day-ahead based on their cleared MWh of day-ahead scheduling reserve times the day-ahead scheduling reserve clearing price. Charges: PJM LSEs have an hourly day-ahead scheduling reserve obligation equal to their real-time load (without losses) ratio share of the market's total assignments (adjusted for any bilateral day-ahead scheduling reserve transactions). Total hourly cost of day-ahead scheduling reserve is allocated based on obligation ratio shares. Reconciliation Charges: Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the \$/MWh billing determinant calculated as the total charges divided by the total MWh of PJM real-time load on a two-month billing lag.	Day-ahead Scheduling Reserve Summary Day-ahead Scheduling Reserve Credits Day-ahead Scheduling Reserve Load Recon Charge Summary

Billing Line Item	Description	Reports
Operating Reserve (OpAgr Schedules 1-3.2.3 & 3.3.3 and OATT Schedule 6 Manual 28, Section 5 and Section 11)	To ensure adequate operating reserve and for spot market support, pool-scheduled generation and demand resources and that operate as requested by PJM are guaranteed to fully recover their daily offer amounts. Day-ahead Credits: Daily credits are provided to pool-scheduled generators, demand response, and transactions cleared day-ahead for any portion of their offer amount in excess of their scheduled MWh times day-ahead bus LMP. Balancing Credits: Daily credits for specified operating period segments provided to eligible pool-scheduled generators, demand response, and import transactions in real-time for any portion of their offer amount in excess of: (1) scheduled MWh times day-ahead bus LMP; (2) MWh deviation from day-ahead schedule times real-time bus LMP; (3) any day-ahead operating reserve credits; (4) any day-ahead scheduling reserve market revenues in excess of offer plus opportunity cost; (5) any synchronized reserve market revenues in excess of offer plus opportunity, energy use, and startup costs; (6) any non-synchronized reserve market revenues in excess of opportunity costs and (7) any applicable reactive services credits. Cancellation credits are based on actual costs submitted to PJM Market Settlements. Credits for lost opportunity costs are also provided to generators reduced or suspended by PJM for reliability purposes. Day-ahead Charges: Total daily cost of operating reserve in the day-ahead market excluding the total cost for resources scheduled to provide Black Start Service, Reactive Services or transfer interface control is allocated based on day-ahead load (including cleared demand, demand response, and decrement bids) plus exports ratio shares. Balancing Charges: Total daily cost of operating reserve in the balancing market related to resources identified as Credits for Deviations is allocated based on regional shares of real-time locational deviations from the following day-ahead scheduled quantities of: (1) cleared generation offers (only for generating units not following PJM dispatch instructions and not assessed deviations based on their real-time desired MWh); (2) cleared increment offers and purchase transactions; and (3) cleared demand bids, decrement bids, and sale transactions. Total daily cost of operating reserve in the balancing market related to resources identified as Credits for Reliability is allocated based on regional shares of real-time load (without losses) plus exports. Reconciliation Charges: Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using a \$/MWh billing determinant calculated as the total charges allocated to real-time load plus exports divided by the total MWh of PJM real-time load plus exports on a two-month billing lag.	Operating Reserve Charge Summary Operating Reserve Generator Credit Details Operating Reserve Lost Opportunity Cost Credits Operating Reserve Transaction Credits Operating Reserve Generator Deviations Operating Reserve Deviation Summary Operating Reserve Transaction Credits Operating Reserve for Load Response Credit Details Operating Reserve for Load Response Deviation Charge Summary Operating Reserve for Load Response Charge Allocations Regional Balancing Operating Reserve Charge Summary Balancing Operating Reserve Load Recon Charge Summary
Synchronous Condensing (OpAgr Schedule 1-3.2.3 Manual 28, Section 5)	Credits: Daily credits for condensing and energy use costs are provided to eligible synchronous condensers dispatched by PJM for purposes other than synchronized reserve, post-contingency, or reactive services. Charges: Total daily cost of synchronous condensing (not for synchronized reserve or reactive services) is allocated based on real-time load (without losses) plus export ratio shares. Reconciliation Charges: Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using a \$/MWh billing determinant calculated as the total charges divided by the total MWh of PJM real-time load plus exports on a two-month billing lag.	Synchronous Condensing Credits Synchronous Condensing Charge Summary Synchronous Condensing Load Recon Charge Summary
Reactive Services (OpAgr Schedule 1-3.2.3B Manual 28, Section 5)	Generating resources whose output is altered by PJM for the purpose of maintaining reactive reliability are guaranteed to fully recover their daily offer amounts or compensated for their lost opportunity costs. Credits: Daily credits are calculated for each eligible generator in real-time and equal the operating reserve credits for generation increased, or equal the lost opportunity costs for generation reduced or instructed to condense, to provide reactive services. Charges: Total daily cost of reactive services and the total day-ahead Operating Reserve credits for resources scheduled to provide Reactive Services or transfer interface control is allocated separately for each PJM transmission zone based on real-time load (without losses) ratio shares in the applicable transmission zone. Reconciliation Charges: Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the applicable zone's \$/MWh billing determinant calculated as the total applicable zone's charges divided by the total MWh of real-time load served in the that zone on a two-month billing lag.	Reactive Services Credits Synchronous Condensing Credits Reactive Services Charge Summary Reactive Svcs Load Recon Charge Summary

Billing Line Item	Description	Reports
Black Start Service (OATT Schedule 6A Manual 27, Section 7)	All Transmission Customers purchase this from PJM to ensure the reliable restoration following a shut down of the PJM transmission system. Credits: Monthly credits provided to generators with approved black start revenue requirements. Charges: Monthly pool-wide black start revenue requirements and day-ahead and balancing Operating Reserve credits associated with scheduling resources for black start service or testing allocated as charges to point-to-point customers based on their monthly peak usage of the PJM transmission system. Monthly peak usage equals the total hourly amounts of transmission capacity reserved, and not curtailed by PJM, divided by 24. The remaining black start revenue requirements nominated by each zonal Transmission Owner and day-ahead and balancing Operating Reserve credits associated with scheduling resources for black start service or testing not recovered from point-to-point customers are allocated to the network customers serving load in that transmission zone based on their monthly network service peak load contributions. PJM conducts annual and monthly FTR auctions for the transaction of FTRs at market clearing prices. Net auction revenues are allocated daily to ARR holders and then FTR holders as excess congestion revenues. Charges: Monthly auction charges are calculated for each market participant for each FTR (in 0.1 MW increments) purchased in the annual or monthly auctions based on the FTR's market price. Credits: Monthly auction credits are calculated for each market participant for each FTR (in 0.1 MW increments) sold in the annual or monthly auctions based on the FTR's market price.	Black Start Charge Summary
Financial Transmission Rights Auction (OpAgr Schedule 1-7.3.8 Manual 28, Section 16)	Auction Revenue Rights (ARR) are entitlements to receive an allocation of net FTR auction revenues that are allocated annually and reassigned daily to network and firm point-to-point transmission customers. Credits: Annual FTR auction net revenues are allocated as daily credits based on ARR target allocations, which equal the ARR MW (divided by the number of auction rounds) times the difference between auction clearing prices at the ARR sink and source. Any ARR target deficiencies may be proportionately eliminated by any monthly FTR auction net revenues and excess congestion revenues in that planning period.	FTR Auction Charges and Credits
Auction Revenue Rights (OpAgr Schedule 1-7.4 Manual 28, Section 17)		ARR Target Credits

Billing Line Item	Description	Reports
RPM Auction (OATT Att. DD, Section 5.14 Manual 18, Section 9.3)	<u>Credits:</u> Each sell offer for generation, demand, or qualified transmission upgrade resource MW cleared in an RPM Auction is paid the applicable resource's clearing price in the applicable auction. Resource make-whole payments are also provided to sell offers that clear less than the minimum amount specified. Sell offers are adjusted by approved unit-specific transactions for cleared capacity. <u>Charges:</u> Each buy bid MW cleared in an incremental auction adjusted by cleared buy bid transactions pays the applicable LDA's resource clearing price. Resource make-whole payments for an incremental auction are also allocated as charges to Market Buyers based on the MW shares of cleared buy bids adjusted by cleared buy bid transactions for the incremental auction. Resource make-whole payments for the base residual auction and the portion of the resource make-whole payment for an incremental auction that would be based on PJM cleared buy bids are allocated as charges to LSEs in the applicable LDA via the Final Zonal Capacity Price. <u>Charges:</u> Each LSE is charged for their daily unforced capacity obligation priced at the applicable zonal capacity price for the delivery year.	RPM Auction Charges and Credits RPM Auction Make-Whole Charge Summary RPM Auction Charges RPM Auction Credits
Locational Reliability (OATT Att. DD, Section 5.14 Manual 18, Section 9.2)		Locational Reliability Charge Summary
Capacity Transfer Rights (OATT Att. DD, Section 5.15 Manual 18, Section 9.3)	To recognize the value of import capability to constrained LDAs, Capacity Transfer Rights (CTRs) are allocated to LSEs in those LDAs to offset their higher load charges. <u>Credits:</u> CTRs equal to the unforced capacity imported into the LDA (less any incremental CTRs) are allocated to LSEs in that LDA based on daily unforced capacity obligations. These MW allocations are priced at the difference between the LDA's clearing price and the unconstrained price.	CTR Credit Summary
Incremental Capacity Transfer Rights (OATT Att. DD, Section 5.16, OATT Schedule 12A (b) Manual 18, Section 9.3)	Incremental CTRs are provided to fund for transmission upgrades (not including qualifying transmission upgrades cleared in the Base Residual Auction) that increase import capability into a constrained LDA. Incremental CTRs for Incremental-Rights Eligible Required Transmission Enhancements are determined and allocated as defined in Schedule 12A of the Tariff. <u>Credits:</u> Incremental CTR MW are priced at the sum of: 1) locational price adder of the sink LDA minus that of the Source LDA from the Base Residual Auction; and 2) locational price adder of the sink LDA minus that of the source LDA from the Second Incremental Auction multiplied by the increase in unforced capacity imported into the sink LDA in the Second Incremental Auction compared to the Base Residual Auction, divided by the base unforced capacity imported into the sink LDA. Incremental CTR credits determined for an Incremental-Rights Eligible Required Transmission Enhancement are allocated to the responsible customers that are assigned cost responsibility for the transmission enhancements in accordance with the cost allocations in the appendix to Schedule 12. Responsible customers include Network customers, Transmission Customers with an agreement for Firm Point-to-Point Service, or Merchant Transmission Facility Owners. Network customers serving load in a responsible zone receive credits in proportion to their network service peak load share in that zone.	Incremental CTR Credits Incremental CTR for Required Transmission Enhancement Credits
Auction Specific MW Transaction (OATT Att. DD, Section 5.14 Manual 18, Section 9.3)	Bilateral capacity transactions for multi-day durations are settled in the PJM capacity markets. <u>Charges:</u> Sellers are charged for the transaction MW times the transaction's pricing point for each day for which the transaction is in effect. <u>Credits:</u> Buyers are credited for the transaction MW times the transaction's pricing point for each day for which the transaction is in effect.	Auction Specific MW Transaction Charges and Credits

Demand Resource Compliance Penalty (OATT Att. DD, Section 11 Manual 18, Section 9.1)	Sellers with zonal aggregate committed Demand Resources that cannot demonstrate hourly real-time performance pay a penalty charge which is allocated to Demand Resource providers and, potentially, LSEs. This billing is performed on a three-month lag. Charges: For each non-compliant reduction event, under-compliance MW (on an unforced capacity basis) are charged at the lesser of one divided by the actual number of events during the year or 0.50 of the Weighted Annual Revenue Rate. The Weighted Annual Revenue Rate equals the average rate for all cleared Demand Resources, weighted by the MWs cleared at each price, multiplied by the number of days in the Delivery Year. The total Compliance Penalty Charge for the Delivery Year is capped at the annual revenue received for such resources. Credits: Revenues from events in a given month are allocated to Demand Resources that reduced in excess of their commitment. Any resource credit by event is capped at their excess MW times 1/5th of their Annual Revenue Rate. Revenues above that cap are allocated to LSEs based on their average daily unforced capacity obligations during the month of the event.	DR and ILR Compliance Penalty Ch and Cr DR and ILR Compliance Penalty Residual Credit Summary
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Billing Line Item	Description	Reports
Capacity Resource Deficiency (OATT Att. DD, Section 8 Manual 18, Section 9.1)	Capacity resources that are unable or unavailable to deliver unforced capacity, and do not obtain replacement unforced capacity to satisfy their cleared sell offer pay this charge which is allocated to eligible LSEs. Charges: Each capacity resource's deficiency MW for each day it is deficient pays the daily deficiency rate. Credits: Total revenues each day are allocated to LSEs that paid a Locational Reliability charge that day based on their daily unforced capacity obligations.	Non-Compliance Charge Summary Deficiency Credit Summary
Generation Resource Rating Test Failure (OATT Att. DD, Section 7 Manual 18, Section 9.1)	Generation capacity resources that fail a capacity test pay this charge which is allocated to eligible LSEs. This billing is performed in the June billing cycle after the conclusion of the delivery year. Charges: Each capacity resource's installed capacity minus its highest rating in the relevant testing period (on an unforced capacity basis) pays a daily deficiency rate which is the weighted average capacity resource clearing price plus the higher of: 1) 0.2 times the weighted average capacity resource clearing price or 2) \$20/MW-day; Credits: Total revenues each day are allocated to LSEs that paid a Locational Reliability charge that day based on their daily unforced capacity obligations.	Non-Compliance Charge Summary Deficiency Credit Summary
Qualifying Transmission Upgrade Compliance Penalty (OATT Att. DD, Section 12 Manual 18, Section 9.1)	Cleared qualifying transmission upgrades delayed in coming into service for the applicable delivery year pay a daily penalty charge which is allocated to eligible LSEs. Charges: Capacity market sellers with import capacity cleared in a base residual auction based on a qualifying transmission upgrade are charged each day that the upgrade is not in service during the applicable delivery year and the seller does not obtain replacement capacity resources. The import capacity MW are charged at the higher of the following rates: 1) two times the locational price adder of the applicable LDA; or 2) the Net CONE less the clearing price in the applicable LDA. Credits: Total revenues each day are allocated to LSEs that paid a Locational Reliability charge that day based on their daily unforced capacity obligations.	Non-Compliance Charge Summary Deficiency Credit Summary
Peak Season Maintenance Compliance Penalty (OATT Att. DD, Section 9 Manual 18, Section 9.1)	Each generation capacity resource must have available unforced capacity during the peak season to satisfy its cleared MW. This billing is performed in the June billing cycle after the conclusion of the delivery year. Charges: Each generation capacity resource's cleared MW for each day of the peak season that is out-of-service on a maintenance outage not authorized by PJM pays the daily deficiency rate times (1-EFORd). Credits: Total revenues each day are allocated to LSEs that paid a Locational Reliability charge that day based on their daily unforced capacity obligations.	Non-Compliance Charge Summary Deficiency Credit Summary
Peak-Hour Period Availability (OATT Att. DD, Section 10 Manual 18, Section 9.1)	To ensure capacity resource availability during critical peak hours, incentives are provided to resources that exceed expected availability and penalties are assessed to those who fall short. This billing is performed in the August billing cycle after the conclusion of the delivery year. Charges: Net peak period capacity shortfall MW are charged at the weighted average resource clearing price for the applicable LDA (except for FRR capacity that are charged at the LDA's Net CONE). Credits: Total revenues for the delivery year for each LDA are allocated to resources with peak period excesses based on their excess MW. Since these allocations are capped, any remaining credits are allocated to LSEs that paid a Locational Reliability charge based on their daily unforced capacity obligations.	
Load Management Test Failure (OATT Att. DD, Section 11A Manual 18, Section 9.1)	Sellers with committed Demand Resources or nominated IJR that fail performance tests pay a penalty charge which is allocated to eligible LSEs. This billing is performed in the December billing cycle for June-December, then it is performed monthly for January-May. Charges: Net capacity testing shortfall MW are charged daily at the weighted annual revenue rate for the applicable zone plus the greater of 0.2 times that weighted annual revenue rate or \$20/MW-day. Credits: Total revenues each day are allocated to LSEs that paid a Locational Reliability charge that day based on their daily unforced capacity obligations.	Load Management Test Failure Charge Summary Deficiency Credit Summary

