BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

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

DIRECT TESTIMONY

OF

JONATHAN A. LESSER

ON BEHALF OF

FIRSTENERGY SOLUTIONS CORP.

March 26, 2013

PUBLIC VERSION

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I. INTRODUCTION, PURPOSE, AND SUMMARY OF CONCLUSIONS

Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. My name is Jonathan A. Lesser. I am the President of Continental Economics, Inc., an economic consulting firm that provides litigation, valuation, and strategic services to law firms, industry, and government agencies. My business address is 6 Real Place, Sandia Park, NM 87047.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS, EMPLOYMENT EXPERIENCE, AND EDUCATIONAL BACKGROUND.

A. I am an economist with substantial experience in market analysis in the energy industry. I have almost 30 years of experience in the energy industry working with utilities, consumer groups, competitive power producers and marketers, and government regulators. I have provided expert testimony before numerous state utility commissions, as well as before the Federal Energy Regulatory Commission ("FERC"), state legislative committees, and international venues.

Before founding Continental Economics, I was a Partner in the Energy Practice with the consulting firm Bates White, LLC. Prior to that, I was the Director of Regulated Planning for the Vermont Department of Public Service. Previously, I was employed as a Senior Managing Economist at Navigant Consulting. Prior to that, I was the Manager, Economic Analysis, for Green Mountain Power Corporation. I also spent seven years as an Energy Policy Specialist with the Washington State Energy Office, and I worked for Idaho Power Corporation and the Pacific Northwest Utilities Conference Committee (an electric industry trade group), where I specialized in electric load and price forecasting.

I hold MA and PhD degrees in economics from the University of Washington and a BS, with honors, in mathematics and economics from the University of New Mexico. My doctoral fields of specialization were applied microeconomics, econometrics and statistics, and industrial organization and antitrust. I am the coauthor of three textbooks: *Environmental Economics and Policy* (1997), *Fundamentals of Energy Regulation* (2007), and, most recently, *Principles of Utility Corporate Finance* (2011). I have attached a copy of my curriculum vitae as Exhibit JAL-1.

Q. ARE YOU A MEMBER OF ANY PROFESSIONAL ORGANIZATIONS?

A. Yes. I am a member of the International Association for Energy Economics, the Energy Bar Association, and the Society for Benefit-Cost Analysis.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of FirstEnergy Solutions Corp. ("FirstEnergy Solutions" or "FES").

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO ("PUCO")?

A. Yes. I testified in Case Nos. 08-917-EL-UNC and 08-918-EL-UNC, generally referred to as the "AEP POLR Remand" proceeding. I also testified in several cases involving AEP Ohio, including: Case Nos. 11-346-EL-SSO, 11-348-EL-SSO, 11-349-EL-AAM and 11-350-EL-AAM, in Case Nos. 11-501-EL-FOR and 11-502-EL-FOR, and in Case No. 10-2929-EL-UNC. Most recently, I testified in Case No. 12-426-EL-SSO, which involves the application of Dayton Power & Light Company for approval of its Electric Service Plan ("ESP").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses several aspects of Duke Energy Ohio's ("DEO" or "the company") proposal to modify the terms of its ESP to incorporate an embedded-cost based capacity charge.[1] Specifically, I find that DEO's proposal to recover the full embedded costs of the company's so-called "Legacy Generating Assets" by establishing a regulatory asset is unjust, unreasonable and imprudent for the following reasons:

1. DEO's proposal violates the terms of the Stipulation in Case No. 11-3459-EL-SSO, et al.,[2] in which the company agreed to charge customers the PJM market price for capacity. The establishment of the regulatory asset to recover embedded costs through a future nonbypassable charge effectively raises the price DEO will charge its customers for capacity by over 300%.

2. The DEO application fails to acknowledge, recognize, or even discuss the fact that, under the terms of the 2011 Stipulation, the company has been recovering $110 million annually through a nonbypassable Electric Service Stability Charge ("ESSC"), which is in effect for calendar years 2012 – 2014, or $330 million in total. DEO witness Trent appears to deny the existence of the ESSC whatsoever.[3] As the Stipulation itself states, the $330 million is "an amount intended to provide stability and certainty regarding DEO's provision of retail electric service as an FRR entity while continuing to operate under an ESP."[4] Thus, in the aggregate, DEO now seeks to recover over <u>one billion dollars</u> in nonbypassable charges from its customers to

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1 *Application of the Duke Energy Ohio Company for the Establishment of a Charge Pursuant to Revised Code Section 4909.18*, August 29, 2012 ("DEO Application").

2 *In the Matter of the Application of Duke Energy Ohio for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan, Accounting Modifications and Tariffs for Generation Service*, Case No. 11-3549-EL-SSO, et al., Stipulation and Recommendation, October 24, 2011 ("2011 Stipulation").

3 *Application of the Duke Energy Ohio Company for the Establishment of a Charge Pursuant to Revised Code Section 4909.18*, Direct Testimony of B. Keith Trent, March 1, 2013 ("Trent Direct"), p. 12, lines 4-6. "There is no existing rate or tariff that can be adjusted to remedy this financial situation as there is no existing rate or tariff that compensates Duke Energy Ohio for its provision of noncompetitive, wholesale capacity service."

4 2011 Stipulation, p. 16.

compensate the company for uneconomic generating assets. Together, these "financial integrity" payments equate to over $1,500 for each and every DEO customer.

There is no legitimate economic or regulatory basis for allowing DEO to collect the additional $729 million, on top of the $330 million the company is already collecting under the ESSC. Even if one accepts, arguendo, all of Mr. Wathen's calculations, removing the ESSC revenues from DEO's claimed revenue requirement reduces the "revenue to be collected" amount from the proposed $729,122,082 to $399,122,082.

3. The capacity cost prepared by Mr. Wathen uses incorrect capacity market prices, allocates an excessive amount of General Plant to the legacy generating assets, and fails to account for anticipated net income improvements as discussed in the deposition of DEO witness Savoy. With these changes, the revenues to be collected decrease further to $200,447,690

4. Because DEO has agreed to structurally separate its generating assets on or before December 31, 2014, DEO witness Trent's argument that DEO is providing a noncompetitive wholesale service using these assets will no longer be true following structural separation.[5] At that time, capacity sales between the competitive generation affiliate ("Genco") and DEO's electric distribution utility will be overseen by FERC, which has jurisdiction over wholesale transactions. This new Genco will be unable to mandate that DEO's distribution utility purchase capacity from it at an above-market price. Likewise, a properly independent DEO will be free to obtain capacity to satisfy its FRR obligation at the lowest-available market price, and any above-market purchase from the Genco would be imprudent. Removing the final five months' of costs, January 2015 – May 2015, from Mr. Wathen's calculations further reduces the regulatory asset revenue requirement to $124,455,400.

5. The proposed change from charging CRES providers the market-based Final Zonal Capacity Price ("FZCP") to an embedded cost-based price of $224.15/MW-day and

[5] Trent Direct, p. 3, line 20.

establishment of a regulatory asset to recover the difference between this cost-based price and the market-based FZCP results in failure of the "better in the aggregate" test required under R.C. 4928.143(C)(1) for approval of an electric security plan ("ESP"), which I refer to as the "ESP v. MRO" test. With the proposed capacity charge, the present value cost of the ESP is approximately $548.5 million greater than the MRO, using the same ESP v. MRO test prepared by DEO witness Wathen in support of the 2011 Stipulation.[6] Even with the modifications to the regulatory asset amount discussed previously, DEO fails the ESP v. MRO test.

6. The DEO proposal fails to acknowledge that the time for recovery of stranded generation costs, as part of the transition to competition that began in 2001 after passage of S.B. 3, has long passed.

7. The DEO proposal unreasonably concludes that, because the PUCO approved a cost-based, above-market capacity charge for AEP Ohio <u>after</u> approving DEO's 2011 Stipulation agreed to by the settling parties, including PUCO Staff, the PUCO must now change the terms of that Stipulation to allow DEO to collect an additional $729 million in nonbypassable charges to support its uneconomic generating assets.

8. DEO was not forced to join PJM. Rather, the company voluntarily left MISO and joined PJM. DEO was aware of the obligations of membership in PJM and also was aware at the time it joined PJM that the PJM market price for capacity for the 2012-13 planning year would be approximately $16/MW-day. DEO ratepayers should not be forced to further subsidize a management decision to join PJM beyond the ESSC subsidy agreed to in the 2011 Stipulation, especially as DEO agreed to charge the PJM RPM market capacity price under its FRR obligation.

9. DEO witnesses Trent, Savoy, and Wathen wrongly assert that DEO's financial integrity will be harmed <u>but for</u> creation of this new regulatory asset and collection of

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[6] *In the Matter of the Application of Duke Energy Ohio for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan, Accounting Modifications and Tariffs for Generation Service*, Case No. 11-3549-EL-SSO, et al., Supplemental Testimony of William D. Wathen, October 28, 2011 ("Wathen 2011 Supplemental"), Attachment WDW Supp-1.

a total of $729 million in above-market costs over the 34-month period, August 2012 – May 2015, or $257.3 million per year on an annualized basis.[7] In fact, DEO's financial integrity is not in jeopardy. Rather, DEO's legacy generating assets, which are part of DEO's Competitive Power business unit, are uncompetitive in the current market. However, rather than addressing that issue, such as by retiring those assets and purchasing the capacity the company needs to maintain its Fixed Resource Requirement ("FRR") capacity obligation through May 31, 2015, which DEO voluntarily assumed when the company chose to join PJM, DEO insists all of its customers continue to financially support those uncompetitive assets for years to come, including after the company has structurally separated its generating assets into a separate corporate entity by December 31, 2014. Furthermore, Mr. Savoy's pro forma projected income statements contain numerous flaws, notably failing to recognize the $330 million in ESSC revenue DEO will receive under the 2011 Stipulation.

10. Because DEO admits its legacy generating capacity is not competitive and argues that regulation of its "noncompetitive wholesale capacity service"[8] falls under traditional ratemaking principles, the company's use of legacy generating assets is not a "least-cost" approach to meeting that obligation. Consistent with the tenets of "least-cost" planning, DEO should be required to meet its FRR obligation at the lowest possible cost. Because the legacy generating assets are clearly not "least-cost," all of the above-market costs should be disallowed as imprudent.

II. IMPACTS OF THE PROPOSED NEW CHARGE ON DEO CUSTOMERS

Q. HAVE YOU ESTIMATED THE IMPACT OF THE PROPOSED NEW REGULATORY ASSET ON DEO'S CUSTOMERS?

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[7] *Application of the Duke Energy Ohio Company for the Establishment of a Charge Pursuant to Revised Code Section 4909.18*, Direct Testimony of William D. Wathen, March 1, 2013 ("Wathen Direct"), Attachment WDW-1.

[8] Trent Direct, p. 3, line 20.

A. Yes. Using data published in DEO's 2011 FERC Form-1 report, which provides data through December 31, 2011, I have calculated the impact on DEO's residential, commercial, and industrial customers. These impacts are shown in Table 1.

Table 1: Customer Impacts of Requested New Capacity Charge[9]

Line No.	Line Item Description	Amount	Source / Calculation
1	Requested Capacity Charge	$ 729,122,082	Source: Exhibit WDW-1 Conf, Page 3 of 24
2	Average Number of Customers	685,859	Source: 2011 FERC Form 1, Page 304
3	**Capacity Charge ($ per Customer)**	**$ 1,063.08**	Equals: Line 1 / Line 2
4	Capacity Charge Period (in months)	34	Source: Application
5	Annual MWh Sales	20,238,172	Source: 2011 FERC Form 1, Page 304
6	Total MWh Sales Over Capacity Charge Period	57,341,487	Equals: Line 4 x Line 5 /12
7	**Capacity Charge ($ per MWh)**	**$ 12.72**	Equals: Line 1 / Line 6
8	Residential		
9	2011 Residential Customers	610,416	Source: 2011 FERC Form 1, Page 301
10	2011 Residential Sales (MWh)	7,331,858	Source: 2011 FERC Form 1, Page 301
11	Residential Sales/Customer (MWh)	12.01	Equals: Line 10 / Line 9
12	Total Residential Sales/Cust Over Charge Period	34.03	Equals: Line 11 x Line 4 /12
13	**Cost per Residential Customer**	**$ 433**	Equals: Line 7 x Line 12
14	Commercial		
15	2011 Commercial Customers	67,207	Source: 2011 FERC Form 1, Page 301
16	2011 Commercial Sales (MWh)	6,493,122	Source: 2011 FERC Form 1, Page 301
17	Commercial Sales/Customer (MWh)	96.61	Equals: Line 16 / Line 15
18	Total Commercial Sales/Cust Over Charge Period	273.74	Equals: Line 17 x Line 4 /12
19	**Cost per Commercial Customer**	**$ 3,481**	Equals: Line 7 x Line 18
20	Industrial		
21	2011 Industrial Customers	2,222	Source: 2011 FERC Form 1, Page 301
22	2011 Industrial Sales	4,938,881	Source: 2011 FERC Form 1, Page 301
23	Industrial Sales/Customer (MWh)	2,222.72	Equals: Line 22 / Line 21
24	Total Industrial Sales/Cust Over Charge Period	6,297.70	Equals: Line 23 x Line 4 /12
25	**Cost per Industrial Customer**	**$ 80,078**	Equals: Line 7 x Line 24

As Table 1 shows, the requested capacity charge will impose an overall average cost of $1,063 per DEO customer (line 3). The requested capacity charge is equivalent to a cost of $12.72/MWh (line 7). As a result, requested capacity charge will require the average DEO residential customer to pay an additional $433 (line 13), the average commercial customer to pay an additional $3,481 (line 19), and the average industrial customer to pay

[9] The total number of customers (line 2) does not tie to the sum of Residential, Commercial, and Industrial customers, because Public Street and Highway Lighting and Other Sales to Public Authorities are not included.

an additional $80,078 (line 25) in above-market costs to support DEO's legacy generating assets and the company's alleged "financial integrity."

Q. HOW MUCH WILL DEO CUSTOMERS PAY WHEN YOU INCLUDE THE $330 MILLION IN ESSC CHARGES THAT WILL BE COLLECTED TO PRESERVE THE COMPANY'S FINANCIAL INTEGRITY UNDER THE 2011 STIPULATION?

A. The totals for residential, commercial, and industrial customers are shown in Table 2. As this table shows, the combination of the ESSC and the requested capacity charge will mean the average customer will pay an additional $1,544 to support the financial integrity of DEO's legacy generating units. The average residential customer will pay an additional $629 (line 13), the average commercial customer will pay an additional $5,056 (line 19), and the average industrial customer will pay an additional $116,321 (line 25).