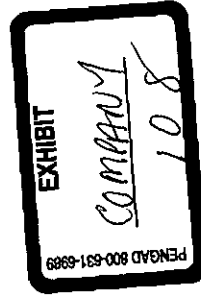
Billing Line Item	Description	Reports
RTO Start-up Cost Recovery (OATT Attachments H-13 and H-14)	All network customers in the AEP Zone pay AEP (expected to end May 2020). <u>Charges:</u> Monthly charges to AEP zonal network customers are calculated based on network service peak load contributions at a 2015 rate of \$96.7615/MW/year.	RTO Startup Cost Recovery Charge Summary
Expansion Cost Recovery (OATT Schedule 13 Manual 27, Section 8)	All network customers (except those in the Dominion, Duke, EKPC and ATSI Zones) pay AEP, ComEd, and Dayton to recover their integration expenses. This charge is expected to continue through April 2015. <u>Charges:</u> For 2015, \$5.42/MW-month of peak load is charged to all network customers serving load in the AEP, ComEd, and Dayton zones and \$2.65/MW-month is charged in all other zones, except Dominion, Duke, ATSI and EKPC. <u>Credits:</u> Total revenues are allocated to ComEd, AEP, and Dayton in accordance with Schedule 13.	Expansion Cost Recovery Charge Summary Expansion Cost Recovery Credit Summary
Unscheduled Transmission Service (OpAgr Sch1-5.3a Manual 28, Section 14)	<u>Charges:</u> Hourly charges to NYISO for any costs incurred due to unscheduled use of the PJM transmission system in accordance with the PJM-NYPP Interconnection Agreement Schedule 6.02. <u>Credits:</u> Total hourly charges are allocated as credits with monthly excess congestion credits.	Hourly Transmission Congestion Credits
Ramapo Phase Angle Regulators (OpAgr Schedule 1-5.3b Manual 28, Section 15)	<u>Credits:</u> PJM's share of monthly carrying charges for Ramapo Phase Angle Regulators (PARs) are credited to NYISO in accordance with the NYPP-PJM PARs Facilities Agreement. <u>Charges:</u> Charges are allocated to PJM Mid-Atlantic transmission owners based on transmission revenue requirement shares.	Ramapo PAR Charge Summary
Michigan-Ontario Interface Phase Angle Regulators (OATT Schedule 10)	Schedule 10 recovers the costs allocated to PJM from MISO for a portion of the revenue requirement associated with the ITC Transmission's Phase Angle Regulators (PARs) on the Michigan-Ontario Interface. <u>Charges:</u> PJM charges each customer using Network Integration and Point-to-Point Transmission Service under this Tariff each month a charge equal to the ITC PARs Rate times the total quantity in MWhs of energy delivered to the load (including losses) that such customer serves in the PJM Region for the month in which the ITC PARs Rate is being calculated.	Schedule 10 Michigan-Ontario PAR Charges
Generation Deactivation (OATT Part V)	Revenues are collected for generators requesting retirement where PJM studies find reliability issues that require the generation to continue operating. Cost allocations to zonal load and firm withdrawal rights are determined by PJM based on the beneficiaries. These responsible customers pay the generation owners a share of the Deactivation Avoidable Cost Rate or the FERC-approved Cost of Service Recovery Rate. Any time that the zonal cost allocations change, notice is provided to the Markets and Reliability Committee, Market Implementation Committee, and Market Settlements Working Group prior to the change being implemented. <u>Charges:</u> Charges are being collected for the First Energy resource Ashtabula 5 based on a Cost of Service Recovery Rate which is ending in May 31, 2015. The monthly charges are allocated on a one-month lag in accordance with the following study results: http://www.pjm.com/~media/planning/gen-retire/2012-2015-zonal-cost-allocation-for-retaining-ashtabula-east-lake-and-lake-shore-generators.aspx . Based on PJM's assessment of the contribution to the need for, and benefits expected to be derived from, the facilities, the zonal percentage cost allocation for September 1, 2012 through May 31, 2015 timeframe is: ATSI (93.80%), DUQ (2.54%), PENELEC (2.09%), and DOM (1.57%). Note that the zonal charges are further allocated based on network service peak load contributions within the applicable zone. Charge refunds are also being provided from September 2008 through February 2017 for a plant in the PSEG zone that was previously collecting payments but has since decided to stay operational. These refunds are being allocated to network customers in the PSEG (41.8707%), PECO (19.1279%), JCPL (25.2497%), Delmarva (6.1420%), AE (6.2832%), and RECO (1.3265%) zones based on the network service peak load contributions within the applicable zones.	Generation Deactivation Charge Summary Generation Deactivation Refund Charge Summary
Deferred Tax Adjustment (OATT Attachments H-8A and H-17C)	<u>Charges:</u> Each Network Customer that serves one or more end-use customers taking distribution service from PPL Electric Utilities Corporation or from Duquesne Light Company under its applicable retail tariff on file with the Pennsylvania Public Utility Commission ("PPL Electric Distribution Customers" and/or "Duquesne Electric Distribution Customers") shall pay a Monthly Deferred Tax Adjustment Charge. This charge permits PPL Electric and Duquesne Light to recover a deferred income tax liability that is currently unfunded due to a Pennsylvania Public Utility decision to flow-through to customers certain income tax benefits.	Deferred Tax Adjustment Charge Summary

From: "Petricoff, M. Howard" <MHPetricoff@vorys.com>
To: "mtharvey@jonesday.com" <mtharvey@jonesday.com>,
Cc: "Campbell, Lael E:(Constellation)" <Lael.Campbell@constellation.com>, "Brady (Fonner), Cynthia:(BSC)" <Cynthia.Brady@constellation.com>
Date: 08/17/2015 01:34 PM
Subject: Scaling List

Martin,

In response to your email asking about the "scaling list" which Lael Campbell referred to in his deposition, the list is kept by PJM on a daily basis in a website which can be accessed by using the following hyperlink <http://www.pjm.com/Search%20Results.aspx?q=factor>.

Below is a representative screen shot from the PJM website that Lael sent me which shows some EDUs scaling at 1 and others above and below 1.
Call or email if you have questions.



Protected View This file originated from an Internet location and might be unsafe. Click for more details. [Enable Editing](#)

Daily Zonal Scaling Factors for 2013/2014 Delivery Year									
A1	A	B	C	D	E	F	G	H	I
1	Daily Zonal Scaling Factors for 2013/2014 Delivery Year								
2	NOTE: Past data trend may not indicate the future trend								
3	**Factors for dates in the future are not final until 36 hours prior to delivery day								
4	**File will be updated monthly with previous months' factors								
5									
6	ZONENAME	EFFECTIVEDAY	TERMINATIONDAY	FACTOR					
7	COMED	6/1/2007 4:00	6/1/2016 4:00	1					
8	DUQ	6/1/2007 4:00	6/1/2016 4:00	1					
9	METED	6/24/2009 4:00	6/1/2016 4:00	1					
10	ATSI	6/1/2011 4:00	6/1/2016 4:00	1					
11	DAY	6/4/2011 4:00	6/1/2016 4:00	1					
12	PENELEC	6/4/2011 4:00	6/1/2016 4:00	1					
13	APS	5/25/2012 4:00	6/1/2016 4:00	1					
14	EKPC	6/1/2013 4:00	6/1/2016 4:00	1					
15	JCPL	11/1/2013 4:00	6/1/2016 4:00	1					
16	DOM	3/27/2015 4:00	6/1/2016 4:00	1					
17	AECO	6/1/2015 4:00	6/2/2015 4:00	0.997525154					
18	AEP	6/1/2015 4:00	6/3/2015 4:00	0.994238891					
19	BGE	6/1/2015 4:00	6/2/2015 4:00	0.969219597					
20	DEOK	6/1/2015 4:00	6/2/2015 4:00	1.005942336					
21	DPL	6/1/2015 4:00	6/2/2015 4:00	1.063256058					
22	PECO	6/1/2015 4:00	6/2/2015 4:00	0.997251015					
23	PEPCO	6/1/2015 4:00	6/2/2015 4:00	0.994198732					
24	PPL	6/1/2015 4:00	6/2/2015 4:00	0.979981486					
25	PSEG	6/1/2015 4:00	6/2/2015 4:00	0.997010979					
26	RECO	6/1/2015 4:00	6/1/2016 4:00	0.882352941					
27	AECO	6/2/2015 4:00	6/3/2015 4:00	0.99712061					
28	BGE	6/2/2015 4:00	6/3/2015 4:00	0.969151922					
29	DEOK	6/2/2015 4:00	6/3/2015 4:00	1.007043427					
30	DPL	6/2/2015 4:00	6/3/2015 4:00	1.063176422					
31	PECO	6/2/2015 4:00	6/3/2015 4:00	0.99727475					
32	PEPCO	6/2/2015 4:00	6/3/2015 4:00	0.994749974					
33	PPL	6/2/2015 4:00	6/3/2015 4:00	0.979584755					
34	PSEG	6/2/2015 4:00	6/3/2015 4:00	0.997207724					
35	AECO	6/3/2015 4:00	6/4/2015 4:00	0.997363297					
36	AEP	6/3/2015 4:00	6/4/2015 4:00	0.994181843					
37	BGE	6/3/2015 4:00	6/4/2015 4:00	0.969341434					
38	DEOK	6/3/2015 4:00	6/5/2015 4:00	1.006851750					

Ready

Howard

VORYS

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Daily Zonal Scaling Factors for 2015/2016 Delivery Year

NOTE: Past data trend may not indicate the future trend

delivery day

****File will be updated monthly with previous months' factors**

ZONENAME	EFFECTIVEDAY	TERMINATIONDAY	FACTOR
COMED	6/1/2007 4:00	6/1/2016 4:00	1
DUQ	6/1/2007 4:00	6/1/2016 4:00	1
METED	6/24/2009 4:00	6/1/2016 4:00	1
ATSI	6/1/2011 4:00	6/1/2016 4:00	1
DAY	6/4/2011 4:00	6/1/2016 4:00	1
PENELEC	6/4/2011 4:00	6/1/2016 4:00	1
APS	5/25/2012 4:00	6/1/2016 4:00	1
EKPC	6/1/2013 4:00	6/1/2016 4:00	1
JCPL	11/1/2013 4:00	6/1/2016 4:00	1
DOM	3/27/2015 4:00	6/1/2016 4:00	1
AECO	6/1/2015 4:00	6/2/2015 4:00	0.997525154
AEP	6/1/2015 4:00	6/3/2015 4:00	0.994238891
BGE	6/1/2015 4:00	6/2/2015 4:00	0.969219597
DEOK	6/1/2015 4:00	6/2/2015 4:00	1.005942336
DPL	6/1/2015 4:00	6/2/2015 4:00	1.063256058
PECO	6/1/2015 4:00	6/2/2015 4:00	0.997251015
PEPCO	6/1/2015 4:00	6/2/2015 4:00	0.994198732
PPL	6/1/2015 4:00	6/2/2015 4:00	0.979981486
PSEG	6/1/2015 4:00	6/2/2015 4:00	0.997010979
RECO	6/1/2015 4:00	6/1/2016 4:00	0.882352941
AECO	6/2/2015 4:00	6/3/2015 4:00	0.99712061
BGE	6/2/2015 4:00	6/3/2015 4:00	0.969151922
DEOK	6/2/2015 4:00	6/3/2015 4:00	1.007043427
DPL	6/2/2015 4:00	6/3/2015 4:00	1.063176422
PECO	6/2/2015 4:00	6/3/2015 4:00	0.99727475
PEPCO	6/2/2015 4:00	6/3/2015 4:00	0.994749974
PPL	6/2/2015 4:00	6/3/2015 4:00	0.979584755
PSEG	6/2/2015 4:00	6/3/2015 4:00	0.997207724
AECO	6/3/2015 4:00	6/4/2015 4:00	0.997363297
AEP	6/3/2015 4:00	6/4/2015 4:00	0.994181843
BGE	6/3/2015 4:00	6/4/2015 4:00	0.969341434
DEOK	6/3/2015 4:00	6/5/2015 4:00	1.006851759
DPL	6/3/2015 4:00	6/4/2015 4:00	1.063375534
PECO	6/3/2015 4:00	6/4/2015 4:00	0.997642801
PEPCO	6/3/2015 4:00	6/4/2015 4:00	0.994732738
PPL	6/3/2015 4:00	6/4/2015 4:00	0.979471462
PSEG	6/3/2015 4:00	6/4/2015 4:00	0.997188046
AECO	6/4/2015 4:00	6/5/2015 4:00	0.997444219
AEP	6/4/2015 4:00	6/5/2015 4:00	0.994387246
BGE	6/4/2015 4:00	6/5/2015 4:00	0.969395594
DPL	6/4/2015 4:00	6/5/2015 4:00	1.063495037

PECO	6/4/2015 4:00	6/5/2015 4:00	0.997619048
PEPCO	6/4/2015 4:00	6/5/2015 4:00	0.994612106
PPL	6/4/2015 4:00	6/5/2015 4:00	0.979443143
PSEG	6/4/2015 4:00	6/5/2015 4:00	0.997296284
AECO	6/5/2015 4:00	6/6/2015 4:00	0.99667599
AEP	6/5/2015 4:00	6/8/2015 4:00	0.994866848
BGE	6/5/2015 4:00	6/6/2015 4:00	0.968664945
DEOK	6/5/2015 4:00	6/7/2015 4:00	1.000425502
DPL	6/5/2015 4:00	6/6/2015 4:00	1.063455199
PECO	6/5/2015 4:00	6/6/2015 4:00	0.997595295
PEPCO	6/5/2015 4:00	6/6/2015 4:00	0.994732738
PPL	6/5/2015 4:00	6/6/2015 4:00	0.979244956
PSEG	6/5/2015 4:00	6/6/2015 4:00	0.997276602
AECO	6/6/2015 4:00	6/9/2015 4:00	0.996231767
BGE	6/6/2015 4:00	6/8/2015 4:00	0.96877312
DPL	6/6/2015 4:00	6/9/2015 4:00	1.063614566
PECO	6/6/2015 4:00	6/8/2015 4:00	0.997571544
PEPCO	6/6/2015 4:00	6/7/2015 4:00	0.9948534
PPL	6/6/2015 4:00	6/7/2015 4:00	0.979329883
PSEG	6/6/2015 4:00	6/7/2015 4:00	0.997188046
DEOK	6/7/2015 4:00	6/8/2015 4:00	1.000401853
PEPCO	6/7/2015 4:00	6/8/2015 4:00	0.99487064
PPL	6/7/2015 4:00	6/10/2015 4:00	0.97934404
PSEG	6/7/2015 4:00	6/8/2015 4:00	0.997079831
AEP	6/8/2015 4:00	6/9/2015 4:00	0.994455732
BGE	6/8/2015 4:00	6/9/2015 4:00	0.968786644
DEOK	6/8/2015 4:00	6/10/2015 4:00	1.000425502
PECO	6/8/2015 4:00	6/9/2015 4:00	0.997559669
PEPCO	6/8/2015 4:00	6/9/2015 4:00	0.9948534
PSEG	6/8/2015 4:00	6/9/2015 4:00	0.997089668
AECO	6/9/2015 4:00	6/10/2015 4:00	0.996312505
AEP	6/9/2015 4:00	6/10/2015 4:00	0.994489979
BGE	6/9/2015 4:00	6/10/2015 4:00	0.970982455
DPL	6/9/2015 4:00	6/10/2015 4:00	1.063415365
PECO	6/9/2015 4:00	6/11/2015 4:00	0.99758342
PEPCO	6/9/2015 4:00	6/10/2015 4:00	0.994818922
PSEG	6/9/2015 4:00	6/10/2015 4:00	0.996981475
AECO	6/10/2015 4:00	6/11/2015 4:00	0.996352879
AEP	6/10/2015 4:00	6/11/2015 4:00	0.994604151
BGE	6/10/2015 4:00	6/11/2015 4:00	0.968002901
DEOK	6/10/2015 4:00	6/11/2015 4:00	1.000472802
DPL	6/10/2015 4:00	6/11/2015 4:00	1.063136609
PEPCO	6/10/2015 4:00	6/11/2015 4:00	0.994594876
PPL	6/10/2015 4:00	6/11/2015 4:00	0.979230803
PSEG	6/10/2015 4:00	6/11/2015 4:00	0.99689297
AECO	6/11/2015 4:00	6/12/2015 4:00	0.996514408
AEP	6/11/2015 4:00	6/12/2015 4:00	0.994467147

BGE	6/11/2015 4:00	6/12/2015 4:00	0.968475697
DEOK	6/11/2015 4:00	6/12/2015 4:00	1.00061473
DPL	6/11/2015 4:00	6/13/2015 4:00	1.063256058
PECO	6/11/2015 4:00	6/12/2015 4:00	0.99753592
PEPCO	6/11/2015 4:00	6/12/2015 4:00	0.994577645
PPL	6/11/2015 4:00	6/12/2015 4:00	0.979372353
PSEG	6/11/2015 4:00	6/13/2015 4:00	0.996833976
AECO	6/12/2015 4:00	6/13/2015 4:00	0.996433637
AEP	6/12/2015 4:00	6/15/2015 4:00	0.994421488
BGE	6/12/2015 4:00	6/13/2015 4:00	0.971716606
DEOK	6/12/2015 4:00	6/13/2015 4:00	1.000496454
PECO	6/12/2015 4:00	6/13/2015 4:00	0.997500298
PEPCO	6/12/2015 4:00	6/15/2015 4:00	0.994525958
PPL	6/12/2015 4:00	6/13/2015 4:00	0.979174194
AECO	6/13/2015 4:00	6/17/2015 4:00	0.996918461
BGE	6/13/2015 4:00	6/15/2015 4:00	0.968205472
DEOK	6/13/2015 4:00	6/14/2015 4:00	1.000401853
DPL	6/13/2015 4:00	6/16/2015 4:00	1.063375534
PECO	6/13/2015 4:00	6/15/2015 4:00	0.997524045
PPL	6/13/2015 4:00	6/14/2015 4:00	0.979273263
PSEG	6/13/2015 4:00	6/14/2015 4:00	0.99685364
DEOK	6/14/2015 4:00	6/15/2015 4:00	1.000425502
PPL	6/14/2015 4:00	6/15/2015 4:00	0.979287418
PSEG	6/14/2015 4:00	6/15/2015 4:00	0.996676692
AEP	6/15/2015 4:00	6/16/2015 4:00	0.994250301
BGE	6/15/2015 4:00	6/16/2015 4:00	0.968232487
DEOK	6/15/2015 4:00	6/16/2015 4:00	1.000496454
PECO	6/15/2015 4:00	6/16/2015 4:00	0.99753592
PEPCO	6/15/2015 4:00	6/16/2015 4:00	0.994543187
PPL	6/15/2015 4:00	6/16/2015 4:00	0.979273263
PSEG	6/15/2015 4:00	6/16/2015 4:00	0.996627552
AEP	6/16/2015 4:00	6/17/2015 4:00	0.994318769
BGE	6/16/2015 4:00	6/17/2015 4:00	0.968137939
DEOK	6/16/2015 4:00	6/17/2015 4:00	1.000401853
DPL	6/16/2015 4:00	6/17/2015 4:00	1.063335705
PECO	6/16/2015 4:00	6/18/2015 4:00	0.997500298
PEPCO	6/16/2015 4:00	6/17/2015 4:00	0.994663802
PPL	6/16/2015 4:00	6/17/2015 4:00	0.979202497
PSEG	6/16/2015 4:00	6/17/2015 4:00	0.996588242
AECO	6/17/2015 4:00	6/18/2015 4:00	0.997241939
AEP	6/17/2015 4:00	6/18/2015 4:00	0.994455732
BGE	6/17/2015 4:00	6/18/2015 4:00	0.968759597
DEOK	6/17/2015 4:00	6/18/2015 4:00	1.004176059
DPL	6/17/2015 4:00	6/18/2015 4:00	1.063415365
PEPCO	6/17/2015 4:00	6/18/2015 4:00	0.994784447
PPL	6/17/2015 4:00	6/18/2015 4:00	0.979938964
PSEG	6/17/2015 4:00	6/18/2015 4:00	0.996578415

AECO	6/18/2015 4:00	6/19/2015 4:00	0.997322841
AEP	6/18/2015 4:00	6/19/2015 4:00	0.994489979
BGE	6/18/2015 4:00	6/19/2015 4:00	0.969260206
DEOK	6/18/2015 4:00	6/19/2015 4:00	1.000496454
DPL	6/18/2015 4:00	6/19/2015 4:00	1.063335705
PECO	6/18/2015 4:00	6/19/2015 4:00	0.997488424
PEPCO	6/18/2015 4:00	6/19/2015 4:00	0.994991334
PPL	6/18/2015 4:00	6/19/2015 4:00	0.97985393
PSEG	6/18/2015 4:00	6/19/2015 4:00	0.996499808
AECO	6/19/2015 4:00	6/20/2015 4:00	0.997646581
AEP	6/19/2015 4:00	6/22/2015 4:00	0.994638408
BGE	6/19/2015 4:00	6/20/2015 4:00	0.967611505
DEOK	6/19/2015 4:00	6/21/2015 4:00	1.000401853
DPL	6/19/2015 4:00	6/20/2015 4:00	1.064013192
PECO	6/19/2015 4:00	6/20/2015 4:00	0.997429061
PEPCO	6/19/2015 4:00	6/20/2015 4:00	0.994974091
PPL	6/19/2015 4:00	6/20/2015 4:00	0.979641411
PSEG	6/19/2015 4:00	6/20/2015 4:00	0.996480158
AECO	6/20/2015 4:00	6/23/2015 4:00	0.997727549
BGE	6/20/2015 4:00	6/22/2015 4:00	0.967395698
DPL	6/20/2015 4:00	6/22/2015 4:00	1.064172727
PECO	6/20/2015 4:00	6/22/2015 4:00	0.997524045
PEPCO	6/20/2015 4:00	6/22/2015 4:00	0.994956847
PPL	6/20/2015 4:00	6/23/2015 4:00	0.979726408
PSEG	6/20/2015 4:00	6/21/2015 4:00	0.996509633
DEOK	6/21/2015 4:00	6/23/2015 4:00	1.004128408
PSEG	6/21/2015 4:00	6/22/2015 4:00	0.996480158
AEP	6/22/2015 4:00	6/23/2015 4:00	0.994318769
BGE	6/22/2015 4:00	6/23/2015 4:00	0.967355245
DPL	6/22/2015 4:00	6/23/2015 4:00	1.063933443
PECO	6/22/2015 4:00	6/23/2015 4:00	0.997559669
PEPCO	6/22/2015 4:00	6/23/2015 4:00	0.994974091
PSEG	6/22/2015 4:00	6/23/2015 4:00	0.996401566
AECO	6/23/2015 4:00	6/24/2015 4:00	0.997768038
AEP	6/23/2015 4:00	6/24/2015 4:00	0.994330181
BGE	6/23/2015 4:00	6/24/2015 4:00	0.967341762
DEOK	6/23/2015 4:00	6/24/2015 4:00	1.004485901
DPL	6/23/2015 4:00	6/24/2015 4:00	1.064092954
PECO	6/23/2015 4:00	6/24/2015 4:00	0.997571544
PEPCO	6/23/2015 4:00	6/24/2015 4:00	0.995163807
PPL	6/23/2015 4:00	6/24/2015 4:00	0.979655576
PSEG	6/23/2015 4:00	6/24/2015 4:00	0.996332808
AECO	6/24/2015 4:00	6/25/2015 4:00	0.998132586
AEP	6/24/2015 4:00	6/25/2015 4:00	0.994284534
BGE	6/24/2015 4:00	6/25/2015 4:00	0.968151445
DEOK	6/24/2015 4:00	6/25/2015 4:00	1.004366709
DPL	6/24/2015 4:00	6/25/2015 4:00	1.064172727

PECO	6/24/2015 4:00	6/25/2015 4:00	0.997440933
PEPCO	6/24/2015 4:00	6/25/2015 4:00	0.995543456
PPL	6/24/2015 4:00	6/25/2015 4:00	0.979641411
PSEG	6/24/2015 4:00	6/25/2015 4:00	0.996264059
AECO	6/25/2015 4:00	6/26/2015 4:00	0.998254162
AEP	6/25/2015 4:00	6/29/2015 4:00	0.993178874
BGE	6/25/2015 4:00	6/26/2015 4:00	0.967449641
DEOK	6/25/2015 4:00	6/26/2015 4:00	1.000567416
DPL	6/25/2015 4:00	6/26/2015 4:00	1.064092954
PECO	6/25/2015 4:00	6/26/2015 4:00	0.997429061
PEPCO	6/25/2015 4:00	6/26/2015 4:00	0.995439886
PPL	6/25/2015 4:00	6/26/2015 4:00	0.979627247
PSEG	6/25/2015 4:00	6/26/2015 4:00	0.996254239
AECO	6/26/2015 4:00	6/27/2015 4:00	0.998416308
BGE	6/26/2015 4:00	6/27/2015 4:00	0.967004793
DEOK	6/26/2015 4:00	6/27/2015 4:00	1.000472802
DPL	6/26/2015 4:00	6/27/2015 4:00	1.064252512
PECO	6/26/2015 4:00	6/27/2015 4:00	0.997512171
PEPCO	6/26/2015 4:00	6/27/2015 4:00	0.995543456
PPL	6/26/2015 4:00	6/27/2015 4:00	0.979528105
PSEG	6/26/2015 4:00	6/27/2015 4:00	0.996283701
AECO	6/27/2015 4:00	6/30/2015 4:00	0.99878133
BGE	6/27/2015 4:00	6/29/2015 4:00	0.967490102
DEOK	6/27/2015 4:00	6/28/2015 4:00	1.000496454
DPL	6/27/2015 4:00	6/30/2015 4:00	1.064172727
PECO	6/27/2015 4:00	6/29/2015 4:00	0.997524045
PEPCO	6/27/2015 4:00	6/30/2015 4:00	0.996027065
PPL	6/27/2015 4:00	6/28/2015 4:00	0.979655576
PSEG	6/27/2015 4:00	6/28/2015 4:00	0.996313164
DEOK	6/28/2015 4:00	6/29/2015 4:00	1.000567416
PPL	6/28/2015 4:00	6/29/2015 4:00	0.979669742
PSEG	6/28/2015 4:00	6/29/2015 4:00	0.996244418
AEP	6/29/2015 4:00	6/30/2015 4:00	0.993110563
BGE	6/29/2015 4:00	6/30/2015 4:00	0.96750359
DEOK	6/29/2015 4:00	6/30/2015 4:00	1.000496454
PECO	6/29/2015 4:00	6/30/2015 4:00	0.997571544
PPL	6/29/2015 4:00	6/30/2015 4:00	0.979655576
PSEG	6/29/2015 4:00	6/30/2015 4:00	0.996175682
AECO	6/30/2015 4:00	7/1/2015 4:00	0.998821904
AEP	6/30/2015 4:00	7/1/2015 4:00	0.992996733
BGE	6/30/2015 4:00	7/1/2015 4:00	0.966964373
DEOK	6/30/2015 4:00	7/1/2015 4:00	1.000543761
DPL	6/30/2015 4:00	7/1/2015 4:00	1.010068666
PECO	6/30/2015 4:00	7/1/2015 4:00	0.997559669
PEPCO	6/30/2015 4:00	7/1/2015 4:00	0.996078908
PPL	6/30/2015 4:00	7/1/2015 4:00	0.979698074
PSEG	6/30/2015 4:00	7/1/2015 4:00	0.996146227