Table 2: Combined Customer Impacts of Requested Capacity Charge and ESSC[10]

Line No.	Line Item Description	Amount	Source / Calculation
1	Requested Capacity Charge + ESSC Charge	$ 1,059,122,082	Source: Exhibit WDW-1 Conf, Page 3 of 24 and Case No. 11-3549-EL-SSO, Exhibit WDW Supp 1
2	Average Number of Customers	685,859	Source: 2011 FERC Form 1, Page 304
3	**Total Capacity + ESSC Charge ($ per Customer)**	**$ 1,544.23**	Equals: Line 1 / Line 2
4	ESP Period (in months)	41	Source: Case No. 11-3549-EL-SSO, Exhibit WDW Supp 1
5	Annual MWh Sales	20,238,172	Source: 2011 FERC Form 1, Page 304
6	Total MWh Sales Over ESP Period	69,147,088	Equals: Line 4 x Line 5 /12
7	**Capacity Charge ($ per MWh)**	**$ 15.32**	Equals: Line 1 / Line 6
8	<u>Residential</u>		
9	2011 Residential Customers	610,416	Source: 2011 FERC Form 1, Page 301
10	2011 Residential Sales (MWh)	7,331,858	Source: 2011 FERC Form 1, Page 301
11	Residential Sales/Customer (MWh)	12.01	Equals: Line 10 / Line 9
12	Total Residential Sales/Cust ESP Charge Period	41.04	Equals: Line 11 x Line 4 /12
13	**Cost per Residential Customer**	**$ 629**	Equals: Line 7 x Line 12
14	<u>Commercial</u>		
15	2011 Commercial Customers	67,207	Source: 2011 FERC Form 1, Page 301
16	2011 Commercial Sales (MWh)	6,493,122	Source: 2011 FERC Form 1, Page 301
17	Commercial Sales/Customer (MWh)	96.61	Equals: Line 16 / Line 15
18	Total Commercial Sales Over ESP Period	330.10	Equals: Line 17 x Line 4 /12
19	**Cost per Commercial Customer**	**$ 5,056**	Equals: Line 7 x Line 18
20	<u>Industrial</u>		
21	2011 Industrial Customers	2,222	Source: 2011 FERC Form 1, Page 301
22	2011 Industrial Sales	4,938,881	Source: 2011 FERC Form 1, Page 301
23	Industrial Sales/Customer (MWh)	2,222.72	Equals: Line 22 / Line 21
24	Total Industrial Sales Over ESP Period	7,594.29	Equals: Line 23 x Line 4 /12
25	**Cost per Industrial Customer**	**$ 116,321**	Equals: Line 7 x Line 24

Q. WILL THESE SUBSIDIES OF DEO'S UNCOMPETITIVE GENERATION THAT ARE PAID BY DEO CUSTOMERS ADVERSELY AFFECT THE OHIO ECONOMY?

A. Absolutely. In total, DEO is asking its customers to pay over $1 billion of their money to support its uncompetitive legacy generating units. Although these funds will contribute to preserving the jobs of DEO (and AEP Ohio) employees who work at these plants, preserving those jobs will result in less economic growth in DEO's service territory and throughout Ohio.

10 The total number of customers (line 2) does not tie to the sum of Residential, Commercial, and Industrial customers, because Public Street and Highway Lighting and Other Sales to Public Authorities are not included.

In supporting the new capacity charge, DEO witness Trent states, "Access to low-cost, reliable power is a critical factor in a company's decision about where to locate its facilities."[11] I agree completely: DEO's requested capacity charge will drive away companies that are making location decisions. Companies will not be drawn to DEO's service territory by the prospect of having to pay many thousands of dollars more for their electricity; they will look elsewhere, possibly to other states.

III. RECALCULATION OF DEO CAPACITY COST ESTIMATES

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section, I present adjustments to the $729 million embedded cost of capacity value DEO requests from ratepayers on a nonbypassable basis by creating a regulatory asset. These changes address the following issues: (1) a recognition that, as part of the 2011 Stipulation, DEO was granted recovery of $330 million through a nonbypassable ESSC over the three-year period, 2012 – 2014; (2) incorporation of the impact of net income improvements identified in the deposition of witness Savoy; (3) reduction of the amount of General Plant allocated to power production to equal the amount allocated by DEO in its current electric distribution rate case[12]; (4) correction of the FZCP capacity prices used by DEO witness Wathen, which reflect the Base Residual Auction ("BRA") clearing prices for planning years 2012/13, 2013/14 and 2014/15, rather than the FZCP in 2012/13 and 2013/14 and the zonal price after the BRA and the first incremental auction price in 2014/15; and (5) adjustment of the above-market costs

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11 Trent Direct, p. 22, lines 15-16.

12 *In the Matter of the Application of Duke Energy Ohio, Inc. for an Increase in Electric Distribution Rates*, Case No. 12-1682-EL-AIR, filed June 7, 2012.

to account for structural separation of DEO's generating assets no later than December 31, 2014, as agreed to by DEO in the 2011 Stipulation.

Q. IN MAKING THESE REVISIONS TO DEO WITNESS WATHEN'S EMBEDDED COST ANALYSIS, ARE YOU TESTIFYING THAT DEO IS ENTITLED TO RECOVER ABOVE-MARKET CAPACITY COSTS?

A. No. As part of the 2011 Stipulation, DEO agreed to charge the PJM RPM market price to CRES providers to meet its FRR obligation. As DEO witness Wathen testified in support of the 2011 Stipulation, DEO agreed that its customers would not pay for capacity based on DEO's embedded costs of its legacy generating assets as proposed in its ESP Application but would instead "now be paying market-based prices for capacity <u>in perpetuity</u>."[13] DEO should plainly not be allowed to alter the terms of the 2011 Stipulation and recover the embedded costs of its legacy generating assets from its customers. Creating a regulatory asset that will "true up" the difference between DEO's estimate of its embedded capacity costs and the revenues the company will receive selling capacity at the market price will adversely affect retail competition because, once DEO begins to recover the regulatory asset, customers who shop will effectively be forced to pay twice for their capacity. These customers will pay the market price of capacity through their CRES providers and also pay for DEO's embedded capacity costs.

However, if the PUCO allows DEO to collect any above-market, embedded capacity costs, the amount the company is allowed to collect should be reduced significantly from the amount shown in Mr. Wathen's exhibits, based on the adjustments I present below.

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13 Wathen 2011 Supplemental, p. 10, lines 18-21 (emphasis added).

A. Reduction of the Regulatory Asset to Account for ESSC Revenues

Q. WHY SHOULD THE EMBEDDED CAPACITY COSTS DEO PROPOSES TO COLLECT BE REDUCED TO REFLECT THE ESSC PAYMENTS THE COMPANY IS RECEIVING?

A. As part of the 2011 Stipulation, DEO was authorized to collect $330 million from ratepayers through a nonbypassable ESSC, whose purpose was to provide for the financial integrity of the company's generating resources used to provide its FRR obligation. As DEO witness Wathen testified in support of the 2011 Stipulation,

> <u>The ESP further provides a degree of stability and certainty with respect to the financial integrity of Duke Energy Ohio for the term of the ESP</u> as the Company fulfills its commitment to legally separate its generation assets from the electric distribution utility (EDU) by transferring its generation fleet to a non-regulated affiliate.[14]

The plain language of Mr. Wathen's testimony in support of the 2011 Stipulation is clear: the ESSC represents additional revenues for DEO to support its legacy generating assets. The company's financial integrity as a provider of local distribution service is not threatened because DEO can, and has, filed electric and natural gas distribution rate cases, most recently in 2012. These traditional rate cases will provide the funds necessary for DEO to maintain distribution service and ensure it has access to capital markets.

Apparently, concerns about the financial integrity of DEO's legacy generating assets lie at the heart of DEO's application in the instant proceeding. DEO witness Savoy has prepared pro forma financial statements for DEO's generating assets that he proclaims "identify the significant financial harm to which DEO has been and will

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[14] Wathen 2011 Supplemental, p. 2, lines 7-11 (emphasis added).

continue to be exposed in the event its proposals, as described in these proceedings, are denied."[15] Similarly, DEO witness Trent states, "It is undeniable that Duke Energy Ohio's <u>financial integrity</u> is in a dire and precarious position. Duke Energy Ohio witness Brian Savoy testifies concerning the projected annualized return on equity (ROE) for Duke Energy Ohio's generating assets."[16]

Although, as I discuss below, Mr. Trent's testimony is incorrect – DEO's financial integrity is clearly <u>not</u> at risk and Mr. Savoy's return projections are erroneous – these witnesses' own testimony demonstrate that the entire purpose of the company's application for a regulatory asset is based on the same financial integrity issues discussed in the 2011 Stipulation and for which DEO was granted the right to collect $330 million through the nonbypassable ESSC. Moreover, according to the response to Interrogatory FES-3-5 (attached as Exhibit JAL-2), the ESSC revenues are entirely allocated to DEO's Commercial Power business segment, in which the company's legacy generating assets are accounted for. This affirms the fact that the ESSC revenues are designed to subsidize the legacy generating assets. If DEO requires additional revenues for its regulated distribution and transmission businesses, it can file a traditional rate case to request such revenues.

Q. HAS DEO ACCOUNTED FOR THE ESSC REVENUES IN THEIR PENDING ELECTRIC DISTRIBUTION CASE?

A. No. DEO did not include an offset to its requested revenue requirement in its pending electric distribution case for ESSC revenues. By not reflecting the ESSC

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15 *Application of the Duke Energy Ohio Company for the Establishment of a Charge Pursuant to Revised Code Section 4909.18*, Direct Testimony of Brian Savoy, March 1, 2013 ("Savoy Direct"), p. 5, lines 14-16.

16 Trent Direct, p. 11, lines 19-22 (emphasis added).

revenues in that case, DEO acknowledges that these revenues are not distribution-related and therefore are being used for the generation segment of their business.

Q. BECAUSE THE ESSC REVENUES ARE DESIGNED TO MAINTAIN DEO'S FINANCIAL INTEGRITY, WHAT IS THE MINIMUM ADJUSTMENT THE PUCO SHOULD MAKE TO DEO'S REQUEST?

A. If, despite the fact that creation of this new regulatory asset changes the terms of the 2011 Stipulation, leads to failure of the MRO v. ESP test, and allows DEO to continue recovering stranded generation costs years after the transition period ended, then <u>at an absolute minimum</u> the PUCO should reduce DEO's request for creation of a $729 million regulatory asset by the full $330 million the company will recover through the ESSC. This implies an absolute maximum regulatory asset value of $399,122,082, or $140,866,617 on an annualized basis.

B. Reduction of the Regulatory Asset to Account for Anticipated Net Income Improvements

Q. HOW SHOULD ANTICIPATED ADJUSTMENTS TO NET INCOME BE INCORPORATED AS AN ADJUSTMENT TO THE PROPOSED REVENUE REQUIREMENT?

A. Line 21 of Attachment BDS-1 refers to "Adjusted Net Income," which is calculated by subtracting current and deferred income taxes (line 20) from earnings before income tax ("EBIT") shown on line 19. On a before-tax basis, therefore, revenues must be "grossed-up" for income taxes, using DEO's effective marginal tax rate. For example, if after-tax income increases by $100 and the effective marginal tax rate is 35%, then pre-tax income increases by $100/(1 – 0.35) = $153.85. As a result, a $100 increase in after-tax net income reduces revenues to be collected by $153.85.

Q. WHAT IS THE OVERALL IMPACT ON NET REVENUE TO BE COLLECTED BECAUSE OF MR. SAVOY'S ANTICIPATED INCREASES IN AFTER-TAX NET INCOME IN 2013 AND 2014?

A. Using the effective 35.2796% effective income tax rate in Mr. Wathen's workpapers and the assumed midpoint increase in after-tax net income of **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]**, the overall reduction in revenues to be collected is **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]**.

Q. HAVE YOU CALCULATED THE IMPACT TO THE PROPOSED NET REVENUE TO BE COLLECTED SHOWN IN DEO WITNESS WATHEN'S ATTACHMENT WDW-1 FROM INCLUDING THE ESSC REVENUES AND ANTICIPATED INCREASES IN AFTER-TAX NET INCOME?

A. Yes. My calculation is shown in Table 3 below. Lines 1 – 12 of the table reproduce the values shown in Mr. Wathen's Attachment WDW-1. Line 13 subtracts the $330 million ESSC value, which is equivalent to $116,470,588 on an annualized basis over DEO's proposed 34-month recovery period, August 2012 – May 2015. Line 14 subtracts the **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]** associated with anticipated net income improvements discussed above. As a result, the total revenue to be collected is reduced from the $729,122,082 value to $229,160,126, or $80,880,044 on an annualized basis. Mr. Wathen's daily capacity rate of $224.15/MW-day is reduced to $115.75/MW-day. His net charge to be collected after accounting for revenues from capacity sales at the RPM market price is reduced from $158.08/MW-day to $49.69/MW-day.[17]

[17] The $/MW-day values are actually meaningless, and I report them in the table for comparison purposes only with Mr. Wathen's $/MW-day values.

**Table 3: Revised Wathen Capacity Cost Values,
Accounting for ESSC and Anticipated Net Income Improvements**

Line No.	Item	Total	Annualized	Notes
1	Total Revenue Requirement	$ 1,350,796,592	$ 476,751,738	Exh. WDW-1, p.3, Line 6
2	[redacted]			Exh. WDW-1, p.3, Line 7
3				Equals Line 1 + Line 2
4				Exh. WDW-1, p.3, Line 8
5				Exh. WDW-1, p.3, Line 10
6				Exh. WDW-1, p.3, Line 11
7	Net Revenue Requirement	$ 725,235,452	$ 255,965,454	Equals Σ { Lines 3, 4, 5, 6}
8	Commercial Activities Tax (0.26%)	$ 3,886,630	$ 1,371,752	Exh. WDW-1, p.3, Line 13
9	Net Revenue to be Collected	$ 729,122,082	$ 257,337,205	Equals Line 7 + Line 8
10	Wathen Capacity Rate (before-credits)		$ 323.26	Exh. WDW-1, p.1, Line 4/5
11	Wathen Capacity Rate (after energy, A/S-credits)		$ 224.15	Exh. WDW-1, p.1, Line 9/10
12	Wathen Capacity Rate (after cap, energy, A/S-credits)		$ 158.08	Exh. WDW-1, p.1, Line 14/15
13	Less ESSC Revenues	$ (330,000,000)	$ (116,470,588)	2011 Stipulation, annualized over 34 months
14	[redacted]			Savoy Depo., 3/15/2013, p.153, ($110M/(1-WDW-1,Page 15, Line 4))
15	**Net Revenue Requirement (less energy, A/S)**	**$ 533,854,604**	**$ 188,419,272**	Equals Σ { Lines 3, 5, 6, 8, 13, 14}
16	**Net Revenue to be Collected**	**$ 229,160,126**	**$ 80,880,044**	Equals Line 15 + Line 4
17	**Revised Wathen Capacity Rate (after energy, A/S-credits)**		**$ 115.75**	Equals Line 15 / 4,459.85 / 365
18	**Revised Wathen Capacity Rate (after cap, energy, A/S-credits)**		**$ 49.69**	Equals Line 16 / 4,459.85 / 365

C. Additional Adjustments for Capacity Prices and General Plant

Q. ARE THE ADJUSTMENTS IN TABLE 3 THE ONLY ADJUSTMENTS YOU RECOMMEND?

A. No. First, let me stress I recommend DEO not be allowed to create this regulatory asset whatsoever to recover any additional embedded costs associated with the legacy generating assets above revenues collected at the FZCP. If, however, the PUCO does allow DEO to establish this regulatory asset, Mr. Wathen's estimate also should be adjusted to (1) correct for incorrect FZCP prices he used to estimate capacity revenues and purchase costs; and (2) remove excess General Plant included in his rate base, and thus return on rate base and associated expenses and income taxes. These two changes also affect the amount of the Commercial Activities Tax to be collected.

Q. HOW DID YOU ADJUST THE CAPACITY PRICES?

A. Based on the data shown on DEO witness Wathen's work paper (attached as Confidential Exhibit JAL-3), the FZCP capacity prices used by DEO to estimate revenues from capacity sales and costs of capacity purchases are outdated and incorrect. Table 4 provides the current BRA and FZCP capacity prices.