AECO	7/1/2015 4:00	7/2/2015 4:00	1.000244091
AEP	7/1/2015 4:00	7/2/2015 4:00	0.993065028
BGE	7/1/2015 4:00	7/2/2015 4:00	0.966883542
DEOK	7/1/2015 4:00	7/2/2015 4:00	1.005153905
DPL	7/1/2015 4:00	7/2/2015 4:00	1.010032731
PECO	7/1/2015 4:00	7/2/2015 4:00	0.997678433
PEPCO	7/1/2015 4:00	7/2/2015 4:00	0.99666684
PPL	7/1/2015 4:00	7/2/2015 4:00	0.980151612
PSEG	7/1/2015 4:00	7/2/2015 4:00	0.996529284
AECO	7/2/2015 4:00	7/3/2015 4:00	1.002487156
AEP	7/2/2015 4:00	7/6/2015 4:00	0.99319026
BGE	7/2/2015 4:00	7/3/2015 4:00	0.9669509
DEOK	7/2/2015 4:00	7/7/2015 4:00	1.00061473
DPL	7/2/2015 4:00	7/3/2015 4:00	1.015488071
PECO	7/2/2015 4:00	7/3/2015 4:00	0.997904163
PEPCO	7/2/2015 4:00	7/3/2015 4:00	0.997047637
PPL	7/2/2015 4:00	7/3/2015 4:00	0.979882273
PSEG	7/2/2015 4:00	7/3/2015 4:00	0.996794651
AECO	7/3/2015 4:00	7/7/2015 4:00	1.00269157
BGE	7/3/2015 4:00	7/4/2015 4:00	0.967449641
DPL	7/3/2015 4:00	7/7/2015 4:00	1.01566972
PECO	7/3/2015 4:00	7/6/2015 4:00	0.997975467
PEPCO	7/3/2015 4:00	7/7/2015 4:00	0.996926443
PPL	7/3/2015 4:00	7/4/2015 4:00	0.97992479
PSEG	7/3/2015 4:00	7/4/2015 4:00	0.996774989
BGE	7/4/2015 4:00	7/6/2015 4:00	0.967072168
PPL	7/4/2015 4:00	7/5/2015 4:00	0.979953137
PSEG	7/4/2015 4:00	7/5/2015 4:00	0.996824144
PPL	7/5/2015 4:00	7/6/2015 4:00	0.979967311
PSEG	7/5/2015 4:00	7/6/2015 4:00	0.99678482
AEP	7/6/2015 4:00	7/7/2015 4:00	0.993851096
BGE	7/6/2015 4:00	7/7/2015 4:00	0.967112598
PECO	7/6/2015 4:00	7/7/2015 4:00	0.997987352
PPL	7/6/2015 4:00	7/7/2015 4:00	0.979528105
PSEG	7/6/2015 4:00	7/7/2015 4:00	0.996588242
AECO	7/7/2015 4:00	7/8/2015 4:00	1.00297789
AEP	7/7/2015 4:00	7/9/2015 4:00	0.99461557
BGE	7/7/2015 4:00	7/8/2015 4:00	0.967058692
DEOK	7/7/2015 4:00	7/8/2015 4:00	1.000591072
DPL	7/7/2015 4:00	7/8/2015 4:00	1.016033212
PECO	7/7/2015 4:00	7/8/2015 4:00	0.997880397
PEPCO	7/7/2015 4:00	7/8/2015 4:00	0.997116904
PPL	7/7/2015 4:00	7/8/2015 4:00	0.979400668
PSEG	7/7/2015 4:00	7/8/2015 4:00	0.996489983
AECO	7/8/2015 4:00	7/9/2015 4:00	1.003182504
BGE	7/8/2015 4:00	7/9/2015 4:00	0.967571034
DEOK	7/8/2015 4:00	7/9/2015 4:00	1.000567416

DPL	7/8/2015 4:00	7/9/2015 4:00	1.015996851
PECO	7/8/2015 4:00	7/9/2015 4:00	0.998046782
PEPCO	7/8/2015 4:00	7/9/2015 4:00	0.997290114
PPL	7/8/2015 4:00	7/9/2015 4:00	0.979145892
PSEG	7/8/2015 4:00	7/9/2015 4:00	0.996362274
AECO	7/9/2015 4:00	7/10/2015 4:00	1.002936977
AEP	7/9/2015 4:00	7/10/2015 4:00	0.994547062
BGE	7/9/2015 4:00	7/10/2015 4:00	0.96666806
DEOK	7/9/2015 4:00	7/10/2015 4:00	1.000591072
DPL	7/9/2015 4:00	7/10/2015 4:00	1.015887784
PECO	7/9/2015 4:00	7/10/2015 4:00	0.998082443
PEPCO	7/9/2015 4:00	7/10/2015 4:00	0.996909132
PPL	7/9/2015 4:00	7/10/2015 4:00	0.979174194
PSEG	7/9/2015 4:00	7/10/2015 4:00	0.996332808
AECO	7/10/2015 4:00	7/11/2015 4:00	1.001058589
AEP	7/10/2015 4:00	7/13/2015 4:00	0.99518684
BGE	7/10/2015 4:00	7/11/2015 4:00	0.967072168
DEOK	7/10/2015 4:00	7/17/2015 4:00	1.000472802
DPL	7/10/2015 4:00	7/11/2015 4:00	1.015851433
PECO	7/10/2015 4:00	7/11/2015 4:00	0.998046782
PEPCO	7/10/2015 4:00	7/11/2015 4:00	0.994026595
PPL	7/10/2015 4:00	7/11/2015 4:00	0.978990261
PSEG	7/10/2015 4:00	7/11/2015 4:00	0.996401566
AECO	7/11/2015 4:00	7/14/2015 4:00	1.001262421
BGE	7/11/2015 4:00	7/13/2015 4:00	0.970208721
DPL	7/11/2015 4:00	7/15/2015 4:00	1.015815085
PECO	7/11/2015 4:00	7/13/2015 4:00	0.998023009
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PPL	7/11/2015 4:00	7/13/2015 4:00	0.979060996
PSEG	7/11/2015 4:00	7/12/2015 4:00	0.996421212
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AEP	7/13/2015 4:00	7/14/2015 4:00	0.994946827
BGE	7/13/2015 4:00	7/14/2015 4:00	0.970168032
PECO	7/13/2015 4:00	7/14/2015 4:00	0.998046782
PEPCO	7/13/2015 4:00	7/14/2015 4:00	0.9941643
PPL	7/13/2015 4:00	7/14/2015 4:00	0.979089293
PSEG	7/13/2015 4:00	7/14/2015 4:00	0.996313164
AECO	7/14/2015 4:00	7/15/2015 4:00	1.001303197
AEP	7/14/2015 4:00	7/15/2015 4:00	0.994684088
BGE	7/14/2015 4:00	7/15/2015 4:00	0.966721921
PECO	7/14/2015 4:00	7/15/2015 4:00	0.997939814
PEPCO	7/14/2015 4:00	7/15/2015 4:00	0.994112656
PPL	7/14/2015 4:00	7/15/2015 4:00	0.979471462
PSEG	7/14/2015 4:00	7/15/2015 4:00	0.996352452
AECO	7/15/2015 4:00	7/16/2015 4:00	1.001140112
AEP	7/15/2015 4:00	7/16/2015 4:00	0.994581315
BGE	7/15/2015 4:00	7/16/2015 4:00	0.966291196

DPL	7/15/2015 4:00	7/16/2015 4:00	1.015851433
PECO	7/15/2015 4:00	7/16/2015 4:00	0.998034895
PEPCO	7/15/2015 4:00	7/16/2015 4:00	0.994233167
PPL	7/15/2015 4:00	7/16/2015 4:00	0.979598918
PSEG	7/15/2015 4:00	7/16/2015 4:00	0.996283701
AECO	7/16/2015 4:00	7/17/2015 4:00	1.001221648
AEP	7/16/2015 4:00	7/17/2015 4:00	0.994558479
BGE	7/16/2015 4:00	7/17/2015 4:00	0.966197026
DPL	7/16/2015 4:00	7/17/2015 4:00	1.016506141
PECO	7/16/2015 4:00	7/18/2015 4:00	0.997939814
PEPCO	7/16/2015 4:00	7/17/2015 4:00	0.994319264
PPL	7/16/2015 4:00	7/17/2015 4:00	0.979768912
PSEG	7/16/2015 4:00	7/18/2015 4:00	0.996165863
AECO	7/17/2015 4:00	7/18/2015 4:00	1.001507128
AEP	7/17/2015 4:00	7/20/2015 4:00	0.994501395
BGE	7/17/2015 4:00	7/18/2015 4:00	0.966358472
DEOK	7/17/2015 4:00	7/20/2015 4:00	1.000662048
DPL	7/17/2015 4:00	7/18/2015 4:00	1.016615341
PEPCO	7/17/2015 4:00	7/18/2015 4:00	0.994267604
PPL	7/17/2015 4:00	7/18/2015 4:00	0.979174194
AECO	7/18/2015 4:00	7/22/2015 4:00	1.001711143
BGE	7/18/2015 4:00	7/20/2015 4:00	0.966049082
DPL	7/18/2015 4:00	7/21/2015 4:00	1.016433354
PECO	7/18/2015 4:00	7/20/2015 4:00	0.997963583
PEPCO	7/18/2015 4:00	7/19/2015 4:00	0.994319264
PPL	7/18/2015 4:00	7/19/2015 4:00	0.979259109
PSEG	7/18/2015 4:00	7/20/2015 4:00	0.996175682
PEPCO	7/19/2015 4:00	7/20/2015 4:00	0.994336486
PPL	7/19/2015 4:00	7/20/2015 4:00	0.979273263
AEP	7/20/2015 4:00	7/23/2015 4:00	0.994455732
BGE	7/20/2015 4:00	7/21/2015 4:00	0.966116324
DEOK	7/20/2015 4:00	7/21/2015 4:00	1.000638388
PECO	7/20/2015 4:00	7/21/2015 4:00	0.997939814
PEPCO	7/20/2015 4:00	7/21/2015 4:00	0.994353707
PPL	7/20/2015 4:00	7/22/2015 4:00	0.979230803
PSEG	7/20/2015 4:00	7/21/2015 4:00	0.996038238
BGE	7/21/2015 4:00	7/22/2015 4:00	0.966049082
DEOK	7/21/2015 4:00	7/22/2015 4:00	1.000709371
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PECO	7/21/2015 4:00	7/22/2015 4:00	0.997904163
PEPCO	7/21/2015 4:00	7/22/2015 4:00	0.994233167
PSEG	7/21/2015 4:00	7/23/2015 4:00	0.996077504
AECO	7/22/2015 4:00	7/23/2015 4:00	1.002119421
BGE	7/22/2015 4:00	7/23/2015 4:00	0.966466132
DEOK	7/22/2015 4:00	7/23/2015 4:00	1.000756698
DPL	7/22/2015 4:00	7/23/2015 4:00	1.016760977
PECO	7/22/2015 4:00	7/23/2015 4:00	0.997868515

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PPL	7/22/2015 4:00	7/23/2015 4:00	0.979188345
AECO	7/23/2015 4:00	7/24/2015 4:00	1.002078578
AEP	7/23/2015 4:00	7/27/2015 4:00	0.994489979
BGE	7/23/2015 4:00	7/24/2015 4:00	0.965753329
DEOK	7/23/2015 4:00	7/25/2015 4:00	1.000780363
DPL	7/23/2015 4:00	7/24/2015 4:00	1.016797393
PECO	7/23/2015 4:00	7/24/2015 4:00	0.997832869
PEPCO	7/23/2015 4:00	7/24/2015 4:00	0.994405376
PPL	7/23/2015 4:00	7/24/2015 4:00	0.979230803
PSEG	7/23/2015 4:00	7/24/2015 4:00	0.995881205
AECO	7/24/2015 4:00	7/28/2015 4:00	1.002160267
BGE	7/24/2015 4:00	7/25/2015 4:00	0.965672701
DPL	7/24/2015 4:00	7/27/2015 4:00	1.016724564
PECO	7/24/2015 4:00	7/25/2015 4:00	0.997797226
PEPCO	7/24/2015 4:00	7/25/2015 4:00	0.994336486
PPL	7/24/2015 4:00	7/25/2015 4:00	0.979202497
PSEG	7/24/2015 4:00	7/26/2015 4:00	0.995930273
BGE	7/25/2015 4:00	7/27/2015 4:00	0.965605521
DEOK	7/25/2015 4:00	7/26/2015 4:00	1.000756698
PECO	7/25/2015 4:00	7/27/2015 4:00	0.997773465
PEPCO	7/25/2015 4:00	7/27/2015 4:00	0.994319264
PPL	7/25/2015 4:00	7/26/2015 4:00	0.97921665
DEOK	7/26/2015 4:00	7/27/2015 4:00	1.000733034
PPL	7/26/2015 4:00	7/27/2015 4:00	0.979230803
PSEG	7/26/2015 4:00	7/27/2015 4:00	0.995871392
AEP	7/27/2015 4:00	7/28/2015 4:00	0.99523257
BGE	7/27/2015 4:00	7/28/2015 4:00	0.965632392
DEOK	7/27/2015 4:00	7/28/2015 4:00	1.000685709
DPL	7/27/2015 4:00	7/28/2015 4:00	1.016760977
PECO	7/27/2015 4:00	7/28/2015 4:00	0.997761585
PEPCO	7/27/2015 4:00	7/28/2015 4:00	0.994336486
PPL	7/27/2015 4:00	7/28/2015 4:00	0.979471462
PSEG	7/27/2015 4:00	7/28/2015 4:00	0.995881205
AECO	7/28/2015 4:00	7/29/2015 4:00	1.001711143
AEP	7/28/2015 4:00	7/29/2015 4:00	0.995701545
BGE	7/28/2015 4:00	7/29/2015 4:00	0.96592807
DEOK	7/28/2015 4:00	7/29/2015 4:00	1.000638388
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PEPCO	7/28/2015 4:00	7/29/2015 4:00	0.993940548
PPL	7/28/2015 4:00	7/29/2015 4:00	0.979287418
PSEG	7/28/2015 4:00	7/29/2015 4:00	0.995851767
AECO	7/29/2015 4:00	7/30/2015 4:00	1.000162714
AEP	7/29/2015 4:00	7/30/2015 4:00	0.995221137
BGE	7/29/2015 4:00	7/30/2015 4:00	0.96524291
DEOK	7/29/2015 4:00	7/30/2015 4:00	1.000733034