Table 4: BRA and FZCP Capacity Prices

PJM Planning Year	RPM BRA Clearing Price ($/MW-day)	Final Zonal Capacity Price ($/MW-day)
	[1]	[2]
2012/13	$16.46	$16.74
2013/14	$27.73	$28.45
2014/15	$125.99	$128.17

Notes:
[1]: Source - PJM RPM Auction User Information, http://www.pjm.com/markets-and-operations/rpm
[2]: 2012/13 and 2013/14 are final RPM prices. 2014/15 reflects price after 1st incremental auction

Mr. Wathen's work papers show that he used the BRA clearing prices for the 2012/2013, 2013/14 and 2014/15 planning years, rather than the FZCP prices. The final "rest-of-PJM" or RTO RPM market price for the 2013/14 planning year, after the recent third incremental auction, is $28.45/MW-day.[18] For the 2014/15 planning year, PJM has conducted the Base Residual Auction and the first incremental auction. The current RTO market price for this planning year is $128.17/MW-day.[19]

[18] PJM, "2013 auction results for BRA and all incremental auctions.xls." Available at: http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2013-2014-auction-results-for-bra-and-all-incremental-auctions.ashx

[19] PJM, "2014/2015 First Incremental Auction Results.xls." Available at: http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2014-2015-first-incremental-auction-results.ashx

To adjust for revenues from the sale of capacity, I have used the data provided on the confidential work papers of DEO witness Wathen, which indicate DEO is currently selling **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]** of capacity in the current 2012/13 planning year, and will be selling **[BEGIN CONFIDENTIAL]** [redacted]**[END CONFIDENTIAL]** of capacity in the 2013/14 and 2014/15 PJM planning years, respectively. Using these values and the prices shown in Table 4, the resulting capacity sales revenues total **[BEGIN CONFIDENTIAL]** [redacted]**[END CONFIDENTIAL]** value used by Mr. Wathen. I also adjusted the capacity purchase costs to reflect the current capacity prices shown in Table 4. Using these values and the prices shown in Table 4, the resulting capacity purchase expenses total **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]** value used by Mr. Wathen.

Q. WHY DID YOU ADJUST THE AMOUNT OF GENERAL PLANT REFLECTED IN DEO WITNESS WATHEN'S ATTACHMENT WDW-1?

A. As shown on page 13, line 15 of Attachment WDW-1, DEO witness Wathen allocated 51.417% of total DEO Electric General Plant to the legacy generating assets. His allocation percentage is based on wages and salaries related to electric production operations as a percentage of total electric operations wages and salaries, excluding administrative and general labor expense, as shown on page 13 of 24, lines 13 and 15 of Exhibit WDW-1. Of that 51.417% value, Mr. Wathen allocates 32.147% to demand-related (fixed) costs and the remaining 19.270% to energy (variable) costs of production.

This allocation is inconsistent with the allocation of General Plant in DEO's current electric distribution rate case, Case No. 12-1682-EL-AIR.

Q. WHAT IS GENERAL PLANT?

A. Under FERC's Uniform System of Accounts, General Plant consists of assets that provide service to all aspects of the company that cannot be otherwise categorized. For example, Account 390, Structures, includes the offices used by DEO shared-services employees – accountants, planners, human resources managers, and so forth. Those offices are used to support not only the generation function, but also the distribution, transmission, and customer functions. Because General Plant is used for all of these functions, it must be allocated among them for ratemaking purposes.

Q. HOW DID YOU ADJUST MR. WATHEN'S GENERAL PLANT PERCENTAGE?

A. In DEO's current Electric Distribution case, DEO allocates 92.257% of all Electric General Plant to the Ohio distribution part of its business, as shown on Schedule B-2.1 of that filing (attached as Exhibit JAL-4). Because, in that proceeding, DEO is including 92.257% of the total company Electric General Plant in the Ohio jurisdictional distribution rate base, then it is impossible to allocate more than 7.743% of company Electric General Plant to the Ohio electric production rate base DEO witness Wathen is defining for purposes of this capacity proceeding (100% - 92.257% = 7.743%). Moreover, the 7.743% value is possible only if zero percent of Electric General Plant is allocated to the transmission function. Thus, using any higher percentage would allow DEO to recover the same Electric General Plant costs in <u>both</u> its distribution rates and through the requested regulatory asset, which is clearly incompatible with basic rate regulation.

Therefore, I adjusted the Electric General Plant allocator to its maximum level of 7.743% to avoid double recovery of Electric General Plant in both distribution and production rate base. I then used the same relative allocation percentages between demand-related (fixed) and energy (variable) costs. Thus, of the 7.743% of Electric General Plant allocated to production, I allocated 4.841% to demand-related costs and 2.902% to energy-related costs. I applied these same allocation percentages to the Intangible Plant balances shown on page 13, line 4 of Attachment WDW-1. The result reduces Mr. Wathen's Electric General Plant allocated to the legacy generating assets from $46,414,290 to $4,370,094, and Intangible Plant allocated to the legacy generating assets from $40,379,600 to $3,801,903. Thus, I reduced Mr. Wathen's overall allocation of Electric General Plant and Intangible Plant from the $54,265,855 he uses, as shown on page 13, line 16 of Attachment WDW-1 to $8,171,997, which reduces his Total Revenue Requirement by $25,676,839.

Q. WHAT IS THE IMPACT OF ALL THE ADDITIONAL CHANGES YOU DISCUSSED?

A. Collectively, these changes reduce the amount of Mr. Wathen's total claimed revenue to be collected from $729,122,082 to $200,447,690, or $70,746,244 on an annualized basis, as shown in Table 5. This implies a capacity rate of $110.74/MW-day net of energy and ancillary service credits, and a rate of $43.46/MW-day net of capacity sales revenues.

Table 5: Revised Wathen Capacity Cost Values, All Adjustments

Line No.	Item	Total	Annualized	Notes
1	Total Revenue Requirement	$ 1,325,186,513	$ 467,712,887	Exh. WDW-1, p.3, Line 6, adj. for General Plant
2	[redacted]			Exh. WDW-1, p.3, Line 7, adj. for RPM cost
3				Equals Line 1 + Line 2
4				Savoy WP, p. 78 and final FZCP prices, per Table 4
5				Exh. WDW-1, p.3, Line 10
6				Exh. WDW-1, p.3, Line 11
7	Net Revenue Requirement	$ 696,583,023	$ 245,852,832	Equals Σ { Lines 3, 4, 5, 6}
8	Commercial Activities Tax (0.26%)	$ 3,826,622	$ 1,350,572	Equals Line 3 x [(1/0.9974) - 1]
9	Less ESSC Revenue	$ (330,000,000)	$ (116,470,588)	2011 Stipulation, annualized over 34 month period
10	[redacted]			Savoy Deposition, 3/15/2013, p.153, ($110M/(1-WDW-1,Page 15, Line 4))
11	**Net Revenue Requirement (less energy, A/S)**	$ 510,774,755	$ 180,273,443	Equals Σ { Lines 3, 5, 6, 8, 9,10}
12	**Net Revenue to be Collected**	**$ 200,447,690**	**$ 70,746,244**	Equals Line 10 + Line 4
13	**Revised Wathen Capacity Rate (after energy, A/S-credits)**		**$ 110.74**	Equals Line 10 / 4,459.85 / 365
14	**Revised Wathen Capacity Rate (after cap, energy, A/S-credits)**		**$ 43.46**	Equals Line 11 / 4,459.85 / 365

D. <u>Adjustment to Account for Structural Separation of DEO's Generating Assets</u>

Q. WHY DOES STRUCTURAL SEPARATION OF DEO'S GENERATING ASSETS BY DECEMBER 31, 2014 REQUIRE AN ADJUSTMENT TO MR. WATHEN'S EMBEDDED CAPACITY COST ESTIMATES?

A. After structural separation, DEO's new affiliated Genco will be a separate corporate entity selling wholesale energy and capacity. As such, it will be regulated by FERC, which oversees the PJM energy and capacity markets. The new Genco will operate like other competitive generation suppliers. Because DEO will still be a FRR entity, it will have to purchase all of its capacity from the PJM market as of January 1, 2015 through bilateral transactions. (As a FRR entity, DEO cannot participate in the PJM RPM auctions.)

The Genco, which will operate independently from DEO, will be unable to force DEO to enter into a contract to purchase capacity at an above-market, fully embedded cost price. FERC will not allow such a contract to be enforced, because it would be a clear cross-subsidy by regulated ratepayers to the Genco. Nor, for that matter, will the PUCO be able to mandate that DEO purchase capacity from the Genco at the above-market, fully embedded cost, again, because FERC will have jurisdiction over such a wholesale transaction. And, if it could mandate such a contract, the PUCO would be forcing DEO to incur an imprudent cost.

Q. HOW DOES THIS AFFECT MR. WATHEN'S CALCULATION OF THE REGULATORY ASSET VALUE?

A. Structural separation means that all above-market, embedded capacity costs incurred as of January 1, 2015 should be eliminated from Mr. Wathen's calculations.

Q. HAVE YOU MADE THOSE ADJUSTMENTS?

A. Yes. The adjusted costs are shown in Table 6.

Table 6: Revised Wathen Capacity Cost Values, Adjusted for Structural Separation

Line No.	Item	Total	Annualized	Notes
1	Total Revenue Requirement	$ 1,130,306,144	$ 467,712,887	Exh. WDW-1, p.3, Line 6, adj. for General Plant and last 5 months of PY 15
2	[redacted]			Exh. WDW-1, p.3, Line 7, adj. for RPM cost and last 5 months of PY 15
3				Equals Line 1 + Line 2
4				Savoy WP, p. 78 and final FZCP prices, per Table 4 and adj. for last 5 months of PY 15
5				Exh. WDW-1, p.3, Line 10, adj. per Savoy depo. and adj. for last 5 months of PY 15
6				Exh. WDW-1, p.3, Line 11 adj. for last 5 months of PY 15
7	Net Revenue Requirement	$ 621,218,406	$ 257,055,892	Equals Σ { Lines 3, 4, 5, 6}
8	Commercial Activities Tax (0.26%)	$ 3,198,948	$ 1,323,703	Equals Line 3 x [(1/0.9974) - 1]
9	Net Revenue to be Collected	$ 624,417,355	$ 258,379,595	Equals Line 7 + Line 8
10	Less ESSC Revenue	$ (330,000,000)	$ (136,551,724)	2011 Stipulation, annualized over 29 month period
11	[redacted]			Savoy Deposition, 3/15/2013, p.153, ($110M/(1-WDW-1,Page 15, Line 4))
12	**Net Revenue Requirement (less energy, A/S)**	$ 337,161,971	$ 139,515,298	Equals Σ { Lines 3, 5, 6, 8, 10,11}
13	**Net Revenue to be Collected**	**$ 124,455,400**	**$ 51,498,786**	Equals Line 11 + Line 4
14	**Revised Wathen Capacity Rate (after energy, A/S-credits)**		**$ 85.71**	Equals Line 11 / 4459.85 / 365
15	**Revised Wathen Capacity Rate (after cap, energy, A/S-credits)**		**$ 31.64**	Equals Line 12 / 4459.85 / 365

As Table 6 shows, eliminating the five months of 2015 from the calculation further reduces the net revenue amount to $124,455,400.

Q. CAN YOU SUMMARIZE THE OVERALL IMPACT OF YOUR ADJUSTMENTS TO MR. WATHEN'S CALACULATED REVENUE TO BE COLLECTED?

A. Yes. Table 7 summarizes the adjustments I have made to Mr. Wathen's revenue to be collected amount of $729,122,082 to the $124,455,400 in Table 6.

Table 7: Summary of Adjustments to Wathen Revenues to be Collected

Line No.	Item	Total
1	Net Revenue to be Collected -As Filed	$ 729,122,082
2	Adjustment 1 - ESSC Revenue	$ (330,000,000)
3	[redacted]	
4	Adjustment 3 - General Plant grossed up for CAT	$ (25,676,839)
5	[redacted]	
6		
7	Net Revenue to be Collected -Adjusted	$ 124,455,400

IV. THE PROPOSED CAPACITY CHARGE LEADS TO FAILURE OF THE ESP V. MRO TEST THE COMPANY SUBMITTED TO JUSTIFY ACCEPTANCE OF THE STIPULATION

Q. WHY IS THE ESP V. MRO TEST IMPORTANT?

A. R.C. 4928.143(C)(1) states that an electric security plan must be "[m]ore favorable in the aggregate as compared to the expected results that would otherwise apply under section 4928.142 of the Revised Code." One common interpretation of this requirement is to compare the present value costs paid by ratepayers under a proposed ESP with the present value costs those ratepayers would otherwise pay under a market rate offer ("MRO"), i.e., a comparison to market-based rates. This, in fact, is the analysis DEO witness Wathen himself performed in support of the 2011 Stipulation, as presented in his Attachment WDW Supp-1 (attached as Exhibit JAL-5). Mr. Wathen's performance of this "better in the aggregate test" showed a net present value ("NPV") benefit of $62,059,459 for the stipulated ESP compared to an MRO.

Because DEO proposes to collect an additional $729 million in revenues and create a regulatory asset, the terms of the stipulated ESP have changed. As such, a new ESP v. MRO test is required. As I show below, updating Mr. Wathen's own "better in the aggregate test" reveals the new ESP fails the "better in the aggregate test" when the new revenues DEO proposes to collect are included.

Q. DEO ARGUES THE TERMS OF THE ESP ARE NOT CHANGING, BUT THAT DEO IS SIMPLY SEEKING TO RECOVER THE COSTS ASSOCIATED WITH "NONCOMPETITIVE WHOLESALE CAPACITY SERVICE."[20] DO YOU AGREE?

A. No. Irrespective of the self-serving arguments made by DEO, the company wishes to recover higher capacity costs than set forth in the 2011 Stipulation and to establish a regulatory asset that will be recovered from all of its ratepayers on a nonbypassable basis. This is no different than what AEP Ohio initially requested as part of its SSO filing, which was to charge all customers an embedded cost-based capacity charge.

DEO's argument that capacity is a noncompetitive wholesale service also makes no economic sense. In PJM, there is a competitive wholesale capacity market, which is overseen by the Federal Energy Regulatory Commission ("FERC"). DEO voluntarily joined PJM and now wants to recover capacity costs that it could not otherwise recover on a competitive basis in the PJM market.

Q. DEO CITES THE COMMISSION DECISION ALLOWING AEP OHIO TO CHARGE AN EMBEDDED COST-BASED CAPACITY RATE TO CRES PROVIDERS AS THE REASON FOR ITS APPLICATION IN THIS PROCEEDING. IS DEO'S PROPOSAL TO COLLECT AN EMBEDDED-COST BASED RATE THE SAME AS AEP OHIO?

A. No. DEO is not proposing to charge CRES providers an above-market capacity price, as AEP Ohio did in Case No. 10-2929-EL-UNC. The PUCO ordered AEP Ohio to

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[20] Trent Direct, p. 5, line 13.

collect these revenues on a deferred basis, establishing a regulatory asset. However, the plain language of the PUCO Order in Case No. 10-2929-EL-UNC is that the deferred revenues are based on capacity sold to CRES providers. In contrast, DEO wishes to establish a regulatory asset for all of its above-market embedded capacity costs, and not just the costs associated with capacity resources the company provides to CRES providers under its FRR obligation.

Q. WHY DID DEO DECIDE TO WITHDRAW FROM MISO AND JOIN PJM?

A. In Case No. 10-2586-EL-SSO, in which DEO applied for a MRO, DEO witness Kenneth Jennings set out four reasons for DEO's decision to withdraw from MISO and join PJM.[21] In addition to discussing how joining PJM would eliminate the "tying" of jointly owned generating units between MISO and PJM, and that DEO's joining PJM would mean the PUCO would only need to monitor PJM RTO rules,[22] Mr. Jennings raised two issues specifically related to the PJM capacity market.

> PJM's forward-looking capacity market provides a useful tool for utilities and suppliers in determining pricing going forward and offers a measure of predictability for resource planning. Finally, as explained by Duke Energy Ohio witness Julia S. Janson, competition has arrived and is working in Duke Energy Ohio's service territory. The PJM market is a better fit for competitive retail electric markets for the reasons I already described, and those below regarding membership of other utilities and forward-looking capacity markets with prices determined through transparent auctions.[23]

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21 *In the Matter of the Application of Duke Energy Ohio for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Accounting Modifications, and Tariffs for Generation Service*, Case No. 10-2586-EL-SSO, Direct Testimony of Kenneth J. Jennings, November 15, 2010 ("Jennings 2010 Direct").

22 Jennings Direct, p. 7, line 11 – p. 8, line 10.

23 *Id.*, p. 8, lines 11-19.

Q. DID MR. JENNINGS INDICATE THE CAPACITY PRICE DEO WOULD CHARGE UNDER ITS FRR OBLIGATION?

A. Yes. In his testimony, Mr. Jennings stated:

> Duke Energy Ohio, as FERC has approved, will serve all load at the RPM Price, as provided for in Section D.8 of Schedule 8.1, except for, of course, those alternative retail load serving entities that choose to self supply. <u>To be consistent with the capacity price paid by other load within the PJM region, the price paid by wholesale load under the Out of Time FRR plan will be the Final Zonal Capacity Price for unconstrained portions of the PJM region</u>.[24]

Mr. Jennings's testimony is quite clear that DEO intended to charge its customers the RPM market price for capacity. Moreover, the 2011 Stipulation reflects that fact. Now, however, DEO seeks to collect from all of its customers, both those who shop and those who take SSO service, an above-market, embedded cost-based capacity price by accruing $729 million in additional monies for its capacity in a regulatory asset, and then collecting that amount from all customers through a nonbypassable charge.

Q. WHY ARE MR. JENNINGS'S STATEMENTS FROM NOVEMBER 2010 RELEVANT TODAY?

A. From an economic perspective, Mr. Jennings's (and DEO's) position in November 2010 and the 2011 Stipulation almost one year later provided a clear economic signal to CRES providers. As a FRR entity, DEO was clearly affirming it would provide all capacity required, including capacity required by CRES providers, at the PJM RPM market price. CRES providers would therefore have no economic incentive to opt-out and obtain their own capacity supplies in the PJM market.

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[24] *Id.*, p. 15, lines 10-15 (emphasis added).

Now, DEO wishes to recover its full embedded capacity cost for capacity by establishing a regulatory asset. Although DEO argues doing so will have no impact on retail competition,[25] this is untrue. There are two reasons for this. First, the additional generation revenues DEO is requesting could provide a cross-subsidy to DEO's retail affiliate, which can then undercut other CRES providers. Second, the additional revenues will enhance the economic value of generating assets when DEO structurally separates its generating assets by the end of 2014. An analogy is obtaining a mortgage on a "fixer-upper" home. Collecting the additional revenues allows DEO to improve the "fixed-upper" nature of its legacy generating assets, which will then have greater market value when transferred to the new Genco, just like a repaired "fixer-upper" home. The capacity charge subsidizes the future Genco's provision of competitive retail electric service.

A. <u>With the Proposed New Capacity Charge, the DEO ESP fails the "Better in the Aggregate Test."</u>

Q. HAS DEO PROVIDED AN UPDATED "BETTER IN THE AGGREGATE" TEST AS PART OF ITS TESTIMONY IN THIS PROCEEDING?

A. No. This is an important omission, because DEO is proposing to unilaterally change its ESP by creating a new Rider DR-CO that will create a regulatory asset associated with its embedded capacity costs. Because DEO has proposed to change the terms of the 2011 Stipulation through the addition of this new rider, it is reasonable to assume the company should provide an updated ESP v. MRO test.

Q. HOW WILL THIS NEW RIDER AFFECT THE ESP V. MRO TEST?

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[25] Trent Direct, pp. 26-27.

A. The new rider will add $729 million in deferred costs to the ESP. Thus, it should be added to the ESP side of the test ledger.

Q. BUT SHOULDN'T THAT COST ALSO BE ADDED TO THE MRO SIDE OF THE TEST, TOO?

A. No. The MRO is supposed to reflect the market alternative. Therefore, the MRO should reflect the same costs as its MRO did in DEO witness Wathen's 2011 Supplemental testimony[26] in support of the Stipulation, because the equivalent MRO is not changing.

Q. DID MR. WATHEN INCLUDE THE $330 MILLION IN ESSC REVENUES ON THE MRO SIDE OF THE TEST?

A. No. In support of the 2011 Stipulation, DEO witness Wathen prepared an ESP v. MRO test (previously attached as Exhibit JAL-3). In that test, Mr. Wathen correctly included the ESSC charges on the ESP side of the test, but <u>not</u> on the MRO side.

It makes no sense to include the $330 million in revenues DEO will collect under the ESSC to maintain DEO's financial integrity on the ESP side with no offsetting cost under the MRO, while not using the same treatment for the $729 million in additional costs DEO now claims it needs to maintain the company's financial integrity when, as I discussed previously, DEO's claimed purpose of the new regulatory asset is exactly the same as that for the ESSC.

If DEO wished to modify the existing ESSC to collect an additional $729 million needed to maintain its financial integrity, then those costs clearly would be excluded from

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[26] Wathen 2011 Supplemental, Attachment WDW Supp-1.

the MRO side of the "better in the aggregate" test because those costs are above market, by definition. Moreover, it would be disingenuous for DEO, having justified the stipulated ESP based on its own ESP v. MRO test, to now claim the test is unaffected because the above-market capacity costs should be reflected on both the ESP and MRO sides of the test.

Q. IN THE AEP OHIO ESP CASE NO. 11-346-EL-SSO, WAS AEP OHIO'S RETAIL STABILITY RIDER INCORPORATED ON THE MRO SIDE OF THE ESP V. MRO TEST?

A. No. In Case No. 11-346-EL-SSO, the PUCO determined that the costs of AEP Ohio's "Retail Stability Rider" ("RSR"), which is functionally equivalent to DEO's existing ESSC, were to be included on the ESP side of the ESP v. MRO test comparison with no offsetting cost under the MRO.[27] DEO testifies that the increase in the capacity charge is for the same purpose as its existing ESSC: to preserve the financial integrity of the company. As such, it is proper to exclude the higher capacity costs from the MRO side of the ESP v. MRO test.

Q. HAVE YOU PREPARED AN UPDATED ESP V. MRO TEST INCORPORATING DEO'S PROPOSED $729 MILLION REGULATORY ASSET CHARGE FOR FINANCIAL INTEGRITY?

A. Yes. Table 8 reproduces Exhibit WDW Supp-1, adding in the $729,122,082 of additional costs DEO proposes to collect (line 6') on a per-MWh basis. As Table 8

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[27] *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan, Case No. 11-346-EL-SSO, et al*., Opinion and Order, August 8, 2012 ("AEP SSO Order"), p. 75.

shows, the proposed regulatory asset adds on average, over $10/MWh to the ESP charge over the term of the ESP.

Table 8: Revised ESP v. MRO Test

Duke Energy Ohio					
Present Value Benefit of ESP Compared to MRO [a]					
Line		**Jan '12-Dec '12**	**Jan '13-Dec '13**	**Jan '14-Dec '14**	**Jan '15-May '15**
	Price Forecasts				
1	Projected Legacy ESP Price [b]	$79.19	$74.45	$76.22	$75.44
2	Projected Retail Market Price [c]	$61.38	$66.31	$78.65	$89.00
3	MRO Blend % (of Market Price)	10%	20%	30%	40%
4	MRO Price Blended Rate ($/MWh)	**$77.41**	**$72.82**	**$76.95**	**$80.86**
5	Projected Retail Market Price (Line 2)	$61.38	$66.31	$78.65	$89.00
6	Electric Security Stabilization Charge [d]	5.37	5.29	5.19	-
6'	**Additional Proposed Capacity Revenues****	**$6.07**	**$14.02**	**$10.98**	**$9.31**
7	**Updated Proposed SSO Price in ESP**	**$72.82**	**$85.62**	**$94.83**	**$98.31**
	Revenue Comparison (MRO v. ESP)				
8	Total Revenue at MRO Rate	$1,584,804,517	$1,515,400,007	$1,629,570,849	$700,610,416
9	Total Revenue at ESP Rates				
10	**All kWh at Average ESP Rate**	**$1,490,831,855**	**$1,781,684,437**	**$2,008,226,098**	**$851,765,726**
11	Less: Discount for PIPP Load *(see workpaper)* [e]	(1,034,686)	(1,175,033)	(1,458,150)	(556,176)
12	**Updated Total Revenue at ESP Rates**	**$1,489,797,169**	**$1,780,509,404**	**$2,006,767,948**	**$851,209,550**
	Other Benefits of ESP (Per Stipulation) [f]				
13	Economic Development	$1,150,000	$0	$0	$0
14	Weatherization/Fuel Fund	1,700,000	-	-	-
15	Total Other Quantifiable Unconditional Benefits	$2,850,000	$0	$0	$0
16	Present Value [g] of MRO Revenue	$4,586,339,265			
17	**Updated Present Value [g] of ESP Revenue**	**$5,134,835,903**			
18	**Net Benefit of ESP to Customers (ESP v. MRO)**	**($548,496,638)**			
	Other Assumptions				
19	Projected Total Retail Sales (MWh) [h]	20,473,777	20,810,354	21,177,162	8,664,268
20	Projected Total PIPP Sales (MWh) [i]	297,409	302,298	307,627	125,860
Notes:	** Source: Wathen Attachment WDW-1				
	All other assumptions per WDW Supp-1, October 28, 2012				

The result is that the present value cost of the ESP over the 41-month period is $548.5 million larger than the present value of the corresponding MRO. Thus, DEO's proposal to collect an additional $729 million to support the "financial integrity" of its legacy generating assets results in failure of the ESP v. MRO test.

Q. WHAT ARE THE RESULTS OF THE ESP V. MRO TEST WITH ALL OF THE MODIFICATIONS YOU PRESENTED IN THE PREVIOUS SECTION OF YOUR TESTIMONY?

A. The results of the ESP v. MRO test with my modifications are shown in Table 9. As Table 9 shows, with modifications made to reflect a revenue requirement of $124,455,400, the ESP has a present value cost that is $43.9 million larger than the MRO. Thus, even with the modifications to Mr. Wathen's capacity cost estimates, DEO's proposal still fails the ESP v. MRO test.

Table 9: ESP v. MRO Test Results After Modifications to Wathen Costs

Duke Energy Ohio

Present Value Benefit of ESP Compared to MRO [a]

Line		Jan '12-Dec '12	Jan '13-Dec '13	Jan '14-Dec '14	Jan '15-May '15
	Price Forecasts				
1	Projected Legacy ESP Price [b]	$79.19	$74.45	$76.22	$75.44
2	Projected Retail Market Price [c]	$61.38	$66.31	$78.65	$89.00
3	MRO Blend % (of Market Price)	10%	20%	30%	40%
4	MRO Price Blended Rate ($/MWh)	**$77.41**	**$72.82**	**$76.95**	**$80.86**
5	Projected Retail Market Price (Line 2)	$61.38	$66.31	$78.65	$89.00
6	Electric Security Stabilitization Charge [d]	5.37	5.29	5.19	-
6'	**Additional Proposed Capacity Revenues****	**$0.50**	**$4.19**	**$1.27**	**$0.00**
7	**Updated Proposed SSO Price in ESP**	**$67.25**	**$75.79**	**$85.12**	**$89.00**
	Revenue Comparison (MRO v. ESP)				
8	Total Revenue at MRO Rate	$1,584,804,517	$1,515,400,007	$1,629,570,849	$700,610,416
9	Total Revenue at ESP Rates				
10	**All kWh at Average ESP Rate**	**$1,376,955,999**	**$1,577,115,531**	**$1,802,650,052**	**$771,119,852**
11	Less: Discount for PIPP Load *(see workpaper)* [e]	(1,034,686)	(1,175,033)	(1,458,150)	(556,176)
12	**Updated Total Revenue at ESP Rates**	**$1,375,921,313**	**$1,575,940,498**	**$1,801,191,902**	**$770,563,676**
	Other Benefits of ESP (Per Stipulation) [f]				
13	Economic Development	$1,150,000	$0	$0	$0
14	Weatherization/Fuel Fund	1,700,000	-	-	-
15	Total Other Quantifiable Unconditional Benefits	$2,850,000	$0	$0	$0
16	Present Value [g] of MRO Revenue	$4,586,339,265			
17	**Updated Present Value [g] of ESP Revenue**	**$4,630,223,357**			
18	**Net Benefit of ESP to Customers (ESP v. MRO)**	**($43,884,091)**			
	Other Assumptions				
19	Projected Total Retail Sales (MWh) [h]	20,473,777	20,810,354	21,177,162	8,664,268
20	Projected Total PIPP Sales (MWh) [i]	297,409	302,298	307,627	125,860

Notes: ** Source: FES Witness Lesser

All other assumptions per WDW Supp-1, October 28, 2012

V. BECAUSE DEO PREVIOUSLY AGREED TO FOREGO COLLECTION OF STRANDED COSTS AND TO RECOVER ITS GENERATION COSTS IN THE COMPETITIVE MARKETS, IT SHOULD NOT BE ALLOWED TO COLLECT ABOVE-MARKET CAPACITY COSTS.

Q. WHAT ARE STRANDED COSTS AND WHY ARE THEY RELEVANT TO DUKE ENERGY OHIO'S CAPACITY COST ESTIMATE?

A. Stranded costs are defined as the difference between the market value of an asset and its net undepreciated book value. For example, if a generating unit's market value is estimated at $500 million and its net book value is $600 million, then the unit has stranded costs of $100 million. Stranded costs are relevant to the capacity charge DEO proposes to charge all customers for two reasons. Stranded costs hinge on the net undepreciated book value of generating plant-in-service ("GPIS"). If the market value of a generating asset is greater than its net GPIS, then there are no stranded costs associated with that asset. Second, because, as discussed below, Revised Code Section 4928.01(A)(28) defined the starting date of competitive retail electric service as January 1, 2001, all generating plant investment subsequent to that date must be recovered from the market, rather than in cost-based rates. Thus, the only legitimate embedded capacity costs DEO could have recovered as stranded costs through a cost-based charge were those costs related to generating plant that was in service prior to the start of competitive retail service.

Q. WHY IS THE DATE OF JANUARY 1, 2001 RELEVANT TO DEO'S PROPOSAL TO USE ABOVE-MARKET CAPACITY PRICES?

A. S.B. 3 unbundled retail electric generation service from distribution and transmission service beginning January 1, 2001. When Ohio enacted S.B. 3, each electric utility was given an opportunity during a transition period to recover any previously-sunk costs in their generating facilities (*i.e*., costs incurred prior to the transition date of January 1, 2001) that would be uneconomic in competitive markets.[28] By definition, a utility could not incur stranded generation costs for investments made after the transition date, because all such generation investments would be recovered in the market.

Because S.B. 3 provided a clear demarcation date between pre-transition and post-transition generation costs, any cost-based capacity charges levied by DEO could apply only to generating plant that was in-service on or before December 31, 2000, the day before the transition date of January 1, 2001. However, as part of the stipulation in the Cincinnati Gas & Electric ("CG&E") ETP Proceeding, DEO waived recovery of all stranded generation costs. Thus, DEO's proposal in this proceeding – to recover all of its embedded capacity costs through a regulatory asset using a formula rate approach based on generating plant in service as of December 31, 2011 – is wrong for three reasons.

First, the transition period during which DEO was allowed to recover stranded generation costs is long over, and DEO is not entitled to any other cost-based recovery for those Legacy Generating Units.

Second, as I demonstrate below, DEO has already recovered all of its stranded generation costs.

Third, DEO includes in its capacity charges generating plant investment made by DEO between January 1, 2001 and December 31, 2011 – 11 years' worth of investment that, under S.B. 3, should be recovered only from market-based sales.

Q. HOW WERE STRANDED COSTS TO BE RECOVERED?

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[28] *In the Matter of the Applications of Cincinnati Gas & Electric Company for Approval of Their Electric Transition Plans and for Receipt of Transition Revenues*, Case No. 99-1658-EL-ETP, et al. ("CG&E ETP Proceeding").

A. Stranded cost recovery took two forms, which became known as Generation Transition Costs ("GTCs") and Regulatory Transition Costs ("RTCs"). An electric utility could recover GTCs through a transition charge during the transition period, provided the costs satisfied statutory requirements.[29] At the end of the transition period, which was December 31, 2005, unless modified by the Commission as part of a utility's transition plan, S.B. 3 stated that "the utility shall be fully on its own in the competitive market."[30] Similarly, an electric utility could recover its RTCs both during the transition period and for several years thereafter. For DEO, the transition period for recovering RTCs ended as of December 31, 2010.[31] Notably, amendments to R.C. 4928 in 2008 did <u>not</u> alter or limit these provisions.