DPL	7/29/2015 4:00	7/30/2015 4:00	1.015960492
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PEPCO	7/29/2015 4:00	7/30/2015 4:00	0.99181135
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AECO	7/30/2015 4:00	7/31/2015 4:00	1.000244091
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PECO	7/30/2015 4:00	7/31/2015 4:00	0.997868515
PEPCO	7/30/2015 4:00	7/31/2015 4:00	0.991862755
PPL	7/30/2015 4:00	7/31/2015 4:00	0.979060996
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AEP	7/31/2015 4:00	8/4/2015 4:00	0.994935401
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PEPCO	7/31/2015 4:00	8/1/2015 4:00	0.991879892
PPL	7/31/2015 4:00	8/1/2015 4:00	0.978594332
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BGE	8/1/2015 4:00	8/4/2015 4:00	0.965216061
DEOK	8/1/2015 4:00	8/2/2015 4:00	1.00080403
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PPL	8/1/2015 4:00	8/2/2015 4:00	0.979160043
PSEG	8/1/2015 4:00	8/2/2015 4:00	0.996224778
AECO	8/2/2015 4:00	8/3/2015 4:00	1.012644152
DEOK	8/2/2015 4:00	8/3/2015 4:00	1.000780363
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AECO	8/3/2015 4:00	8/4/2015 4:00	1.012560745
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DPL	8/3/2015 4:00	8/4/2015 4:00	1.016033212
PEPCO	8/3/2015 4:00	8/4/2015 4:00	0.992205593
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PEPCO	8/4/2015 4:00	8/5/2015 4:00	0.992685963

PPL	8/4/2015 4:00	8/5/2015 4:00	0.979060996
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AECO	8/5/2015 4:00	8/6/2015 4:00	1.012894455
AEP	8/5/2015 4:00	8/6/2015 4:00	0.995438407
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PEPCO	8/5/2015 4:00	8/6/2015 4:00	0.992926323
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AECO	8/6/2015 4:00	8/7/2015 4:00	1.001017832
AEP	8/6/2015 4:00	8/7/2015 4:00	0.996193871
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AECO	8/7/2015 4:00	8/8/2015 4:00	1.001221648
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AECO	8/10/2015 4:00	8/11/2015 4:00	1.001303197
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PPL	8/10/2015 4:00	8/11/2015 4:00	0.979542267
PSEG	8/10/2015 4:00	8/11/2015 4:00	0.995930273
AECO	8/11/2015 4:00	8/12/2015 4:00	1.001507128
AEP	8/11/2015 4:00	8/12/2015 4:00	0.995896127

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DEOK	8/26/2015 4:00	8/27/2015 4:00	1.00030727
DEOK	8/27/2015 4:00	6/1/2016 4:00	1.000189067



DELIVERED BY EMAIL

CRA No. D14673

February 18, 2015

James W. Burk
FirstEnergy Corp.
76 South Main Street
Akron, OH 44308

Re: Notification of CBP Auction Results

Dear Mr. Burk:

Pursuant to the requirements of paragraph 9 of the January 28, 2015 Finding and Order of the Public Utility Commission of Ohio ("PUCO" or "Commission"), please find attached a redacted version of the post-auction letter addressed to you (and cc'd to others) that the CBP Manager, CRA International, submitted on January 27, 2015 following the conclusion of the FirstEnergy Ohio Utilities' Competitive Bidding Process Auction to procure supply for Standard Service Offer customers for the FirstEnergy Ohio Utilities.

Compared to the redacted letter submitted on January 27, the attached letter has fewer redactions pursuant to paragraph 9 of the Finding and Order cited above.

Sincerely yours,

CRA INTERNATIONAL, INC.

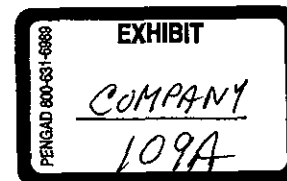
A handwritten signature in cursive script that reads "Bradley A. Miller".

Bradley A. Miller
Vice President

cc:

Angela Hawkins, Chief of Staff, Public Utilities Commission of Ohio
Ray Strom, Public Utilities Commission of Ohio

Attachment





DELIVERED BY EMAIL

CRA No. D14673

January 27, 2015

James W. Burk
FirstEnergy Corp.
76 South Main Street
Akron, OH 44308

Re: Notification of CBP Auction Results

Dear Mr. Burk:

This is to inform you that we have confirmed the results of the FirstEnergy Ohio Utilities' Competitive Bidding Process Auction ("Auction") to procure supply for Standard Service Offer (SSO) customers for the FirstEnergy Ohio Utilities. The Auction began on Tuesday, January 27, 2015 and concluded the same day.

There are three tables attached to this letter.

- Table 1 summarizes the results of the Auction.
- Table 2 shows, for each winning bidder, the number of tranches won for each contract in the auction.
- Table 3 provides the CBP Manager's assessment of the conduct of the auction.

In accordance with the Bidding Rules, winning bidders will be contacted directly by the FirstEnergy Ohio Utilities to execute the Master SSO Supply Agreement no later than three (3) business days following the close of the auction.



James W. Burk
January 27, 2015
Page 2

Sincerely yours,

CRA INTERNATIONAL, INC.

A handwritten signature in black ink that reads "Bradley A. Miller". The signature is fluid and cursive, with the first name "Bradley" being more prominent.

Bradley A. Miller
Vice President

cc:

Thomas W. Johnson, Chairman, Public Utilities Commission of Ohio
Lynn Slaby, Commissioner, Public Utilities Commission of Ohio
M. Beth Trombold, Commissioner, Public Utilities Commission of Ohio
Steven D. Lesser, Commissioner, Public Utilities Commission of Ohio
Asim Z. Haque, Commissioner, Public Utilities Commission of Ohio
Katie Stenman, Chief of Staff, Public Utilities Commission of Ohio
Ray Strom, Public Utilities Commission of Ohio
Steven E. Strah, Senior Vice President and President, FirstEnergy Utilities
Dennis M. Chack, President, Ohio Operations
John Skory, Regional President, The Cleveland Electric Illuminating Company
Randall A. Frame, Regional President, Ohio Edison Company
Linda L. Moss, Regional President, The Toledo Edison Company
Frank Mossburg, Boston Pacific Company

James W. Burk
January 27, 2015
Page 3

Table 1. Summary of SSO Auction Results

Delivery Period (12 months)	June 1, 2015 to May 31, 2016
Number of Registered Bidders	8
Total initial eligibility of Registered Bidders (# tranches)	
Total initial eligibility divided by tranche target	
Number of bidders that submitted bids in round 1	
Number of tranches bid in round 1	68
Number of tranches bid in round 1 divided by tranche target	4.25
Number of tranches to procure in auction (tranche target)	16
Number of tranches procured in auction	16
Number of rounds in clock phase	15
Was there a sealed-bid round?	Yes
Number of winning bidders	6
Starting price range	\$100-\$130
Starting price	
Tranche-weighted average price of winning bids	\$69.18

James W. Burk
January 27, 2015
Page 4

Table 2. Winning Bidders and Tranches Won

Winning Bidder	Number of Winning Tranches	Tranche-Weighted Average Price to be Paid (\$/MWh)
AEP Energy Partners, Inc.	2	\$69.17
ConocoPhillips Company	3	\$69.17
DTE Energy Trading, Inc	4	\$69.17
Exelon Generation Company, LLC	5	\$69.17
FirstEnergy Solutions Corp.	1	\$69.17
NextEra Energy Power Marketing, LLC	1	\$69.38
TOTAL	16	\$69.18

James W. Burk
January 27, 2015
Page 5

Table 3. CBP Manager's Assessment of the Conduct of the Auction

	Question	
1	Were the competitive bidding rules violated?	No
2	Does the CBP Manager believe the auction was open, fair, transparent, and competitive?	Yes
3	Did bidders have sufficient information to prepare for the auction?	Yes. Bidders received information from the competitive bidding process documents, the Information Website, questions-and-answers posted to the Information Website, and bidder information sessions.
4	Was the information generally provided to bidders in accordance with the published timetable? Was the timetable updated appropriately as needed?	Yes
5	Were there any issues and questions left unresolved prior to the auction that created material uncertainty for bidders?	We do not believe that there were any unresolved issues or questions that created material uncertainty for bidders.
6	Were there any procedural problems or errors with the auction, including the electronic bidding process, the back-up bidding process, and communications between bidders and the CBP Manager?	No
7	Were protocols for communication between bidders and the CBP Manager adhered to?	Yes
8	Were there any hardware or software problems or errors, either with the auction system or with its associated communications systems?	No
9	Were there any unanticipated delays during the auction?	No
10	Did unanticipated delays appear to adversely affect bidding in the auction?	No
11	Were appropriate data back-up procedures planned and carried out?	Yes

James W. Burk
January 27, 2015
Page 6

	Question	
12	Were any security breaches observed with the auction process?	No
13	Were protocols followed for communications among FirstEnergy Ohio Utilities, the CBP Manager, the PUCO, and the PUCO's consultant during the auction?	Yes
14	Were the protocols followed for decisions regarding changes in auction parameters (e.g., volume adjustments and price decrements)?	Yes
15	Were the calculations (e.g., for price decrements or bidder eligibility) produced by the auction software double-checked or reproduced off-line by the CBP Manager?	Yes
16	Was there evidence of confusion or misunderstanding on the part of bidders that delayed or impaired the auction?	No
17	Were the communications between the CBP Manager and bidders timely and effective?	Yes
18	Was there evidence that bidders felt unduly rushed during the process?	No
19	Was there any evidence of collusion or improper coordination among bidders?	No
20	Was there any evidence of anti-competitive behavior in the auction?	No
21	Was information made public appropriately? Was confidential and sensitive information treated appropriately?	Yes
22	Were there factors exogenous to the auction (e.g., changes in market environment) that materially affected the auction in unanticipated ways?	No, not that we are aware of.

This foregoing document was electronically filed with the Public Utilities

Commission of Ohio Docketing Information System on

2/18/2015 11:49:31 AM

in

Case No(s). 12-2742-EL-UNC

Summary: Report of Auction Manager - Notification of CBP Auction Results - Updated
Redacted Version electronically filed by Raymond W. Strom on behalf of PUCO Staff



DELIVERED BY EMAIL

CRA No. D14673

November 5, 2014

James W. Burk
FirstEnergy Corp.
76 South Main Street
Akron, OH 44308

Re: Notification of CBP Auction Results

Dear Mr. Burk:

Pursuant to the requirements of paragraph 9 of the October 15, 2014 Finding and Order of the Public Utility Commission of Ohio ("PUCO" or "Commission"), please find attached a redacted version of the post-auction letter addressed to you (and cc'd to others) that the CBP Manager, CRA International, submitted on October 14, 2014 following the conclusion of the FirstEnergy Ohio Utilities' Competitive Bidding Process Auction to procure supply for Standard Service Offer customers for the FirstEnergy Ohio Utilities.

Compared to the redacted letter submitted on October 14, the attached letter has fewer redactions pursuant to paragraph 9 of the Finding and Order cited above.

Sincerely yours,

CRA INTERNATIONAL, INC.

A handwritten signature in black ink that reads "Bradley A. Miller".

Bradley A. Miller
Vice President

cc:

Katie Stenman, Chief of Staff, Public Utilities Commission of Ohio
Ray Strom, Public Utilities Commission of Ohio

Attachment





DELIVERED BY EMAIL

CRA No. D14673

October 14, 2014

James W. Burk
FirstEnergy Corp.
76 South Main Street
Akron, OH 44308

Re: Notification of CBP Auction Results

Dear Mr. Burk:

This is to inform you that we have confirmed the results of the FirstEnergy Ohio Utilities' Competitive Bidding Process Auction ("Auction") to procure supply for Standard Service Offer (SSO) customers for the FirstEnergy Ohio Utilities. The Auction began on Tuesday, October 14, 2014 and concluded the same day.

There are three tables attached to this letter.

- Table 1 summarizes the results of the Auction.
- Table 2 shows, for each winning bidder, the number of tranches won for each contract in the auction.
- Table 3 provides the CBP Manager's assessment of the conduct of the auction.

In accordance with the Bidding Rules, winning bidders will be contacted directly by the FirstEnergy Ohio Utilities to execute the Master SSO Supply Agreement no later than three (3) business days following the close of the auction.



James W. Burk
October 14, 2014
Page 2

Sincerely yours,

CRA INTERNATIONAL, INC.

A handwritten signature in black ink that reads "Bradley A. Miller". The signature is written in a cursive, flowing style.