DEO's ability to recover stranded costs of its generating facilities – meaning, any costs that would not be fully recovered through the competitive market after the transition period – ended over seven years ago for GTCs and over two years ago for RTCs.

The transition plan proceeding filed by DEO's predecessor, CG&E, reported that the Ohio jurisdictional share of the net book value of its generating assets, as of December 31, 2000, was approximately $1.353 billion.[32] And, in its transition plan

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29 R.C. 4928.39 provided for recovery of "just and reasonable transition costs of the utility, which costs the commission finds meet all of the following criteria:

(A) The costs were prudently incurred.

(B) The costs are legitimate, net, verifiable, and directly assignable or allocable to retail electric generation service provided to electric consumers in this state.

(C) The costs are unrecoverable in a competitive market.

(D) The utility would otherwise be entitled an opportunity to recover the costs."

30 R.C. 4928.38.

31 CG&E ETP Proceeding, Opinion and Order, August 31, 2000, at 6.

32 CG&E ETP Proceeding, Direct Testimony of John P. Steffen on Behalf of Cincinnati Gas & Electric Company, December 28, 1999, ("Steffen Direct"), Exhibit JPS-6, page 3. Mr. Steffen's exhibit shows an Ohio jurisdictional share value of 85.328%, which I have used in my analysis, as described below.

application, CG&E requested recovery of stranded generating costs from only two generating plants –Woodsdale and Zimmer.[33] CG&E estimated the stranded costs of those two units at $563 million.[34] CG&E also requested recovery of $364 million of generation-related regulatory assets.[35]

As part of the stipulation approved by the PUCO in that case, CG&E waived all recovery of the $563 million of stranded generation costs through GTCs or other equivalent revenues through any mechanism other than competitive market pricing.[36] CG&E also agreed that its opportunity to recover RTCs would end no later than December 31, 2010. Thus, CG&E, and hence, DEO, had committed to recover its sunk costs (as well as its variable costs) in the competitive market. Moreover, DEO reaffirmed that same commitment as part of the 2011 Stipulation, which called for DEO to charge CRES providers the PJM RPM market price for capacity and did not include any provision for recovering its legacy generating capacity's above-market embedded costs through a nonbypassable regulatory asset or any other means.

Q. HAS THE NET BOOK VALUE OF DEO'S LEGACY GENERATING UNITS DECREASED SINCE THE ETP PROCEEDING?

A. Yes. Ignoring the capital additions DEO has made to those units after the starting date of competitive retail electric service as January 1, 2001, which must be recovered in the market, the remaining undepreciated book value of the Legacy Generating Units has decreased over the ensuing 11 years.

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[33] CG&E ETP Proceeding, Application, December 28, 1999, p. 1.

[34] *Id.*

[35] *Id.*

[36] CG&E ETP Proceeding, Opinion and Order, August 31, 2000, at 5.

Q. WHY IS THIS RELEVANT?

A. Because stranded generation costs are defined as the difference between the market value of an asset (i.e., the net present value of future generation plant cash flows) and net undepreciated book value, these additional depreciation accruals represent a reduction in the initial estimates of DEO's Legacy Generation Unit's stranded generation costs. In other words, because the remaining undepreciated book value of pre-2001 generation plant investment necessarily decreases over time, so have any stranded costs.

Q. HOW DID YOU DETERMINE THE AMOUNT BY WHICH THE NET BOOK VALUE OF DEO'S LEGACY GENERATING UNITS DECREASED BETWEEN JANUARY 1, 2001 AND DECEMBER 31, 2011?

A. I began with the filings made by CG&E witnesses Steffen in the CG&E ETP Proceeding, using his estimate of the Ohio jurisdictional share of the net book value of CG&E's generating plants as of December 31, 2000. That value was $1,352,796,795. Next, I compared the list of generating plants for which Mr. Steffen had estimated net book value and eliminated the Woodsdale GT units 1-6, and the East Bend 2 coal-fired unit, which are not part of the legacy generating units. I subtracted Mr. Steffen's net book value estimates for these generating plants from his total, leaving a net GPIS value of $1,126,004,456, as of December 31, 2000.

Next, I used the annual depreciation amounts for the Legacy Generating Units. Specifically, using Mr. Steffen's data, I calculated the annual depreciation of the generating plants for the year 2000, removed the annual depreciation amounts for the Woodsdale and East Bend units, and multiplied the remaining value by 85.328%, the Ohio jurisdictional percentage shown in Mr. Steffen's testimony. The resulting annual depreciation amount equals $65,926,479. I then calculated the net book value of these units by applying the annual depreciation amount for the 12-year period, December 31, 2000 – December 31, 2012. This reduces the net undepreciated GPIS by $791,120,988 as shown in Table 10, line [7]. The resulting net undepreciated GPIS value for DEO's Legacy Generating Units is $334,883,468, as shown in Table 10, line [6].

Table 10: Reduction in Net Undepreciated GPIS of Legacy Generating Units Since 12/31/2000

Line No.	Item	Amount
[1]	Gross GPIS, 12/31/2000	$ 3,182,265,156
[2]	Net GPIS, 12/31/2000	$ 1,352,796,796
[3]	Less Net GPIS, Woodsdale Units 1-6, Eastbend Unit 2	$ 226,792,340
[4]	Net Ohio Jurisdictional Legacy Units, 12/31/2000	$ 1,126,004,456
[5]	Annual Depreciation, Ohio Jurisdiction Legacy Units, Year 2000	$ 65,926,749
[6]	Net GPIS, December 31, 2012	$ 334,883,468
[7]	**Reduction in Net GPIS, 1/1/2001-12/31/2012**	**$ 791,120,988**

NOTES:
[1] Source: CG&E ETP Application, Exhibit JPS-6, page 3
[2] Source: CG&E ETP Application, Exhibit JPS-6, page 3
[3] Source: CG&E ETP Application, Exhibit JPS-6, page 3
[4] Equals [2]-[3]
[5] Source: CG&E ETP Application, Exhibit JPS-6, page 2-3 and author caculation
[6] Equals [4]-12*[5]
[7] Equals [6]-[4]

Thus, over the 12-year period between December 31, 2000 and December 31, 2012, DEO accrued $791 million of additional depreciation expenses related to its Legacy Generating Units (ignoring all subsequent capital additions that would further add to the overall depreciation accrual). That $791 million in additional accrued depreciation represents a decrease in the stranded costs of the Legacy Generating Units.

Q. HAS DEO RECOVERED ALL OF ITS STRANDED GENERATION-RELATED COSTS ASSOCIATED WITH ITS LEGACY GENERATING UNITS?

A. Yes. Although DEO initially requested recovery of $563 million of stranded costs only for the Woodsdale and Zimmer generating plants, using CG&E witness Steffen's data, and the market values of CG&E's generating plants, as estimated by CG&E witness Pifer,[37] I estimate that the stranded costs associated with all of DEO's Legacy Generating Units were $396.94 million on 12/31/2000, as shown in Table 11.

Table 11: DEO Legacy Generating Units, Stranded Costs, 12/31/2000

Line No.	Item	Amount (1000$)
[1]	Market Value of CG&E Units, 12/31/2000	$1,074,365
[2]	Less Mkt. Value of East Bend and Woodsdale Units, 12/31/2000	$219,943
[3]	Net Market Value of "Legacy" Units	$854,422
[4]	Ohio Jurisdiction Share Percentage	85.328%
[5]	Net Ohio Jurisdiction Market Value of "Legacy" Units	$729,061
[6]	Net Undepreciated GPIS of Legacy Units, 12/31/2000	$1,126,004
[7]	**12/31/2000 Stranded Cost of Ohio Jurisdiction "Legacy" Units:**	**$396,943**

Notes:

[1] Source: Pifer, Exhibit HWP-5 WP.
[2] Source: Pifer, Exhibit HWP-5 WP.
[3] Equals [1] - [2].
[4] Source: Steffen, Exhibit JFS-6.
[5] Equals [3] x [4].
[6] Source: Steffen, Exhibit JFS-6, page 3.
[7] Equals [6] - [5].

Based on an overall estimate of $396.94 million of stranded generating costs as of December 31, 2000, and a reduction in depreciated value over the ensuing 12-year period of $791.12 million, DEO has long recovered all stranded costs from its Legacy Generating Units. Thus, it is appropriate for DEO to recover the remaining costs of those Legacy Generating Units only through competitive markets, based on market prices.

37 CG&E ETP Proceeding, Direct Testimony of Howard W. Pifer on Behalf of Cincinnati Gas & Electric Company, December 28, 1999 ("Pifer Direct"), Exhibit HWP-5, WP, p. 1.

Q. WHAT IS THE SIGNIFICANCE OF YOUR CONCLUSION THAT DEO HAS RECOVERED ALL OF THE STRANDED GENERATION COSTS ASSOCIATED WITH ITS LEGACY GENERATING UNITS?

A. In addition to the fact that DEO waived, and is thus not entitled to receive, any additional recovery of stranded generating costs, DEO has no basis for charging all customers an above-market price for capacity, or including an above-market price for capacity in its Competitive Benchmark Price, because DEO has recovered all of its stranded generation costs. Requiring all customers, including those who wish to purchase electricity from CRES providers, to pay DEO for all of its above-market capacity costs through creation of a regulatory asset and subsequent, nonbypassable charge, is not only contrary to Ohio's policy that those costs be at market, but will inappropriately result in double recovery of those costs.

Q. WHY IS IT IMPORTANT TO CONSIDER THE TREATMENT OF STRANDED COSTS?

A. By allowing utilities that should be structurally separated and be fully on their own in the competitive market, as envisioned under S.B. 3 and in R.C. 4928.38, to continue to be subsidized by all ratepayers, including those who wish to take service from CRES providers, the PUCO stifles electric competition and defeats one of the key purposes of restructuring: to create competitive markets in which generation owners have strong financial incentives to improve their operating efficiency, reduce costs, and make more informed economic decisions about their generating facilities.

In requesting a $729 million regulatory asset, on top of the $330 million the company is allowed to collect through the ESSC, DEO is simply taking over $1 billion from ratepayers to subsidize its generating assets today, so it can then compete against unsubsidized generators beginning in 2015. One wonders, however, if market conditions do not sufficiently improve in the next two years, whether DEO will apply to the PUCO for even more subsidies. Market competition cannot exist under such circumstances. Ultimately, Ohio ratepayers will pay higher costs for electricity and the Ohio economy will be harmed.

Q. DID DEO MAKE INVESTMENTS TO ITS LEGACY GENERATING ASSETS AFTER COMPETITION WAS UNDERWAY?

A. Yes. This is relevant to the balance sheet prepared by DEO witness Savoy in his Attachment BDS-2. Specifically, as discussed in the response to Interrogatory FES-2-15 and FES-2-16 (attached as Confidential Exhibit JAL-6), Mr. Savoy states he based his allocation of long-term debt to the legacy generating assets of **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]** on the pollution control bonds outstanding. However, as shown in the response to Interrogatory FES-2-21 (attached as Confidential Exhibit JAL-7), the total outstanding amount of pollution control bonds is just $402 million.[38]

In addition, the attachment to FES-2-48 (attached as Exhibit JAL-8) shows that, in the four-year period from 2009 to 2012, DEO spent over **[BEGIN CONFIDENTIAL]** [redacted]**[END CONFIDENTIAL]** on capital investments not related to pollution controls for the legacy generating plants. Again, there is no basis for allowing DEO to recover of these costs when the facilities were being operated as competitive power plants.

[38] The individual pollution control bonds listed in the response to Interrogatory FES-2-21 are also shown on pp. 256-257 of the DEO 2011 FERC Form-1 report (attached as Exhibit JAL-9).

Q. WHY DOES THE AMOUNT OF POLLUTION-CONTROL DEBT MATTER?

A. The discrepancy between the amount of long-term debt Mr. Savoy has attributed to the legacy generating assets, based on the methodology described in his response to Interrogatories FES-2-15 and 2-16, affects Attachments BDS-1 and BDS-2. Specifically, the "interest expense" amount on line 18 of Attachment BDS-1 must be reduced to account for the smaller amount of debt. As a result, I estimate the total interest expense over the 34-month period calculated by Mr. Savoy on line 18 of Attachment BDS-1 of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** a decrease of $34,723,241

Q. ARE THERE ANY OTHER REASONS WHY THE AMOUNT OF POLLUTION CONTROL BOND ISSUANCES MATTERS?

A. Yes. Only two of the pollution control bond issuances, Ohio Air Quality Development 1995 Series A and 1995 Series B, were issued prior to passage of S.B. 3, which restructured the Ohio electric industry. These two bonds have a total face value of $84 million, as shown on p. 256 of the DEO FERC Form-1 report. All of the $318 million of remaining pollution control bonds were issued after the advent of electric restructuring, when DEO knew it was required to structurally separate its generating assets from the regulated (called the U.S. Franchise Electric & Gas, or "USF&G") business. DEO made those investments with full knowledge that its legacy generating assets were to be structurally separated and after it had waived recovery of stranded generation costs. As a result, there is no economic basis for DEO to now claim that debt incurred to upgrade its legacy generating assets <u>after</u> restructuring should be guaranteed recovery through full recovery of those assets' embedded costs.

VI. DEO RATEPAYERS SHOULD NOT BE REQUIRED TO SUBSIDIZE DEO'S GENERATING ASSETS TO MAINTAIN THOSE ASSETS' "FINANCIAL INTEGRITY"

Q. HOW DO YOU DEFINE "FINANCIAL INTEGRITY?"

A. I define "financial integrity" as a company's ability to remain a "going concern." In other words, "financial integrity" means a company can meet its operating expenses, service its debt, be able to make needed capital investments and provide investors with an expected return that is comparable to the returns earned by firms facing comparable business and financial risks. This is how the U.S. Supreme Court defined financial integrity in its well-known *Hope Natural Gas* decision.[39]

Q. IN EVALUATING A COMPANY'S RETURN AND DETERMINING WHETHER IT MEETS THE "COMPARABLE RISK" REQUIREMENT OF HOPE, ARE THE RETURNS ON EACH INDIVIDUAL CAPITAL ASSET CALCULATED?

A. No. The analysis is done on an overall company basis. For example, DEO witness Vander Weide uses a discounted cash flow ("DCF") model to estimate projected equity returns of electric utilities and natural gas pipelines. He does not estimate a "risk-comparable" return on equity for individual assets or even specific business units.

Q. IN DISCUSSING THE CONSEQUENCES OF DENYING THE COMPANY ITS REQUESTED CAPACITY CHARGE REGULATORY ASSET, DOES DEO WITNESS TRENT ADDRESS DEO'S FINANCIAL INTEGRITY?[40]

A. No. First, Mr. Trent incorrectly implies DEO as a company will be forced to operate at a financial loss. As I discuss below, that is simply untrue. Second, Mr. Trent

[39] *Federal Power Comm'n. v Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("*Hope Natural Gas*"). "The return to the equity owner … should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital." *Id*. at 603.

[40] Trent Direct, pp. 21-25.

states that "the meaningful work that Duke Energy Ohio has done with regard to economic development and charitable contributions would need to be revisited."[41] Ironically, Mr. Trent also testifies that, "Access to low-cost, reliable power is a critical factor in a company's decision about where to locate its facilities."[42] Apparently, Mr. Trent believes that forcing businesses who wish to locate in DEO's service territory to pay higher electric costs because of the proposed nonbypassable charge that recover $729 million will enhance such businesses' access to "low-cost reliable power."

Q. IS A DECREASE IN CHARITABLE CONTRIBUTIONS AND WORK ON ECONOMIC DEVELOPMENT PROGRAMS EQUIVALENT TO A LOSS OF FINANCIAL INTEGRITY?

A. No.

Q. DOES IT MAKE SENSE TO ESTIMATE A RISK-COMPARABLE RETURN FOR AN INDIVIDUAL ASSET?

A. No. A firm's shareholders are concerned with overall return, based on all of the firm's business and financial risks, not the return on individual assets. For example, it makes little sense to ask, "What should be the return on DEO's bucket trucks?" or "What should be the return on a particular substation?" Yet, DEO witness Savoy's pro forma analysis shown in Attachments BDS-1 and BDS-2, and the resulting legacy generating asset equity returns shown in his Attachment BDS-3, does just this. He prepared a pro forma Income Statement and Balance Sheet for the legacy generating assets. This allows

[41] *Id.*, p. 25, lines 8-9.

[42] *Id.*, p. 22, lines 15-16.

him, and DEO, to present a biased picture of the company's overall financial health, which is what is most at issue.

Q. HAVE YOU REVIEWED DEO'S OVERALL INCOME STATEMENT AND BALANCE SHEET?

A. Yes. I have reviewed Duke Energy Corporation's 2012 10-K report, which was filed with the U.S. Securities and Exchange Commission on February 28, 2013, and provides statements of operations and comprehensive income, consolidated balance sheets, and statements of cash flows for each of its operating subsidiaries, including DEO. These are attached as JAL-10. In addition, I have reviewed the Business Segment data for the company, also reported in the 2012 10-K report, which is attached as Exhibit JAL-11.

Q. HOW HAS DEO'S OVERALL COMPREHENSIVE INCOME CHANGED SINCE 2010?

A. As shown on page 1 of Exhibit JAL-10, DEO had a comprehensive loss of $434 million in 2010, comprehensive income of $188 million in 2011, and comprehensive income of $202 million in 2012. The return on book equity for all of DEO in 2012 was 3.9%, an increase from the 2011 return on book equity of 3.6% and a negative return of -7.9% in 2010.[43] Moreover, the DEO statement of cash flows indicates that operating activities provided $444 million in cash in 2012. Thus, in DEO's first year as a member of PJM, its financial performance improved over the previous two years, when the company was part of MISO.

43 The negative return was the result of an $837 million impairment charge taken by DEO in 2010. Otherwise, DEO's comprehensive net income in that year would have been $403 million and its book return on equity would have been 7.4%.

Q. WHAT ARE DEO'S REPORTING BUSINESS SEGMENTS?

A. According to the 2012 10-K, DEO has two reportable operating segments: Franchised Electric and Gas, and Commercial Power. The legacy generating units fall under the Commercial Power segment. The legacy generating units are not a separate reporting business segment.

Q. DID THE COMMERCIAL POWER SEGMENT SUFFER A NET LOSS IN 2012?

A. No. In 2012, net income before income taxes (EBIT) for the Commercial Power segment was $75 million. This was slightly less than EBIT in 2011, which was $84 million. The decrease is attributable, in part, to decreases in wholesale energy and capacity prices.

Q. IS DEO UNABLE TO ACCESS CAPITAL?

A. No. According to the Duke Energy Corporation 2013 Analysts Meeting presentation, which was provided as part of DEO witness Savoy's deposition, DEO has access to $566 million in capital.

Q. MR. TRENT TESTIFIES THAT PROJECTED EQUITY RETURNS FOR DEO WILL BE BETWEEN -3.6% AND -13.5%?[44] DO YOU AGREE WITH THOSE PROJECTIONS?

A. No. DEO witness Savoy's Attachment BDS-3 is an estimate (and an incorrect and irrelevant one at that, as I discuss below) of the equity returns on DEO's legacy generating assets. It is <u>not</u> an estimate for <u>all</u> of DEO, which is the only meaningful basis for establishing whether DEO's financial integrity is impaired. The -13.5% return on

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[44] *Id.*, p. 24, lines 21-23. The equity return values referenced by Mr. Trent are found on line 4 of Attachment BDS-3.

equity value is Mr. Savoy's estimate for 2012. Yet, as I discussed above, DEO's overall return on book equity in 2012 was 3.9%. Moreover, as discussed previously, in his deposition Mr. Savoy stated that the company **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in net income on the legacy generating units for both 2013 and 2014.[45]

Q. DOES DEO HAVE AN INVESTMENT-GRADE CREDIT RATING AT THIS TIME?

A. Yes. DEO witness De May provides a summary of the company's different credit ratings by the different ratings agencies.[46] DEO's unsecured debt is rated between "BBB+" and "A-". The company's secured debt is "A" rated.

Q. ACCORDING TO MR. DE MAY, STANDARD & POOR'S ("S&P") ESTABLISHED A "NEGATIVE" OUTLOOK IN JULY 2012.[47] DOES THAT NEGATIVE OUTLOOK SOLELY APPLY TO DEO?

A. No. As Mr. De May states, that outlook applies to Duke Energy Corporation (the parent company) and all of its subsidiaries, not just DEO.[48] Moreover, both Moody's and Fitch assign "Stable" outlooks to DEO.

Q. DID S&P CITE DEO'S DETERIORATING "FINANCIAL INTEGRITY" AS THE REASON FOR ITS JULY 2012 RATINGS DOWNGRADE AND "NEGATIVE" OUTLOOK FOR DEO?

A. No. The S&P report, which is attached as Exhibit JAL-12, states:

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45 Savoy Confidential Deposition, 3/15/2013, pp. 153-54.

46 *Application of the Duke Energy Ohio Company for the Establishment of a Charge Pursuant to Revised Code Section 4909.18*, Direct Testimony of Stephen G. De May, March 1, 2013 ("De May Direct"), p. 7, line 20.

47 *Id.*, p. 8, lines 7-9.

48 *Id.*

> The ratings downgrade on Duke Energy and its subsidiaries stems from our view that abrupt leadership changes at the company have heightened regulatory risk in North Carolina and likely in Florida, significantly weakening the company's consolidated "excellent" business risk profile under our criteria. Our assessment of business risk incorporates the impact of the unexpected change in management on the company's regulatory relations (but not the actual change itself) and our view that the company may not be able to realize timely and constructive regulatory outcomes in North Carolina and Florida, two of its largest jurisdictions.[49]

This quote clearly states the reason for the downgrade and negative outlook stems from the sudden leadership changes at Duke Energy Corporation last year, and has nothing whatsoever to do with DEO's projected financial performance, let alone the financial performance of DEO's legacy generating units.

Q. DOES THE S&P REPORT YOU QUOTE FROM ABOVE DISCUSS HOW THE 2011 STIPULATION AFFECTED DEO'S FINANCIAL POSITION?

A. Yes. The report states, "The new ESP allows Duke Energy Ohio to collect $330 million over three years, which can help support the company's financial profile. As a result, Duke [Energy Ohio] has managed to restore its ability to earn a stable and fair return on the bulk of its Ohio assets at least through 2015."[50] Thus, contrary to DEO witness Trent's assertion regarding the "dire" financial situation faced by DEO, S&P states the company can earn a "stable and fair return on its Ohio assets at least through 2015."

Q. IS AN EXPECTATION THAT DEO WILL EARN A "STABLE AND FAIR RETURN" CONSISTENT WITH A LOSS OF FINANCIAL INTEGRITY?

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[49] S&P, "Duke Energy Corp. Rating Lowered To 'BBB+' From 'A-'; Progress Energy Inc. 'BBB+' Rating Affirmed; Outlook Is Negative," July 25, 2012 ("S&P Report"), p. 3.

[50] *Id.*, p. 6.

A. No. A company that is earning a "fair" and, thus, "risk-comparable" return is not losing its access to capital and, thus, its financial integrity is not threatened.

Q. DEO WITNESS SAVOY STATED HE DID NOT KNOW IF ANY RATINGS AGENCY PERSONNEL HAD SEEN HIS PRO FORMA ANALYSIS.[51] IF THE RATINGS AGENCIES WERE AWARE OF HIS ANALYSIS, WOULD THAT CHANGE THEIR OUTLOOK FOR DEO?

A. I doubt it, given all of the errors in his analysis, which I discuss in the next section. Ratings agencies base their ratings on multiple factors and perform their own, independent analyses. Moreover, ratings agencies are surely aware of this proceeding, and DEO's request for an additional $729 million, on top of the $330 million in ESSC revenues discussed in the previous quote from the S&P Report. Finally, ratings agencies (and investors) are concerned with the financial outlook of DEO as a whole, not just the company's legacy generating assets. The S&P Report is quite clear about its view of DEO's overall financial stability.

Q. IS DEO REQUIRED TO OPERATE ITS LEGACY GENERATING ASSETS AT A LOSS WHILE IT REMAINS A FRR ENTITY?

A. No. DEO can take several steps to improve the economics of its legacy generating assets. First, the company can determine whether it can improve the overall operating efficiency of the plants and reduce overall O&M costs. In fact, in his deposition, Mr. Savoy admitted this.[52] As a result, DEO's February 2013 financial forecast projects net income from the legacy generating assets to be **[BEGIN**

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51 Savoy Confidential Deposition, 3/15/2013, p. 140, lines 1-3.

52 *Id.*, p. 154, lines 11-24.

CONFIDENTIAL] [redacted] **[END CONFIDENTIAL]** in 2013 and 2014, than what is reflected in his Attachment BDS-1.[53]

Second, the company has the option of retiring or even "mothballing" some of its legacy generating plants, even those plants DEO jointly owns with AEP Ohio. DEO is already retiring the Beckjord units. Furthermore, in his deposition, Mr. Savoy also stated DEO has looked at selling the legacy generating assets.[54]

Q. AS A FRR ENTITY, IS DEO REQUIRED TO PROVIDE CAPACITY FOR ALL CUSTOMERS IN ITS SERVICE TERRITORY?

A. Yes. However, the FRR rule does <u>not</u> require the FRR entity to provide that capacity solely with its legacy generating assets. In fact, as DEO witness Wathen's work paper shows, the company will increase its capacity purchases in the 2013/14 and 2014/15 PJM planning years to meet its FRR obligation. And, after DEO structurally separates its generating resources, DEO will have the option of purchasing all of its FRR obligation at market.

Q. DEO WITNESS TRENT ARGUES THAT DEO'S FRR OBLIGATION IS A "NONCOMPETITIVE, WHOLESALE CAPACITY SERVICE."[55] DOES DEO HAVE AN OBLIGATION TO PROVIDE THAT SERVICE AT "LEAST-COST?"

A. Yes. In arguing that the provision of FRR capacity is providing a "noncompetitive, wholesale" service, DEO witness Trent also testifies that the Commission applies "traditional ratemaking principles"[56] to recovery of capacity costs.

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[53] *Id.*, p. 153, lines 8-19.

[54] *Id.*, p. 143, lines 21-22.

[55] Trent Direct, p. 3, line 20.

Q. ARE LEAST-COST PLANNING AND PRUDENCE ASPECTS OF "TRADITIONAL RATEMAKING PRINCIPLES?"

A. Yes. Thus, if, as Mr. Trent testifies, the PUCO can (and should) apply traditional ratemaking principles to recovery of capacity costs, then the PUCO can (and should) also evaluate the prudence of the costs incurred by DEO to meet its FRR obligation. Specifically, the PUCO can determine whether DEO is meeting its obligation in a least-cost and prudent manner.

Q. IS DEO'S USE OF ITS LEGACY GENERATING ASSETS THE "LEAST-COST" METHOD OF MEETING ITS FRR OBLIGATION?

A. No. DEO admits its legacy generating assets are much more costly than the market price. Mr. Wathen testifies that the embedded cost of DEO's legacy generating assets is $323.26/MW-day, which is far greater than the average PJM market price. Furthermore, DEO already purchases additional capacity in the market to meet its FRR obligation, and expects to increase those purchases from **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in the current planning year to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in the 2014/15 planning year.

DEO's reliance on its own legacy generating assets to provide FRR capacity is clearly not the least-cost alternative, because DEO assumes it can purchase capacity in the PJM market at a far lower price. Therefore, under traditional ratemaking principles, DEO's use of its legacy generating assets is imprudent and the company should not be allowed to recover its above-market embedded generation costs.

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[56] *Id.*, p. 13, line 16.

Q. IS THERE SUFFICIENT CAPACITY IN PJM FOR DEO TO RELY SOLELY ON CAPACITY FROM THE MARKET TO MEET ITS FRR OBLIGATION?

A. Yes. Over 8,100 MW of capacity that was offered into the BRA for the 2013/14 planning year did not clear. And, in the 2014/15 planning year, over 10,000 MW of capacity that was offered into the BRA did not clear.[57] Thus, DEO could have relied entirely on capacity that was offered into the RPM and not accepted, which would then have been available to DEO to be purchased bilaterally.

A. <u>DEO Witness Savoy's Pro Forma Analysis is Flawed and Unreasonable</u>

Q. DOES IT MAKE ECONOMIC AND FINANCIAL SENSE TO PRESENT PRO FORMA FINANCIAL STATEMENTS JUST FOR THE LEGACY GENERATING ASSETS?

A. No. As DEO's 2012 10-K report shows, Commercial Power is the reporting business segment. That segment has been profitable the last two years. If one accounts for the higher expected net income in 2013 and 2014 that Mr. Savoy discussed in his deposition,[58] as well as the ESSC revenues DEO is receiving, his work papers would show positive EBIT in both years.[59] In other words, the Commercial Power segment would be profitable. Because that business segment would be projected to earn a profit, there is no basis whatsoever for DEO's claim of a lack of financial integrity without the requested new charge.

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[57] *See*, PJM, "2014/2015 Base Residual Auction Results," May 13, 2011, p.17, Table 5. (Attached as Exhibit JAL-13).

[58] Savoy Confidential Deposition, 3/15/2013, p. 153, lines 8-19.

[59] In his work papers, Mr. Savoy shows EBIT of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. DOES DEO WITNESS SAVOY INCLUDE IN HIS PRO FORMA ANALYSIS ANY OF THE ESSC REVENUES THE COMPANY IS RECEIVING?

A. No. As I discussed previously regarding Mr. Wathen's embedded cost calculations, the $330 million in ESSC revenues were agreed to in the 2011 Stipulation to preserve DEO's financial integrity. Therefore, those revenues should be netted from any embedded cost calculations. Similarly, Mr. Savoy's pro forma analysis fails to account for any ESSC payments related to the legacy generating assets. This is one reason why his pro forma analysis has no probative value. Thus, operating income should be increased by $110 million in 2012, 2013, and 2014.[60]

Q. IN HIS DEPOSITION, WAS MR. SAVOY ASKED WHY HE DID NOT INCLUDE THE ESSC REVENUES?

A. Yes. Mr. Savoy stated, "The ESSC rider, as I understand it, was a charge to add stability to the utility for its move to market in January of 2012 and it's not directly tied to our generation assets."[61]

Q. DO YOU AGREE WITH MR. SAVOY'S UNDERSTANDING?

A. No. Mr. Savoy's understanding is plainly contradicted by DEO witness Wathen's statements in his testimony supporting the 2011 Stipulation,[62] as I discussed previously. The ESSC revenues were granted to enhance the "financial integrity" of DEO's legacy generating assets. Therefore, the ESSC revenues should be included in Mr. Savoy's pro forma financial statements.

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60 Although Mr. Savoy's attachment BDS-1 shows only the five-month period, August – December 2012, it is appropriate to include the entire $110 million of ESSC revenues in the revised net income calculations to reflect the annual return.

61 Savoy Deposition, 3/15/2013, p. 74, lines 14-17.

62 Wathen 2011 Supplemental, p. 2, lines 7-11.

Q. DOES DEO WITNESS SAVOY'S PRO FORMA ACCOUNT FOR THE [BEGIN CONFIDENTIAL][redacted][END CONFIDENTIAL] IN NET INCOME FOR 2013 AND 2014 IN THE FEBRUARY 2013 FINANCIAL FORECAST?