Bradley A. Miller
Vice President

cc:

Thomas W. Johnson, Chairman, Public Utilities Commission of Ohio
Lynn Slaby, Commissioner, Public Utilities Commission of Ohio
M. Beth Trombold, Commissioner, Public Utilities Commission of Ohio
Steven D. Lesser, Commissioner, Public Utilities Commission of Ohio
Asim Z. Haque, Commissioner, Public Utilities Commission of Ohio
Katie Stenman, Chief of Staff, Public Utilities Commission of Ohio
Ray Strom, Public Utilities Commission of Ohio
Charles E. Jones, Senior Vice President and President, FirstEnergy Utilities
Dennis M. Chack, President, Ohio Operations
John Skory, Regional President, The Cleveland Electric Illuminating Company
Randall A. Frame, Regional President, Ohio Edison Company
Linda L. Moss, Regional President, The Toledo Edison Company
Frank Mossburg, Boston Pacific Company

James W. Burk
October 14, 2014
Page 3

Table 1. Summary of SSO Auction Results

Delivery Period (12 months)	June 1, 2015 to May 31, 2016
Number of Registered Bidders	5
Total initial eligibility of Registered Bidders (# tranches)	
Total initial eligibility divided by tranche target	
Number of bidders that submitted bids in round 1	
Number of tranches bid in round 1	43
Number of tranches bid in round 1 divided by tranche target	2.69
Number of tranches to procure in auction (tranche target)	16
Number of tranches procured in auction	16
Number of rounds in clock phase	18
Was there a sealed-bid round?	No
Number of winning bidders	4
Starting price range	\$100-\$130
Starting price	
Tranche-weighted average price of winning bids	\$73.82

James W. Burk
October 14, 2014
Page 4

Table 2. Winning Bidders and Tranches Won

Winning Bidder	Number of Winning Tranches	Tranche-Weighted Average Price to be Paid (\$/MWh)
AEP Energy Partners, Inc.	5	\$73.82
ConocoPhillips Company	2	\$73.82
Exelon Generation Company, LLC	5	\$73.82
FirstEnergy Solutions Corp.	4	\$73.82
TOTAL	16	\$73.82

James W. Burk
October 14, 2014
Page 5

Table 3. CBP Manager's Assessment of the Conduct of the Auction

	Question	
1	Were the competitive bidding rules violated?	No
2	Does the CBP Manager believe the auction was open, fair, transparent, and competitive?	Yes
3	Did bidders have sufficient information to prepare for the auction?	Yes. Bidders received information from the competitive bidding process documents, the Information Website, questions-and-answers posted to the Information Website, and bidder information sessions.
4	Was the information generally provided to bidders in accordance with the published timetable? Was the timetable updated appropriately as needed?	Yes
5	Were there any issues and questions left unresolved prior to the auction that created material uncertainty for bidders?	We do not believe that there were any unresolved issues or questions that created material uncertainty for bidders.
6	Were there any procedural problems or errors with the auction, including the electronic bidding process, the back-up bidding process, and communications between bidders and the CBP Manager?	No
7	Were protocols for communication between bidders and the CBP Manager adhered to?	Yes
8	Were there any hardware or software problems or errors, either with the auction system or with its associated communications systems?	No
9	Were there any unanticipated delays during the auction?	No
10	Did unanticipated delays appear to adversely affect bidding in the auction?	No
11	Were appropriate data back-up procedures planned and carried out?	Yes

James W. Burk
October 14, 2014
Page 6

	Question	
12	Were any security breaches observed with the auction process?	No
13	Were protocols followed for communications among FirstEnergy Ohio Utilities, the CBP Manager, the PUCO, and the PUCO's consultant during the auction?	Yes
14	Were the protocols followed for decisions regarding changes in auction parameters (e.g., volume adjustments and price decrements)?	Yes
15	Were the calculations (e.g., for price decrements or bidder eligibility) produced by the auction software double-checked or reproduced off-line by the CBP Manager?	Yes
16	Was there evidence of confusion or misunderstanding on the part of bidders that delayed or impaired the auction?	No
17	Were the communications between the CBP Manager and bidders timely and effective?	Yes
18	Was there evidence that bidders felt unduly rushed during the process?	No
19	Was there any evidence of collusion or improper coordination among bidders?	No
20	Was there any evidence of anti-competitive behavior in the auction?	No
21	Was information made public appropriately? Was confidential and sensitive information treated appropriately?	Yes
22	Were there factors exogenous to the auction (e.g., changes in market environment) that materially affected the auction in unanticipated ways?	No, not that we are aware of.

This foregoing document was electronically filed with the Public Utilities

Commission of Ohio Docketing Information System on

11/5/2014 11:53:19 AM

in

Case No(s). 12-2742-EL-UNC

**Summary: Report of Auction Manager - Notification of CBP Auction Results - Updated
Redacted Version electronically filed by Raymond W. Strom on behalf of PUCO Staff**



DELIVERED BY EMAIL

CRA No. D14673

February 19, 2014

James W. Burk
FirstEnergy Corp.
76 South Main Street
Akron, OH 44308

Re: Notification of CBP Auction Results

Dear Mr. Burk:

Pursuant to the requirements of paragraph 9 of the January 29, 2014 Finding and Order of the Public Utility Commission of Ohio ("PUCO" or "Commission"), please find attached a redacted version of the post-auction letter addressed to you (and cc'd to others) that the CBP Manager, CRA International, submitted on January 28, 2014 following the conclusion of the FirstEnergy Ohio Utilities' Competitive Bidding Process Auction to procure supply for Standard Service Offer customers for the FirstEnergy Ohio Utilities.

Compared to the redacted letter submitted on January 28, the attached letter has fewer redactions pursuant to paragraph 9 of the Finding and Order cited above.

Sincerely yours,

CRA INTERNATIONAL, INC.

A handwritten signature in black ink that reads "Bradley A. Miller".

Bradley A. Miller
Vice President

cc:

Eric Weldele, Chief of Staff, Public Utilities Commission of Ohio
Ray Strom, Public Utilities Commission of Ohio

Attachment





DELIVERED BY EMAIL

CRA No. D14673

January 28, 2014

James W. Burk
FirstEnergy Corp.
76 South Main Street
Akron, OH 44308

Re: Notification of CBP Auction Results

Dear Mr. Burk:

This is to inform you that we have confirmed the results of the FirstEnergy Ohio Utilities' Competitive Bidding Process Auction ("Auction") to procure supply for Standard Service Offer (SSO) customers for the FirstEnergy Ohio Utilities. The Auction began on Tuesday, January 28, 2014 and concluded the same day.

There are three tables attached to this letter.

- Table 1 summarizes the results of the Auction.
- Table 2 shows, for each winning bidder, the number of tranches won for each contract in the auction.
- Table 3 provides the CBP Manager's assessment of the conduct of the auction.

In accordance with the Bidding Rules, winning bidders will be contacted directly by the FirstEnergy Ohio Utilities to execute the Master SSO Supply Agreement no later than three (3) business days following the close of the auction.



James W. Burk
January 28, 2014
Page 2

Sincerely yours,

CRA INTERNATIONAL, INC.

A handwritten signature in black ink that reads "Bradley A. Miller". The signature is written in a cursive, flowing style.

Bradley A. Miller
Vice President

cc:

Todd A. Snitchler, Chairman, Public Utilities Commission of Ohio
Lynn Slaby, Commissioner, Public Utilities Commission of Ohio
M. Beth Trombold, Commissioner, Public Utilities Commission of Ohio
Steven D. Lesser, Commissioner, Public Utilities Commission of Ohio
Asim Z. Haque, Commissioner, Public Utilities Commission of Ohio
Katie Stenman, Chief of Staff, Public Utilities Commission of Ohio
Charles E. Jones, Senior Vice President and President, FirstEnergy Utilities
Dennis M. Chack, President, Ohio Operations
John Skory, Regional President, The Cleveland Electric Illuminating Company
Randall A. Frame, Regional President, Ohio Edison Company
Linda L. Moss, Regional President, The Toledo Edison Company
Frank Mossburg, Boston Pacific Company

James W. Burk
January 28, 2014
Page 3

Table 1. Summary of SSO Auction Results

		Delivery Period	
		June 1, 2014 to May 31, 2015	June 1, 2014 to May 31, 2016
Number of Registered Bidders	9		
Total initial eligibility of Registered Bidders (# tranches)			
Total initial eligibility divided by tranche target			
Number of bidders that submitted bids in round 1			
Number of tranches bid in round 1	94	53	41
Number of tranches bid in round 1 divided by tranche target	2.85	3.31	2.41
Number of tranches to procure in auction (tranche target)	33	16	17
Number of tranches procured in auction	33	16	17
Number of rounds in the auction	21		
Number of winning bidders	5	5	4
Starting price range (\$/MWh)		\$80.00-\$105.00	\$80.00-\$105.00
Starting price (\$/MWh)			
Clearing price (\$/MWh)		\$55.83	\$68.31



James W. Burk
January 28, 2014
Page 4

Table 2. Winning Bidders and Tranches Won

Winning Bidder	Number of Winning Tranches		
	Total	Delivery Period	
		June 1, 2014 to May 31, 2015	June 1, 2014 to May 31, 2016
ConocoPhillips Company	2	2	—
Duke Energy Commercial Asset Management, Inc.	4	1	3
Exelon Generation Company, LLC	12	3	9
FirstEnergy Solutions Corp.	7	5	2
The Dayton Power and Light Company	8	5	3
TOTAL	33	16	17

James W. Burk
January 28, 2014
Page 5

Table 3. CBP Manager's Assessment of the Conduct of the Auction

	Question	
1	Were the competitive bidding rules violated?	No
2	Does the CBP Manager believe the auction was open, fair, transparent, and competitive?	Yes
3	Did bidders have sufficient information to prepare for the auction?	Yes. Bidders received information from the competitive bidding process documents, the Information Website, questions-and-answers posted to the Information Website, and bidder information sessions.
4	Was the information generally provided to bidders in accordance with the published timetable? Was the timetable updated appropriately as needed?	Yes
5	Were there any issues and questions left unresolved prior to the auction that created material uncertainty for bidders?	We do not believe that there were any unresolved issues or questions that created material uncertainty for bidders.
6	Were there any procedural problems or errors with the auction, including the electronic bidding process, the back-up bidding process, and communications between bidders and the CBP Manager?	At the end of round 2, the announced prices for round 3 were reported incorrectly due to human error in manually overriding the default price decrements. The correction to the announced prices temporarily affected the reported price decrements and aggregate eligibility for round 3. Bidders were properly informed of the issue via the Messages page and via the Help Desk. We do not believe this adversely affected bidding in the auction or affected the outcome of the auction. All bidders who bid in round 1 and round 2 bid their full eligibility — i.e., the maximum number of tranches they could bid — in round 3 and for a number of subsequent rounds.
7	Were protocols for communication between bidders and the CBP Manager adhered to?	Yes
8	Were there any hardware or software problems or errors, either with the auction system or with its associated communications systems?	No

James W. Burk
January 28, 2014
Page 6

	Question	
9	Were there any unanticipated delays during the auction?	Due to the issue noted in item 6 above, we delayed the opening of round 3 by 10 minutes to confirm the manual error had been corrected and to ensure bidders could submit their bids without being rushed. As noted in item 6 above we do not believe this adversely affected bidding in the auction or affected the outcome of the auction.
10	Did unanticipated delays appear to adversely affect bidding in the auction?	No
11	Were appropriate data back-up procedures planned and carried out?	Yes
12	Were any security breaches observed with the auction process?	No
13	Were protocols followed for communications among FirstEnergy Ohio Utilities, the CBP Manager, the PUCO, and the PUCO's consultant during the auction?	Yes
14	Were the protocols followed for decisions regarding changes in auction parameters (e.g., volume adjustments and price decrements)?	Yes
15	Were the calculations (e.g., for price decrements or bidder eligibility) produced by the auction software double-checked or reproduced off-line by the CBP Manager?	Yes
16	Was there evidence of confusion or misunderstanding on the part of bidders that delayed or impaired the auction?	No
17	Were the communications between the CBP Manager and bidders timely and effective?	Yes
18	Was there evidence that bidders felt unduly rushed during the process?	No
19	Was there any evidence of collusion or improper coordination among bidders?	No



James W. Burk
January 28, 2014
Page 7

	Question	
20	Was there any evidence of anti-competitive behavior in the auction?	No
21	Was information made public appropriately? Was confidential and sensitive information treated appropriately?	Yes
22	Were there factors exogenous to the auction (e.g., changes in market environment) that materially affected the auction in unanticipated ways?	No, not that we are aware of.

This foregoing document was electronically filed with the Public Utilities

Commission of Ohio Docketing Information System on

2/19/2014 3:12:05 PM

in

Case No(s). 12-2742-EL-UNC

**Summary: Report of Auction Manager - Notification of CBP Auction Results - Updated
Redacted Version electronically filed by Raymond W. Strom on behalf of PUCO Staff**



DELIVERED BY EMAIL

CRA No. D14673

November 13, 2013

James W. Burk
FirstEnergy Corp.
76 South Main Street
Akron, OH 44308

Re: Notification of CBP Auction Results

Dear Mr. Burk:

Pursuant to the requirements of paragraph 9 of the October 23, 2013 Finding and Order of the Public Utility Commission of Ohio ("PUCO" or "Commission"), please find attached a redacted version of the post-auction letter addressed to you (and cc'd to others) that the CBP Manager, CRA International, submitted on October 22, 2013 following the conclusion of the FirstEnergy Ohio Utilities' Competitive Bidding Process Auction to procure supply for Standard Service Offer customers for the FirstEnergy Ohio Utilities.

Compared to the redacted letter submitted on October 22, the attached letter has fewer redactions pursuant to paragraph 9 of the Finding and Order cited above.

Sincerely yours,

CRA INTERNATIONAL, INC.

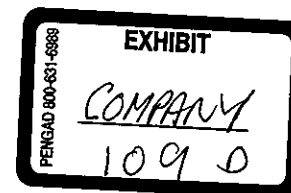
A handwritten signature in black ink that reads "Bradley A. Miller".

Bradley A. Miller
Vice President

cc:

Eric Weldele, Chief of Staff, Public Utilities Commission of Ohio
Ray Strom, Public Utilities Commission of Ohio

Attachment





DELIVERED BY EMAIL

CRA No. D14673

October 22, 2013

James W. Burk
FirstEnergy Corp.
76 South Main Street
Akron, OH 44308

Re: Notification of CBP Auction Results

Dear Mr. Burk:

This is to inform you that we have confirmed the results of the FirstEnergy Ohio Utilities' Competitive Bidding Process Auction ("Auction") to procure supply for Standard Service Offer (SSO) customers for the FirstEnergy Ohio Utilities. The Auction began on Tuesday, October 22, 2013 and concluded the same day.

There are three tables attached to this letter.

- Table 1 summarizes the results of the Auction.
- Table 2 shows, for each winning bidder, the number of tranches won for each contract in the auction.
- Table 3 provides the CBP Manager's assessment of the conduct of the auction.

In accordance with the Bidding Rules, winning bidders will be contacted directly by the FirstEnergy Ohio Utilities to execute the Master SSO Supply Agreement no later than three (3) business days following the close of the auction.



James W. Burk
October 22, 2013
Page 2

Sincerely yours,

CRA INTERNATIONAL, INC.

A handwritten signature in black ink that reads "Bradley A. Miller". The signature is written in a cursive, flowing style.