A. No. Thus, his 2013 and 2014 values should be increased commensurately.

Q. DOES DEO WITNESS SAVOY'S PRO FORMA ACCOUNT FOR THE ADDITIONAL CAPACITY REVENUES AND ENERGY MARGINS PROVIDED BY DEO'S NON-LEGACY GENERATING UNITS, INCLUDING HANGING ROCK, WASHINGTON, LEE, AND FAYETTE?

A. No. Moreover, in his deposition, DEO witness Savoy stated that inclusion of these plants in his pro forma would have improved net income.[63]

Q. DOES DEO WITNESS SAVOY'S TESTIMONY ACCURATELY REFLECT THE AMOUNT OF LONG-TERM DEBT?

A. No. As I discussed previously, Mr. Savoy stated that he allocated DEO's pollution control bonds to the legacy generating assets for purposes of preparing his pro forma analysis. The total face value of those bonds, as shown on p. 257 of DEO's 2011 FERC Form-1 report is $402 million. Yet, Mr. Savoy somehow allocated **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL]**, to the legacy generating assets, thus increasing the annual interest expense on his income statement by **[BEGIN CONFIDENTIAL]**[redacted]**[END CONFIDENTIAL].**

Q. WHAT IS THE TOTAL IMPACT OF THE ERRORS YOU IDENTIFIED IN MR. SAVOY'S ANALYSIS?

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63 Savoy Confidential Deposition, p. 110, line 1 – p.111, line 3.

A. The results of correcting the multiple errors in Mr. Savoy's analysis are shown in Confidential Exhibit JAL-14, which is a revised Attachment BDS-1. As this exhibit shows, rather than showing a net loss in 2013 and 2014, the legacy generating assets are profitable. And, as can be seen in the revised Attachment BDS-3, which is attached as Confidential Exhibit JAL-15, Mr. Savoy's return on book equity values in each year increase. Because 2012 is only a partial year, the 2012 ROE cannot be known for certain. However, just considering the last 5 months as provided by DEO, the recalculated return on book equity is 0.3%, rather than the -13.5% value shown in Attachment BDS-3. The values in 2013 and 2014 increase to 2.7% and 7.7%, respectively, rather than Mr. Savoy's -9.0% and -5.2% values in 2013 and 2014, respectively.

Q. DO THE REVISED NET INCOME AND RETURN ON BOOK EQUITY VALUES YOU CALCULATE INDICATE DEO WILL SUFFER A LOSS OF FINANCIAL INTEGRITY?

A. No. The fact that the revised calculations show positive and increasing net income between 2012 and 2014, and positive and increasing returns on book equity means that DEO will continue to have access to capital. There is no reasonable economic or financial basis for concluding otherwise. And, after structural separation takes place, DEO will be a traditionally regulated utility that can file rate cases to ensure it has adequate capitalization.

Q. WHY DID YOU NOT CALCULATE NET INCOME AND RETURN ON BOOK EQUITY VALUES FOR 2015, AS SHOWN IN MR. SAVOY'S EXHIBITS BDS-1 AND BDS-3, RESPECTIVELY?

A. The reason I did not calculate values for 2015 is because of structural separation that takes place on or before December 31, 2014. In 2015, the Genco will be required to function like any other competitive generating company in PJM. Therefore, whether it is profitable or not will be based on its own actions in the market, and thus these calculations are irrelevant.

Q. BASED ON THE ERRORS IN DEO WITNESS SAVOY'S PRO FORMA ANALYSIS, DO YOU CONSIDER IT TO HAVE ANY PROBATIVE VALUE IN THIS PROCEEDING?

A. No.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. However, I reserve the right to supplement my testimony as new information subsequently becomes available or in response to positions taken by other parties.

Jonathan A. Lesser, Ph.D.

President

SUMMARY OF EXPERIENCE

Dr. Jonathan Lesser is the President of Continental Economics, Inc., and has almost 30 years of experience working for regulated utilities, governments, and as an economic consultant. He has extensive experience in valuation and damages analysis, from estimating the damages associated with breaking commercial leases to valuing nuclear power plants. Dr. Lesser has performed due diligence studies for investment banks, testified on generating plant stranded costs, assessed damages in commercial litigation cases, and performed statistical analysis for class certification. He has also served as an arbiter in commercial damages proceedings.

He has analyzed economic and regulatory issues affecting the energy industry, including cost-benefit analysis of transmission, generation, and distribution investment, gas and electric utility structure and operations, generating asset valuation under uncertainty, mergers and acquisitions, cost allocation and rate design, resource investment decision strategies, utility financing and the cost of capital, depreciation, risk management, incentive regulation, economic impact studies of energy infrastructure development, and general regulatory policy.

Dr. Lesser has prepared expert testimony and reports in cases before utility commissions in numerous U.S. states; before the Federal Energy Regulatory Commission (FERC); before international regulators in Latin America and the Caribbean; in commercial litigation cases; and before legislative committees in Connecticut, Maryland, New Jersey, Ohio, Texas, Vermont, and Washington State. He has also served as an independent arbiter in disputes involving regulatory treatment of utilities and valuation of energy generation assets.

Dr. Lesser is the author of numerous academic and trade press articles. He is also the coauthor of *Environmental Economics and Policy*, published in 1997 by Addison Wesley Longman, *Fundamentals of Energy Regulation*, published in 2007 by Public Utilities Reports, Inc., and *Principles of Utility Corporate Finance*, published in 2011 by Public Utilities Reports, Inc. Dr. Lesser is also a contributing columnist and Editorial Board member for *Natural Gas & Electricity*.

AREAS OF EXPERTISE

- State, federal, and international electric rate regulation—cost of capital, depreciation, cost of service, cost allocation, pricing and rate design, incentive regulation, regulatory policy, wholesale and retail market design, and industry restructuring
- Commercial damages estimation and litigation
- Pipeline rate regulation
- Natural gas markets
- Cost-benefit analysis
- Economic impact analysis and input-output studies
- Environmental policy and analysis
- Market power analysis
- Load forecasting and energy market modeling
- Market valuation and due diligence
- Antitrust

SELECTED EXPERT TESTIMONY AND REPORTS

New York Association of Public Utilities

- ♦ FERC proceeding regarding formula transmission rate for Niagara Mohawk Power d/b/a National Grid (Docket No. EL12-101-000)

Subject: Allowed rate of return and capital structure.

Caribbean Utilities Company, Ltd.

- ♦ Rebuttal report on weighted average cost of capital methodology and recommendations for Caribbean Utilities Company, Ltd.

Utah Industrial Energy Users Coalition

- ♦ Proceeding before the Utah Public Service Commission (Case No. U-11035-200)

Subject: Appropriate methodology for embedded cost allocation for Rocky Mountain Power.

FirstEnergy Solutions Corp.

- Proceeding before the Ohio Public Utilities Commission (Case Nos. 12-426-EL-SSO)

  Subject: Dayton Power & Light Co., Electric Security Plan; financial integrity, anticompetitive cross-subsidization and need for structural separation

- Proceeding before the Michigan Public Service Commission (Case No. U-17032)

  Subject: Indiana & Michigan Power Co. proposed capacity charges for customers taking retail electric service.

- Proceeding before the Ohio Public Utilities Commission (Case Nos. 11-346-EL-SSO and 11-348-EL-SSO)

  Subject: Revised AEP Ohio energy security plan, benefits of retail market competition.

- Proceeding before the Ohio Public Utilities Commission (Case No. 10-2929-EL-UNC)

  Subject: Appropriate price for commercial retail electric suppliers to be charged by AEP Ohio for installed capacity under the PJM Fixed Resource Requirement tariff option.

Southwestern Electric Cooperative

- FERC proceeding regarding wholesale distribution rate application of Ameren Illinois (*Re: Midwestern ISO and Ameren Illinois*, Docket No. ER11-2777-002, et al.)

Subject: Allowed rate of return and capital structure

Exelon Corporation

- Proceeding before the New Jersey Board of Public Utilities (Docket No. EO-11050309)

Subject: PJM Capacity Market, Capacity Procurement, and Transmission Planning

Industrial Energy Users of Ohio

- Proceeding before the Ohio Public Utilities Commission (Case No. 08-917-EL-SSO)

  Subject: Determination of cost associated with "provider-of-last-resort" (POLR) service and AEP Ohio's use of option pricing models.

Southwest Gas Corporation

- FERC proceeding regarding rate application of El Paso Natural Gas Company (Docket No. RP10-1398-000)

  Subject: Development of risk-sharing methodology for unsubscribed and discount capacity costs.

Portland Natural Gas Shippers

- FERC rate proceeding regarding the rate application by Northern Border Pipeline Company (Re: Portland Natural Gas Transmission System, Docket No. RP10-729-000)

- FERC rate proceeding regarding the rate application by Northern Border Pipeline Company (Re: Portland Natural Gas Transmission System, Docket No. RP08-306-000)

  Subject: Natural gas supplies, economic lifetime, and depreciation rates.

Independent Power Producers of New York

- FERC proceeding (New York Independent System Operator, Inc., Docket No. ER11-2224-000)

  Subject: Reasonableness of the proposed installed capacity demand curves and cost of new entry values proposed by the New York Independent System Operator.

Maryland Public Service Commission

- Merger application of FirstEnergy Corporation and Allegheny Energy, Inc. (I/M/O FirstEnergy Corp and Allegheny Energy, Inc., Case No. 9233)

  Subject: Proposed merger between FirstEnergy Corporation and Allegheny Energy. Testimony described the structure and results of a cost-benefit analysis to determine whether the proposed merger met the state's positive benefits test, and included analysis of market power and merger synergies.

Alliance to Protect Nantucket Sound

- Proceeding before the Massachusetts Department of Public Utilities (Case No. D.P.U. 10-54)

  Subject: Approval of Proposed Long-Term Contracts for Renewable Energy With Cape Wind Associates, LLC.

Brookfield Energy Marketing, LLC

- FERC proceeding (*New England Power Generators Association, et al. v. ISO New England, Inc.,* Docket Nos. ER10-787-000, ER10-50-000, and EL10-57-000 (consolidated)).

  Subject: Proposed forward capacity market payments for imported capacity into ISO-NE.

Public Service Company of New Mexico

- Proceeding before the New Mexico Public Regulation Commission (Case No. 10-00086-UT)

  Subject: Load forecast for future test year, residential price elasticity study.

M-S-R Public Power Agency

- FERC proceeding (*Southern California Edison Co.*, Docket No. ER09-187-000 and ER10-160-000)

  Subject: Allowed rate of return for construction work in progress (CWIP) expenditures for certain transmission facilities.

- FERC proceeding (*Southern California Edison Co.*, Docket No. ER10-160-000)

  Subject: Allowed rate of return for construction work in progress (CWIP) expenditures for certain transmission facilities.

Financial Marketers

- FERC proceeding (*Black Oak Energy, LLC v PJM Interconnection, L.L.C.*, Docket No. EL08-014-002)

  Subject: Allocation of surplus transmission line losses under the PJM tariff.

Southwest Gas Corporation and Salt River Project

- FERC proceeding regarding rate application of El Paso Natural Gas Company (Docket No. RP08-426-000)

  Subject: Analysis of proposed capital structure and recommended capital structure adjustments

New York Regional Interconnect, Inc.

- Proceeding before the New York Public Service Commission (Case No. 06-T-0650)

  Subject: Analysis of economic and public policy benefits of a proposed high-voltage transmission line.

Occidental Chemical Corporation

- FERC Proceeding (*Westar Energy, Inc.* ER07-1344-000)

  Subject: Compliance of wholesale power sales agreement with FERC standards

EPIC Merchant Energy, LLC, et al.

- FERC Proceeding (*Ameren Services Company v. Midwest Independent System Operator, Inc.*, Docket Nos. EL07-86-000, EL07-88-000, EL07-92-000 (Consolidated)

  Subject: Allocation of revenue sufficiency guarantee costs.

Cottonwood Energy, LP

- Proceeding before the Public Utility Commission of Texas (*Application of Kelson Transmission Company, LLC for a Certificate of Convenience and Necessity for the Amended Proposed Canal to Deweyville 345 kV Transmission Line with Chambers, Hardin, Jasper, Jefferson, Liberty, Newton, and Orange Counties*, Docket No. 34611, SOAH Docket No. 473-08-3341)

  Subject: Benefits of transmission capacity investments.

Redbud Energy, LP

- Proceeding before the Oklahoma Corporation Commission (*Request of Public Service Company of Oklahoma for the Oklahoma Corporation Commission to Retain an Independent Evaluator,* Cause No. PUD 200700418)

  Subject: Reasonableness of PSO's 2008 RFP design.

The NRG Companies

- FERC Proceeding (*ISO New England Inc. and New England Power Pool,* Docket No. ER08-1209-000)

  Subject: Compensation of Rejected De-list Bids Under ISO-NE's Forward Capacity Market Design

Dynegy Power Marketing, LLC

- FERC proceeding, *KeySpan-Ravenswood, LLC v. New York Independent System Operator, Inc.*, Docket No. EL05-17-000

  Subject: Estimation of damages accruing to Dynegy arising from a failure by the NYISO to accurately calculate locational installed capacity requirements in NYISO during the summer of 2002.

Constellation Energy Group

- FERC proceeding (*Maryland Public Utility Commission, et al., v. PJM Interconnection, LLC*, Docket No. EL08-67-000)

  Subject: "Just and reasonableness" of PJM's Reliability Pricing Mechanism.

Government of Belize, Public Utility Commission

- Proceeding before the Belize Public Utility Commission, *In the Matter of the Public Utilities Commission Initial Decision in the 2008 Annual Review Proceeding for Belize Electricity Limited*.

Subject: Arbitration and Independent Expert's report, in dispute between the Belize PUC and Belize Electricity Limited in an annual electric rate tariff review, as required under Belize law.

Federal Energy Regulatory Commission

- Technical hearings on wholesale electric capacity market design.

  Subject: Analysis of proposal to revise RTO capacity market design developed by the American Forest and Paper Association.

Dogwood Energy, LLC

- Proceeding before the Missouri Public Service Commission, *In the Matter of the Application of Aquila, Inc., d/b/a Aquila Networks - MPS and Aquila Case No. EO-2008-0046, Networks - L&P for Authority to Transfer Operational Control of Certain Transmission Assets to the Midwest Independent Transmission System Operator, Inc.*, Case No. EO-2008-0046.

  Subject: Cost-benefit analysis to determine whether Aquila should join either the Midwest Independent System Operator (MISO) or the Southwest Power Pool (SPP).

Independent Power Producers of New York

- FERC proceeding (*Re: New York Independent System Operator, Inc.*, Docket No. ER08-283-000)

  Subject: Revisions to the installed capacity (ICAP) market demand curves in the New York control area, which are designed to provide economic incentives for new generation development.

Empresa Eléctrica de Guatemala

- Rate proceeding before the Comisión Nacional de Energía Eléctrica

  Subject: Rate of return for an electric distribution company

Electric Power Supply Association

- FERC proceeding (*Re: Midwest Independent Transmission System Operator, Inc.*, Docket No. ER07-1182-000)

Subject: Critique of cost-benefit analysis by MISO Independent Market Monitor concluding that permanent establishment of Broad Constrained Area mitigation was appropriate.

Constellation Energy Commodities Group, LLC

- FERC proceeding regarding rate application for ancillary services by Ameren Energy (*Re: Ameren Energy Marketing Company and Ameren Energy, Inc*., Docket Nos. ER07-169-000 and ER07-170-000)
- Subject: Analysis and testimony on appropriate "opportunity cost" rates for ancillary services, including regulation service and spinning reserve service. Case settled prior to testimony being filed.

Suiza Dairy Corporation

- Rate proceeding before the Office of Milk Industry Regulatory Administration of Puerto Rico.
- Subject: Analysis and testimony on the appropriate rate of return for regulated milk processors in the Commonwealth of Puerto Rico.

DPL Inc.