Bradley A. Miller
Vice President

cc:

Todd A. Snitchler, Chairman, Public Utilities Commission of Ohio
Lynn Slaby, Commissioner, Public Utilities Commission of Ohio
M. Beth Trombold, Commissioner, Public Utilities Commission of Ohio
Steven D. Lesser, Commissioner, Public Utilities Commission of Ohio
Asim Z. Haque, Commissioner, Public Utilities Commission of Ohio
Eric Weldele, Chief of Staff, Public Utilities Commission of Ohio
Charles E. Jones, Senior Vice President and President, FirstEnergy Utilities
Dennis M. Chack, President, Ohio Operations
John Skory, Regional President, The Cleveland Electric Illuminating Company
Randall A. Frame, Regional President, Ohio Edison Company
Linda L. Moss, Regional President, The Toledo Edison Company
Frank Mossburg, Boston Pacific Company

James W. Burk
October 22, 2013
Page 3

Table 1. Summary of SSO Auction Results

		Delivery Period	
		June 1, 2014 to May 31, 2015	June 1, 2014 to May 31, 2016
Number of Registered Bidders	10		
Total initial eligibility of Registered Bidders (# tranches)			
Total initial eligibility divided by tranche target			
Number of bidders that submitted bids in round 1			
Number of tranches bid in round 1	144	76	68
Number of tranches bid in round 1 divided by tranche target	4.36	4.75	4.00
Number of tranches to procure in auction (tranche target)	33	16	17
Number of tranches procured in auction	33	16	17
Number of rounds in the auction	22		
Number of winning bidders	5	4	4
Starting price range (\$/MWh)		\$80.00-\$105.00	\$80.00-\$105.00
Starting price (\$/MWh)			
Clearing price (\$/MWh)		\$50.91	\$59.99



James W. Burk
 October 22, 2013
 Page 4

Table 2. Winning Bidders and Tranches Won

Winning Bidder	Number of Winning Tranches		
	Total	Delivery Period	
		June 1, 2014 to May 31, 2015	June 1, 2014 to May 31, 2016
AEP Energy Partners, Inc.	2	1	1
DTE Energy Trading, Inc.	8	2	6
Duke Energy Commercial Asset Management, Inc.	19	10	9
Exelon Generation Company, LLC	1		1
FirstEnergy Solutions Corp.	3	3	
TOTAL	33	16	17

James W. Burk
October 22, 2013
Page 5

Table 3. CBP Manager's Assessment of the Conduct of the Auction

	Question	
1	Were the competitive bidding rules violated?	No
2	Does the CBP Manager believe the auction was open, fair, transparent, and competitive?	Yes
3	Did bidders have sufficient information to prepare for the auction?	Yes. Bidders received information from the competitive bidding process documents, the Information Website, questions-and-answers posted to the Information Website, and bidder information sessions.
4	Was the information generally provided to bidders in accordance with the published timetable? Was the timetable updated appropriately as needed?	Yes
5	Were there any issues and questions left unresolved prior to the auction that created material uncertainty for bidders?	We do not believe that there were any unresolved issues or questions that created material uncertainty for bidders.
6	Were there any procedural problems or errors with the auction, including the electronic bidding process, the back-up bidding process, and communications between bidders and the CBP Manager?	No
7	Were protocols for communication between bidders and the CBP Manager adhered to?	Yes



James W. Burk
 October 22, 2013
 Page 6

	Question	
8	Were there any hardware or software problems or errors, either with the auction system or with its associated communications systems?	For certain rounds, the external 3 rd party Internet Domain Name Service provider experienced technical difficulties resulting in Bidding Website connection issues for some bidders. Consistent with the auction rules, the CBP Manager: (1) extended 3 rounds of bidding, (2) accepted and successfully submitted fax-based back-up bids, and (3) provided all bidders via the Messages page with the direct IP address of the CBP Manager's Bidding Website so bidders could bypass the external 3 rd party DNS provider and avoid any issues going forward. The participation in, competitiveness of, and results of the auction were not affected.
9	Were there any unanticipated delays during the auction?	No
10	Did unanticipated delays appear to adversely affect bidding in the auction?	No
11	Were appropriate data back-up procedures planned and carried out?	Yes
12	Were any security breaches observed with the auction process?	No
13	Were protocols followed for communications among FirstEnergy Ohio Utilities, the CBP Manager, the PUCO, and the PUCO's consultant during the auction?	Yes
14	Were the protocols followed for decisions regarding changes in auction parameters (e.g., volume adjustments and price decrements)?	Yes
15	Were the calculations (e.g., for price decrements or bidder eligibility) produced by the auction software double-checked or reproduced off-line by the CBP Manager?	Yes



James W. Burk
 October 22, 2013
 Page 7

	Question	
16	Was there evidence of confusion or misunderstanding on the part of bidders that delayed or impaired the auction?	No
17	Were the communications between the CBP Manager and bidders timely and effective?	Yes
18	Was there evidence that bidders felt unduly rushed during the process?	No
19	Was there any evidence of collusion or improper coordination among bidders?	No
20	Was there any evidence of anti-competitive behavior in the auction?	No
21	Was information made public appropriately? Was confidential and sensitive information treated appropriately?	Yes
22	Were there factors exogenous to the auction (e.g., changes in market environment) that materially affected the auction in unanticipated ways?	No, not that we are aware of.

This foregoing document was electronically filed with the Public Utilities

Commission of Ohio Docketing Information System on

11/13/2013 12:22:59 PM

in

Case No(s). 12-2742-EL-UNC

**Summary: Report of Auction Manager - Notification of CBP Auction Results - Updated
Redacted Version electronically filed by Raymond W. Strom on behalf of PUCO Staff**



DELIVERED BY EMAIL

CRA No. D14673

February 13, 2013

James W. Burk
FirstEnergy Corp.
76 South Main Street
Akron, OH 44308

Re: Notification of CBP Auction Results

Dear Mr. Burk:

Pursuant to the requirements of paragraph 9 of the January 23, 2013 Finding and Order of the Public Utility Commission of Ohio ("PUCO" or "Commission"), please find attached a redacted version of the post-auction letter addressed to you (and cc'd to others) that the CBP Manager, CRA International, submitted on January 22, 2013 following the conclusion of the FirstEnergy Ohio Utilities' Competitive Bidding Process Auction to procure supply for Standard Service Offer customers for the FirstEnergy Ohio Utilities.

Compared to the redacted letter submitted on January 22, the attached letter has fewer redactions pursuant to paragraph 9 of the Finding and Order cited above.

Sincerely yours,

CRA INTERNATIONAL, INC.

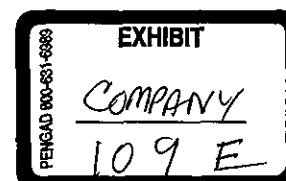
A handwritten signature in black ink that reads "Bradley A. Miller".

Bradley A. Miller
Vice President

cc:

Eric Weldele, Chief of Staff, Public Utilities Commission of Ohio
Ray Strom, Public Utilities Commission of Ohio

Attachment





DELIVERED BY EMAIL

CRA No. D14673

January 22, 2013

James W. Burk
FirstEnergy Corp.
76 South Main Street
Akron, OH 44308

Re: Notification of CBP Auction Results

Dear Mr. Burk:

This is to inform you that we have confirmed the results of the FirstEnergy Ohio Utilities' Competitive Bidding Process Auction ("Auction") to procure supply for Standard Service Offer (SSO) customers for the FirstEnergy Ohio Utilities. The Auction began on Tuesday, January 22, 2013 and concluded the same day.

There are three tables attached to this letter.

- Table 1 summarizes the results of the Auction.
- Table 2 shows, for each winning bidder, the number of tranches won and the tranche-weighted average price to be paid.
- Table 3 provides the CBP Manager's assessment of the conduct of the auction.

In accordance with the Bidding Rules, winning bidders will be contacted directly by the FirstEnergy Ohio Utilities to execute the Master SSO Supply Agreement no later than three (3) business days following the close of the auction.



James W. Burk
January 22, 2013
Page 2

Sincerely yours,

CRA INTERNATIONAL, INC.

A handwritten signature in black ink that reads "Bradley A. Miller". The signature is written in a cursive, flowing style.

Bradley A. Miller
Vice President

cc:

Todd A. Snitchler, Chairman, Public Utilities Commission of Ohio
Lynn Slaby, Commissioner, Public Utilities Commission of Ohio
Steven D. Lesser, Commissioner, Public Utilities Commission of Ohio
Andre Porter, Commissioner, Public Utilities Commission of Ohio
Eric Weldele, Chief of Staff, Public Utilities Commission of Ohio
Charles E. Jones, Senior Vice President and President, FirstEnergy Utilities
Dennis M. Chack, President, Ohio Operations
John Skory, Regional President, The Cleveland Electric Illuminating Company
Dave Karafa, Regional President, Ohio Edison Company
Randall A. Frame, Regional President, The Toledo Edison Company
Frank Mossburg, Boston Pacific Company

James W. Burk
January 22, 2013
Page 3

Table 1. Summary of SSO Auction Results

Period of Delivery	June 1, 2013 - May 31, 2016
Number of Registered Bidders	11
Total initial eligibility of Registered Bidders	
Total initial eligibility divided by tranche target	
Number of bidders that submitted bids in round 1	
Number of tranches bid in round 1	79
Number of tranches bid in round 1 divided by tranche target	4.65
Number of tranches to procure in auction (tranche target)	17 tranches
Number of tranches procured in auction	17 tranches
Number of rounds in clock phase	17
Was there a sealed-bid round?	Yes
Number of winning bidders	4
Starting price range	\$85.00-\$105.00 per MWh
Starting price	
Tranche-weighted average price of winning bids	\$59.17 per MWh



James W. Burk
January 22, 2013
Page 4

Table 2. Winning Bidders and Tranches Won

Winning Bidder	Number of Winning Tranches	Tranche-Weighted Average Price to be Paid (\$/MWh)
AEP Energy Partners, Inc.	6	\$59.17
DTE Energy Trading, Inc.	5	\$59.17
Exelon Generation Company, LLC	1	\$59.14
FirstEnergy Solutions Corp.	5	\$59.17
TOTAL	17	\$59.17

James W. Burk
January 22, 2013
Page 5

Table 3. CBP Manager's Assessment of the Conduct of the Auction

	Question	
1	Were the competitive bidding rules violated?	No
2	Does the CBP Manager believe the auction was open, fair, transparent, and competitive?	Yes
3	Did bidders have sufficient information to prepare for the auction?	Yes. Bidders received information from the competitive bidding process documents, the Information Website, questions-and-answers posted to the Information Website, and bidder information sessions.
4	Was the information generally provided to bidders in accordance with the published timetable? Was the timetable updated appropriately as needed?	Yes
5	Were there any issues and questions left unresolved prior to the auction that created material uncertainty for bidders?	We do not believe that there were any unresolved issues or questions that created material uncertainty for bidders.
6	Were there any procedural problems or errors with the auction, including the electronic bidding process, the back-up bidding process, and communications between bidders and the CBP Manager?	No
7	Were protocols for communication between bidders and the CBP Manager adhered to?	Yes
8	Were there any hardware or software problems or errors, either with the auction system or with its associated communications systems?	No
9	Were there any unanticipated delays during the auction?	No
10	Did unanticipated delays appear to adversely affect bidding in the auction?	No
11	Were appropriate data back-up procedures planned and carried out?	Yes

James W. Burk
January 22, 2013
Page 6

	Question	
12	Were any security breaches observed with the auction process?	No
13	Were protocols followed for communications among FirstEnergy Ohio Utilities, the CBP Manager, the PUCO, and the PUCO's consultant during the auction?	Yes
14	Were the protocols followed for decisions regarding changes in auction parameters (e.g., volume adjustments and price decrements)?	Yes
15	Were the calculations (e.g., for price decrements or bidder eligibility) produced by the auction software double-checked or reproduced off-line by the CBP Manager?	Yes
16	Was there evidence of confusion or misunderstanding on the part of bidders that delayed or impaired the auction?	No
17	Were the communications between the CBP Manager and bidders timely and effective?	Yes
18	Was there evidence that bidders felt unduly rushed during the process?	No
19	Was there any evidence of collusion or improper coordination among bidders?	No
20	Was there any evidence of anti-competitive behavior in the auction?	No
21	Was information made public appropriately? Was confidential and sensitive information treated appropriately?	Yes
22	Were there factors exogenous to the auction (e.g., changes in market environment) that materially affected the auction in unanticipated ways?	No, not that we are aware of.

This foregoing document was electronically filed with the Public Utilities

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in

Case No(s). 10-1284-EL-UNC, 12-2742-EL-UNC

Summary: Report 21-Day Updated Auction Manager Report electronically filed by Raymond W. Strom on behalf of PUCO Staff



DELIVERED BY EMAIL

CRA No. D14673

November 14, 2012

James W. Burk
FirstEnergy Corp.
76 South Main Street
Akron, OH 44308

Re: Notification of CBP Auction Results

Dear Mr. Burk:

Pursuant to the requirements of paragraph 9 of the October 24, 2012 Finding and Order of the Public Utility Commission of Ohio ("PUCO" or "Commission"), please find attached a redacted version of the post-auction letter addressed to you (and cc'd to others) that the CBP Manager, CRA International, submitted on October 23, 2012 following the conclusion of the FirstEnergy Ohio Utilities' Competitive Bidding Process Auction to procure supply for Standard Service Offer customers for the FirstEnergy Ohio Utilities.

Compared to the redacted letter submitted on October 23, the attached letter has fewer redactions pursuant to paragraph 9 of the Finding and Order cited above.

Sincerely yours,

CRA INTERNATIONAL, INC.

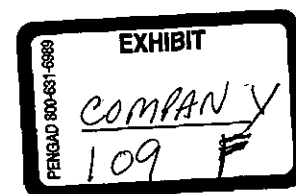
A handwritten signature in black ink that reads "Bradley A. Miller".

Bradley A. Miller
Vice President

cc:

Eric Weldele, Chief of Staff, Public Utilities Commission of Ohio
Ray Strom, Public Utilities Commission of Ohio

Attachment





DELIVERED BY EMAIL

CRA No. D14673

October 23, 2012

James W. Burk
FirstEnergy Corp.
76 South Main Street
Akron, OH 44308

Re: Notification of CBP Auction Results

Dear Mr. Burk:

This is to inform you that we have confirmed the results of the FirstEnergy Ohio Utilities' Competitive Bidding Process Auction ("Auction") to procure supply for Standard Service Offer (SSO) customers for the FirstEnergy Ohio Utilities. The Auction began on Wednesday, October 23, 2012 and concluded the same day.

There are three tables attached to this letter.

- Table 1 summarizes the results of the Auction.
- Table 2 shows, for each winning bidder, the number of tranches won and the tranche-weighted average price to be paid.
- Table 3 provides the CBP Manager's assessment of the conduct of the auction.

In accordance with the Bidding Rules, winning bidders will be contacted directly by the FirstEnergy Ohio Utilities to execute the Master SSO Supply Agreement no later than three (3) business days following the close of the auction.



James W. Burk
October 23, 2012
Page 2

Sincerely yours,

CRA INTERNATIONAL, INC.

A handwritten signature in black ink that reads "Bradley A. Miller". The signature is written in a cursive, flowing style.

Bradley A. Miller
Vice President

cc:

Todd A. Snitchler, Chairman, Public Utilities Commission of Ohio
Lynn Slaby, Commissioner, Public Utilities Commission of Ohio
Cheryl L. Roberto, Commissioner, Public Utilities Commission of Ohio
Steven D. Lesser, Commissioner, Public Utilities Commission of Ohio
Andre Porter, Commissioner, Public Utilities Commission of Ohio
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John Skory, Regional President, The Cleveland Electric Illuminating Company
Dave Karafa, Regional President, Ohio Edison Company
Randall A. Frame, Regional President, The Toledo Edison Company
Frank Mossburg, Boston Pacific Company

James W. Burk
October 23, 2012
Page 3

Table 1. Summary of SSO Auction Results

Period of Delivery	June 1, 2013 - May 31, 2016
Number of Registered Bidders	10
Total initial eligibility of Registered Bidders	
Total initial eligibility divided by tranche target	
Number of bidders that submitted bids in round 1	
Number of tranches bid in round 1	86
Number of tranches bid in round 1 divided by tranche target	5.06
Number of tranches to procure in auction (tranche target)	17 tranches
Number of tranches procured in auction	17 tranches
Number of rounds in clock phase	11
Was there a sealed-bid round?	Yes
Number of winning bidders	5
Starting price range	\$80.00-\$105.00 per MWh
Starting price	
Tranche-weighted average price of winning bids	\$ 60.89 per MWh

James W. Burk
October 23, 2012
Page 4

Table 2. Winning Bidders and Tranches Won

Winning Bidder	Number of Winning Tranches	Tranche-Weighted Average Price to be Paid (\$/MWh)
AEP Energy Partners, Inc.	1	\$ 60.92
DTE Energy Trading, Inc.	5	\$ 60.92
Duke Energy Commercial Asset Management, Inc.	1	\$ 60.92
Exelon Generation Company, LLC	5	\$ 60.82
FirstEnergy Solutions Corp.	5	\$ 60.92
TOTAL	17	\$ 60.89

James W. Burk
October 23, 2012
Page 5

Table 3. CBP Manager's Assessment of the Conduct of the Auction

	Question	
1	Were the competitive bidding rules violated?	No
2	Does the CBP Manager believe the auction was open, fair, transparent, and competitive?	Yes
3	Did bidders have sufficient information to prepare for the auction?	Yes. Bidders received information from the competitive bidding process documents, the Information Website, questions-and-answers posted to the Information Website, and bidder information sessions.
4	Was the information generally provided to bidders in accordance with the published timetable? Was the timetable updated appropriately as needed?	Yes
5	Were there any issues and questions left unresolved prior to the auction that created material uncertainty for bidders?	We do not believe that there were any unresolved issues or questions that created material uncertainty for bidders.
6	Were there any procedural problems or errors with the auction, including the electronic bidding process, the back-up bidding process, and communications between bidders and the CBP Manager?	No
7	Were protocols for communication between bidders and the CBP Manager adhered to?	Yes
8	Were there any hardware or software problems or errors, either with the auction system or with its associated communications systems?	No
9	Were there any unanticipated delays during the auction?	No
10	Did unanticipated delays appear to adversely affect bidding in the auction?	No
11	Were appropriate data back-up procedures planned and carried out?	Yes

James W. Burk
October 23, 2012
Page 6

	Question	
12	Were any security breaches observed with the auction process?	No
13	Were protocols followed for communications among FirstEnergy Ohio Utilities, the CBP Manager, the PUCO, and the PUCO's consultant during the auction?	Yes
14	Were the protocols followed for decisions regarding changes in auction parameters (e.g., volume adjustments and price decrements)?	Yes
15	Were the calculations (e.g., for price decrements or bidder eligibility) produced by the auction software double-checked or reproduced off-line by the CBP Manager?	Yes
16	Was there evidence of confusion or misunderstanding on the part of bidders that delayed or impaired the auction?	No
17	Were the communications between the CBP Manager and bidders timely and effective?	Yes
18	Was there evidence that bidders felt unduly rushed during the process?	No
19	Was there any evidence of collusion or improper coordination among bidders?	No
20	Was there any evidence of anti-competitive behavior in the auction?	No
21	Was information made public appropriately? Was confidential and sensitive information treated appropriately?	Yes
22	Were there factors exogenous to the auction (e.g., changes in market environment) that materially affected the auction in unanticipated ways?	No, not that we are aware of.

This foregoing document was electronically filed with the Public Utilities

Commission of Ohio Docketing Information System on

11/14/2012 4:17:40 PM

in

Case No(s). 10-1284-EL-UNC, 12-2742-EL-UNC

Summary: Report - 21-Day Updated Auction Manager Report electronically filed by Raymond W. Strom on behalf of PUCO Staff

Resolution Regarding Cybersecurity Awareness and Initiatives

WHEREAS, The National Association of Regulatory Utility Commissioners (NARUC), its leadership, its Staff, and its member Commissions have been working to help address cybersecurity issues in the water, gas, electric, telecommunications, and pipeline sectors; *and*

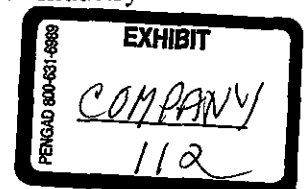
WHEREAS, Our nation's critical utility infrastructure appears to be under increasing cyber-attacks from many different threat sources; *and*

WHEREAS, Threat of cyber-attacks against critical utility systems cannot be eliminated but actions can and ought to be undertaken to reduce the likelihood of successful attack and to mitigate the harmful consequences of an attack; *and*

WHEREAS, Additional efforts continue to be necessary to aid in the prevention of extended interruption to critical utility and pipeline infrastructure from all extraordinary events which could erode the reliable provisions provided by utility and pipeline services (in those jurisdictions having such authority) or compromise the underlying information infrastructure which could have cascading secondary impacts capable of causing significant harm to public health, public safety, and the economy; *and*

WHEREAS, NARUC and its members have undertaken a variety of initiatives to help recognize, communicate, and/or evaluate these threats, vulnerabilities, and potential mitigating actions, including:

- NARUC Cybersecurity State's Summit held July 24, 2013 in Denver, Colorado;
- Publication in February 2013 of "Cybersecurity for State Regulators 2.0 With Sample Questions for Regulators to Ask Utilities" and its predecessor document in June 2012;
- NARUC Forum on Cybersecurity and Critical Infrastructure held November 30-December 1, 2011 in Indianapolis, Indiana;
- NARUC Catastrophic Event Workshop held December 13, 2012 in New York City;
- NARUC Workshop: "Serving National Security: A Conversation with the Department of Homeland Security, Department of Defense and Other Stakeholders," held July 20, 2011 in Los Angeles, California;
- NARUC Committee on Critical Infrastructure workshop regarding the cybersecurity operations center concept held with Lockheed Martin and various electric utilities on February 5, 2013 in Rockville, Maryland;
- NARUC staff on-site trainings of 30 State regulatory commissions (Commissioners and Staff), resulting in the formation of State and multi-State task forces;
- Continued outreach and partnership on cybersecurity issues with: Executive Office of the President, U.S. Department of Energy (DOE), U.S. Department of Homeland Security (DHS), Federal Energy Regulatory Commission (FERC), Federal Communications Commission (FCC), U.S. Environmental Protection Agency (EPA), U.S. Department of Defense (DoD), National Institute of Standards and Technology (NIST), U.S. Dept. of Transportation (DOT), National Association of Water Companies (NAWC), North American Electric Reliability Corporation (NERC), Edison Electric Institute (EEI), American Gas Association (AGA), and others;
- NARUC Committee meetings and workshops including "Cybersecurity: Industry



Assessments & Capability Improvements,” February 3, 2013; “Cyber Security – The States’ Role,” July 24, 2012; “Cybersecurity Questions to Ask Your Utilities”, November 13, 2011; “The Good News: Getting Traction in Cybersecurity,” November 13, 2011; “Don’t Get Hacked! Cybersecurity Boot Camp,” February 13, 2011; and many others;

- Participation in monthly electricity sector threat briefings;
- Participation in monthly oil and gas sector threat briefings;
- Participation in classified briefings at the national, regional, and State levels;
- Twice-monthly conference calls often focused on cybersecurity threats, issues, and related matters;
- Commissioner and Staff applications for government clearance to access classified information; *and*

WHEREAS, NARUC members continue to become better educated in cybersecurity matters and to communicate with regulated utilities on these matters; *and*

WHEREAS, NARUC, its executive leadership, along with its Committee on Critical Infrastructure and other Committees, encourages continued education and edification of its member commissions; *now, therefore, be it*

RESOLVED, That the Board of Directors of the National Association of Regulatory Utility Commissioners, convened at its 2013 Summer Meetings in Denver, Colorado, acknowledges the need for enhanced vigilance against all cybersecurity threats to our nation’s critical utility infrastructure; *and be it further*

RESOLVED, That NARUC encourages member commissions to continue their efforts to give a high priority to monitoring and evaluating cybersecurity threats to utility systems in collaboration with those agencies and entities having cyber-threat management and mitigation expertise; *and be it further*

RESOLVED, That NARUC continues to encourage member commissions to become increasingly knowledgeable about cybersecurity threats to the relevant utility and pipeline sectors and to maintain an open dialogue with their regulated utilities to ensure adequate resources and expertise are being applied to deter, detect, and respond to cyber attacks; *and be it further*

RESOLVED, That NARUC encourages member commissions to continue in partnership with the relevant federal, regional, and State agencies and industry organizations to work together to enhance and strengthen the cybersecurity posture of our nation’s critical utility systems.

*Sponsored by the Committee on Critical Infrastructure
Adopted by the NARUC Board of Directors, July 24, 2013*

Resolution on Physical Security

WHEREAS, Multiple threats have challenged the security of electricity grid networks at both the high-voltage and distribution levels, including cybersecurity, physical security, electromagnetic pulse (EMP) and geomagnetic disturbance (GMD) events, and potentially a black sky event of an all-hazards scenario; *and*

WHEREAS, Electric utilities have recognized these threats historically, and have attempted to mitigate such threats through a variety of measures, especially after the extensive black-out in the Northeast and Canada in 2003 that prompted Congress to mandate certain reliability standards for the bulk electric power system in legislation passed by Congress in 2005; *and*

WHEREAS, The North American Reliability Corporation (NERC) was certified by FERC as the Electric Reliability Organization (ERO) to develop mandatory reliability standards, and to also develop standards for cybersecurity and physical security measures, called the Critical Infrastructure Protection (CIP) standards, and has now adopted version 5.0; *and*

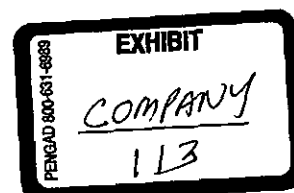
WHEREAS, Historically, the potential physical threats to the bulk electric system have been well documented in several national reports by electric grid experts that have received national attention from utilities, the press, and the Congress, such as the Office of Technology Assessment Report in June, 1990 (*Physical Vulnerability of Electric Systems to National Disasters and Sabotage*), and the National Research Council (NRC) report in 2012, *Terrorism and the Electric Power Delivery System*, The National Academy Press, Washington, D.C.; *and*

WHEREAS, Since those national reports have been published, the threats to industrial control systems such as SCADA equipment from cyber attacks, and the key critical assets from a physical security perspective have been increasing in frequency, sophistication, and persistence; *and*

WHEREAS, The interdependencies of other key critical infrastructure sectors, such as natural gas and water sectors, with the electric sector, have been highlighted in these studies, expert analyses, the GRIDEX II exercise that simulated a concurrent physical and cyber attack, and by several incidents; *and*

WHEREAS, A well-planned attack by certain perpetrator(s) on the Metcalf substation incident near San Jose, California in April, 2013, has prompted a necessary re-assessment by transmission owners and operators of enhanced physical security measures to protect critical infrastructure facilities in all regions of the country reflecting the most up-to-date security techniques and monitoring; *and*

WHEREAS, Most utilities and transmission grid operators recognize that certain vulnerabilities to physical and cybersecurity need to be addressed separately and in conjunction on a dynamic basis reflecting a constantly changing threat environment from a variety of potential actors who desire to harm such critical systems, including individuals and groups, non-State actors, organized crime syndicates, and potentially State actors (foreign governments); *and*



WHEREAS, NARUC members recognize the urgency and severity of this threat environment, both physical and cyber, and especially acknowledge the need to take certain actions in the aftermath of the Metcalf substation incident, and in the analysis and work by NERC, NRC, and other experts leading up to this specific incident that could have resulted in cascading effects throughout the Western Interconnection; *and*

WHEREAS, NARUC members also recognize the need for a thorough and diligent cost-effective analysis for the mitigation measures for physical security by NERC; *and*

WHEREAS, FERC acted promptly under the leadership of Chairman Cheryl LaFleur and her colleagues on March 7, 2014, to direct NERC promptly to develop certain physical security standards based on a definition of “critical facilities” and use of a broad risk assessment methodology by the utilities and transmission owners, without being prescriptive (Docket No. RD14-6-000); *and*

WHEREAS, NERC responded in a timely way by developing such a standard, called CIP 014-1, in a record time of about two months, approving it by 86 percent in a ballot that closed on May 6th, and subsequently submitting such standard in a petition to FERC on May 23rd, that largely followed the criteria in the “roadmap” that FERC set forth in its earlier Order of March 7th; *now, therefore, be it*

RESOLVED, That the Board of Directors of the National Association of Regulatory Utility Commissioners, convened at its Summer Committee Meeting in Dallas, Texas, acknowledges that the protection of “critical facilities” of the electric delivery system is a shared regulatory oversight responsibility of FERC, NERC, and the State Commissions, and commends NERC for taking prompt action to develop a standard based on a comprehensive risk assessment methodology, and urges FERC to give the CIP-014 standard favorable consideration; *and be it further,*

RESOLVED, That State Commissions should devote significant attention to such a standard, along with cybersecurity and other potential hazards to the electricity delivery system, in either a collaborative or other process so that the regulated utilities in the State comply with such a standard, recognizing that the circumstances and geographies in each State may differ substantially; *and be it further,*

RESOLVED, That State Commissions should endeavor to work with their regulated utilities to ensure that such a CIP standard is reviewed promptly in an appropriate forum, in accordance with a cost-benefit methodology used by each Commission.

*Passed by the Committees on Critical Infrastructure and Electricity.
Approved by the NARUC Board of Directors July 16, 2014*