- Proceeding before the Ohio Board of Tax Appeals (*DPL, Inc. and its subsidiaries v. William W. Wilkins, Tax Commissioner of Ohio*, Case No. 2004-A-1437)

  Subject: Economic impacts of generation investment and qualification of electric utility investments as "manufacturing" investments for purposes of state investment tax credits.

IGI Resources, LLC and BP Canada Energy Marketing Corp.

- FERC proceeding regarding the rate application by Gas Transmission Northwest Corporation (*Re: Gas Transmission Northwest*, Docket No. RP06-407-000)

  Subject: Natural gas supplies, economic lifetime, and depreciation rates.

Baltimore Gas and Electric Co.

- Maryland Public Service Commission (Case No. 9099)

Subject: Standard Offer Service pricing. Testimony focused on factors driving electric price increases since 1999, and estimates of rates under continued regulation

- Maryland Public Service Commission (Case No. 9073)

  Subject: Stranded costs of generation. Testimony focused on analysis of benefits of competitive wholesale power industry.

- Maryland Public Service Commission (Case No. 9063)

  Subject: Optimal structure of Maryland's electric industry. Testimony focused on the benefits of competitive wholesale electric markets. Presented independent estimates of benefits of restructuring since 1999.

Pemex-Gas y Petroquímica Básica

- Expert report in a rate proceeding. Presented analysis before the Comisión Reguladora de Energía on the appropriate rate of return for the natural gas pipeline industry.

BP Canada Marketing Corp.

- FERC proceeding regarding the rate application by Northern Border Pipeline Company (*Re: Northern Border Pipeline*, Docket No. RP06-072-000)

  Subject: Natural gas supplies, economic lifetime, and depreciation rates.

Transmission Agency of Northern California

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket No. ER09-1521-000)

  Subject: Analysis of appropriate return on equity, capital structure, and overall cost of capital. Case settled prior to filing expert testimony.

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket No. ER08-1318-000)

  Subject: Analysis of appropriate return on equity, capital structure, and overall cost of capital. Case settled prior to filing expert testimony.

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket No. ER07-1213-000)

Subject: Analysis of appropriate return on equity, capital structure, and overall cost of capital. Case settled prior to filing expert testimony.

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket No. ER06-1325-000)

  Subject: Analysis of appropriate return on equity, capital structure, and overall cost of capital. Case settled prior to filing expert testimony.

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket No. ER05-1284-000)

  Subject: Analysis of appropriate return on equity, capital structure, and overall cost of capital. Case settled prior to filing expert testimony.

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket Nos. ER03-409-000, ER03-666-000)

  Subject: Analysis and development of recommendation for the appropriate return on equity, capital structure, and overall cost of capital.

State of New Jersey Board of Public Utilities

- Merger application of Public Service Enterprise Group and Exelon Corporation (*I/M/O The Joint Petition Of Public Service Electric And Gas Company And Exelon Corporation For Approval Of A Change In Control Of Public Service Electric And Gas Company And Related Authorizations, BPU Docket No. EM05020106, OAL Docket No. PUC-1874-050*)

  Subject: Proposed merger between Exelon Corporation and PSEG Corporation. Testimony described the structure and results of a cost-benefit analysis to determine whether the proposed merger met the state's positive benefits test, and included analysis of market power, value of changes in nuclear plant operations, and merger synergies.

Sierra Pacific Power Corp.

- FERC proceeding regarding the rate application by Paiute Pipeline Company (*Re Paiute Pipeline Company* Docket No. RP05-163-000)

  Subject: Depreciation analysis, negative salvage, and natural gas supplies. Case settled prior to filing expert testimony.

Matanuska Electric

- Regulatory Commission of Alaska rate proceeding (*In the Matter of the Revision to Current Depreciation Rates Filed by Chugach Electric Association, Inc*., Docket No. U-04-102)

  Subject: Analysis of the reasonableness of Chugach electric's depreciation study.

Duke Energy North America, LLC

- FERC proceeding (*Re: Devon Power, LLC*, et al., Docket No. ER03-563-030)

  Subject: Appropriate market design for locational installed generating capacity in the New England market to ensure system reliability.

Keyspan-Ravenswood, LLC

- FERC proceeding, *KeySpan-Ravenswood, LLC v. New York Independent System Operator, Inc.*, Docket No. EL05-17-000

  Subject: Estimation of damages arising from a failure by the NYISO to accurately calculate locational installed capacity requirements in New York City during the summer of 2002.

Electric Power Supply Association

- FERC proceeding (*Re: PJM Interconnection, LLC*, Docket No. EL03-236-002)

  Subject: Analysis and critique of proposed pivotal supplier tests for market power in PJM identified load pockets.

Vermont Department of Public Service

- Vermont Public Service Board Rate Proceedings
  - Concurrent proceedings: *Re: Green Mountain Power Corp*., Dockets No. 7175 and 7176. Subject: Cost of capital and allowed return on equity under cost of service regulation, as well as under a proposed alternative regulation proposal.
  - *Re: Shoreham Telephone Company*, Docket No. 6914. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.
  - *Re: Vermont Electric Power Company*, Docket No. 6860. Subject: Development of a least-cost transmission system investment strategy to

analyze the prudence of a major high-voltage transmission system upgrade proposed by the Vermont Electric Power Company.

- *Re: Central Vermont Public Service Company*, Docket No. 6867. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.
- *Re: Green Mountain Power Corporation*, Docket No. 6866. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.

Pipeline shippers

- FERC proceeding regarding the rate application of Northern Natural Gas Company (*Re: Northern Natural Gas Company*, Docket No. RP03-398-000)

  Subject: Gas supply analysis to determine pipeline depreciation rates as part of an overall rate proceeding.

Arkansas Oklahoma Gas Corp.

- Oklahoma Corporation Commission rate proceeding (*Re: Arkansas Oklahoma Gas Corporation*, Docket No. 03-088)

  Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.
- Arkansas Public Service Commission rate proceedings
  - *In the Matter of the Application of Arkansas Oklahoma Gas Corporation for a General Change in Rates and Tariffs*, Docket No. 05-006-U. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.
  - *In the Matter of the Application of Arkansas Oklahoma Gas Corporation for a General Change in Rates and Tariffs*, Docket No. 02-24-U. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.

Entergy Nuclear Vermont Yankee, LLC

- Vermont Public Service Board proceeding (*Re: Petition of Entergy Nuclear Vermont Yankee for a Certificate of Public Good*, Docket No. 6812)

  Subject: Analysis of the economic benefits of nuclear plant generating capacity expansion as required for an application for a Certificate of Public Good.

Central Illinois Lighting Company

- Illinois Commerce Commission rate proceeding (*Re: Central Illinois Lighting Company*, Docket No. 02-0837)

  Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.

Citizens Utilities Corp.

- Vermont Public Service Board rate proceeding (*Tariff Filing of Citizens Communications Company requesting a rate increase in the amount of 40.02% to take effect December 15, 2001*, Docket No. 6596)

  Subject: Analysis of the prudence and economic used-and-usefulness of Citizens' long-term purchase of generation from Hydro Quebec, including the estimated environmental costs and benefits of the purchase.

Dynegy LNG Production, LP

- FERC proceeding (*Re: Dynegy LNG Production Terminal, LP*, Docket No. CP01-423-000). September 2001

  Subject: Analysis of market power impacts of proposed LNG facility development.

Missouri Gas Energy Corp.

- FERC rate proceeding (*Re: Kansas Pipeline Corporation*, Docket No. RP99-485-000)

  Subject: Gas supply analysis to determine pipeline depreciation rates as part of an overall rate proceeding.

Green Mountain Power Corp.

- Vermont Public Service Board rate proceedings
  - *In the Matter of Green Mountain Power Corporation requesting a 12.93% Rate Increase to take effect January 22, 1999*, Docket No. 6107. Subject: Analysis of the appropriate discount rate, treatment of environmental costs, and the treatment of risk and uncertainty as part of a major power-purchase agreement with Hydro-Quebec.
  - *Investigation into the Department of Public Service's Proposed Energy Efficiency Utility*, Docket No. 5980. Subject: Analysis of distributed utility planning methodologies and environmental costs.

- *Tariff Filing of Green Mountain Power Corporation requesting a 16.7% Rate Increase to take effect 7/31/97*, Docket No. 5983. Subject: Analysis of distributed utility planning methodologies and avoided electricity costs.
- *Tariff Filing of Green Mountain Power Corporation requesting a 16.7% Rate Increase to take effect 7/31/97*, Docket No. 5983. Subject: Valuation of a long-term power purchase contract with Hydro-Quebec in the context of a determination of prudence and economic used-and-usefulness.

United Illuminating Company

- Connecticut Dept. of Public Utility Control proceeding (*Application of the United Illuminating Company for Recovery of Stranded Costs*, Docket No. 99-03-04)

  Subject: Development and application of dynamic programming models to estimate nuclear plant stranded costs.

COMMERCIAL LITIGATION EXPERIENCE

- *Idaho Power Co. v. Glenns Ferry Cogeneration Partners, L.P.*, U.S. District Court, District of Idaho, Case No. 1:11-cv-00565-CWD. Expert report on damages associated with breach of power sales contract.

- *Vacqueria Tres Monjitas and Suiza Dairy, Inc. v. Jose O. Laboy, in his Official capacity, as the Secretary of the Department of Agriculture for the Commonwealth of Puerto Rico, and Juan R. Pedro-Gordian, in his official capacity, as Administrator of the Office of the Milk Industry Regulatory Administration for the Commonwealth of Puerto Rico.* U.S. District Court, District of Puerto Rico, Civil Case No. 04-1840. Determined the appropriate "country risk" premium for the fresh milk dairy industry in the Commonwealth of Puerto Rico.

- *Lorali, Ltd., et al. v. Sempra Energy Solutions, LLC, et al*. Damages associated with abrogation of retail electric supply contracts.

- *IMO Industries v. Transamerica.* Estimated the appropriate discount rate to use for estimating damages over time associated with a failure of the insurance companies to reimburse asbestos-related damage claims and the resulting losses to the firm's value.

- *John C. Lincoln Hospital v. Maricopa County.* Performed statistical analysis to determine the value of a class of unpaid hospital insurance claims.

- *Catamount/Brownell, LLC. v. Randy Rowland.* Prepared an expert report on the damages associated with breach of commercial lease.

- *Lyubner v. Sizzling Platters, Inc.*. Performed an econometric analysis of damage claims based on sales impacts associated with advertising.

- *Pietro v. Pietro*. Estimated pension benefits arising from a divorce case.

- *Nat'l. Association of Electric Manufacturers v. Sorrell.* U.S. District Court for the District of Vermont. Expert report and testimony on the costs of labeling fluorescent lamps and the impacts of labeling laws on the demand for electricity.

ARBITRATION CASES

***TransCanada Hydro Northeast, Inc. v. Town of Littleton, New Hampshire*, (CPR File No. G-09-24).**

Subject: dispute regarding valuation for property tax purposes of a hydroelectric facility located on the Connecticut River.

Served as neutral on a three-person arbitration panel.

***Belize Electricity Limited v. Belize Public Utilities Commission* (Claim No. 512 of 2008)**.

Subject: Proceeding before the Supreme Court of Belize alleging that the Final Decision by the Belize Public Utilities Commission setting electric rates and tariffs for the 2008-2009 period were unreasonable and non-compensatory.

Prepared independent report on behalf of the Belize Supreme Court for arbitration of the dispute.

SELECTED BUSINESS CONSULTING EXPERIENCE

- For the COMPETE coalition, prepared a report on the economic impacts of state subsidized electric generating plants.
- For a confidential client, provided analysis on rate of return and capital structure, as well as key business and financial risks, for renegotiation of a long-term power-purchase agreement.
- For the Manhattan Institute, prepared a comprehensive report on the economic impacts of shutdown of the Indian Point Nuclear Facility.

- For Energy Choice Now, prepared a report on the economic benefits of retail electric competition in Michigan.
- For the COMPETE Coalition, prepared a report on how electric competition creates economic growth.
- For an industry group, developed econometric models of the impacts of shale gas production on U.S. natural gas and electric prices.
- For an environmental advocacy group, critically evaluated the financial implications of operating restrictions for an off-shore wind generating facility stemming from requirements under the U.S. Endangered Species Act.
- For a major investor-owned utility in the US, prepared a new system of short-term peak and energy forecasting models.
- For a major wholesale electric generation company, prepared comprehensive economic impact studies for use in FERC hydroelectric relicensing proceedings.
- For a major investor-owned utility in the Southwest US, prepared a detailed econometric model and wrote a comprehensive report on residential price elasticity that was required by regulators.
- For a major investor-owned utility in the Southwest US, developed a methodology to value nuclear plant leases that incorporated future uncertainty regarding greenhouse gas regulations.
- Faculty member, PURC/World Bank International Training Program on Utility Regulation and Strategy, University of Florida, Public Utility Research Center, Gainesville, FL, 2008 – 2009. Courses taught:
    - Sector Issues: Basic Techniques–Energy
    - Sector Issues in Rate Design: Energy
    - Sector Issues in Rate Design: Energy–Case Studies
    - Transmission Pricing Issues
- For a major solar energy firm, evaluated costs and benefits of alternative solar technologies; assisted with siting and transmission access issues.
- For the South African Department of Minerals and Energy, recommended pricing methods and regulatory accounts to ensure that petroleum product prices appropriately reflected costs and to enhance the incentives for industry investment "Final Report for Task 141. "
- For industrial customers in the State of Vermont, prepared a position paper on the impacts of demand side management funding on electric rates and competitiveness.

- For a major New York brokerage firm, performed a fairness opinion valuation of a gas-fired electric generating facility.
- For electric utilities undergoing restructuring, developed comprehensive economic models to value buyer offers associated with nuclear power plant divestitures.
- For a large municipal electric utility in Florida, analyzed real option values of alternative proposed purchased generation contracts whose strike prices were tied to future natural gas and oil prices, and developed contract recommendations.
- For a municipal electric utility in Florida, developed an analytical model to determine risk-return tradeoffs of alternative generation portfolios, identify an efficient frontier of generation asset portfolios, and recommended asset purchase and sale strategies.
- For Central Vermont Public Service Corp. and Green Mountain Power Corp., developed analyses of distribution capacity investments accounting for uncertainty over future peak load growth.
- For a major electric utility in Latin America, developed risk management strategies for hedging natural gas supplies with minimal up-front investment; prepared training materials for utility staff; and wrote the utility's risk management Policies and Procedures Manual.
- For a major nuclear plant owner and operator in the U.S., prepared reports of the economic benefits of nuclear plant operation and development.
- For the Electric Power Supply Association, prepared numerous policy papers addressing wholesale electric market design and competition.
- For the California Energy Commission, developed a new policy approach to renewables feed-in tariffs and developed portfolio analysis models to develop an "efficient frontier" of generation portfolios for the state.
- For a major nuclear plant owner and operator, assessed the likelihood of relicensing a specific nuclear plant in New England, given state regulatory concerns over on-site spent fuel storage.
- For a large investor-owned utility in the Southeast, analyzed alternative environmental compliance strategies that directly incorporated uncertainty over future emissions costs, environmental regulations, and alternative pollution control technology effectiveness.
- For a Special Legislative Committee of the Province of New Brunswick, served as an expert advisor on the development of a deregulated electric power market.

- For the Bonneville Power Administration, developed models to assess the economic impacts of local generation resource development in Washington State and Oregon.
- For an electric utility in the Pacific Northwest, assisted in negotiations surrounding relicensing of a large hydroelectric generating facility.
- Served as an expert advisor for the Northwest Power Planning Council regarding future power supplies, load growth, and economic growth.

EDUCATION

- PhD, Economics, University of Washington
- MA, Economics, University of Washington
- BSc, Mathematics and Economics (with honors), University of New Mexico

EMPLOYMENT HISTORY

- 2009–Present: Continental Economics, Inc., President.
- 2004–2009: Bates White, LLC, Partner, Energy Practice.
- 2003–2004: Vermont Dept. of Public Service, Director of Planning.
- 1998–2003: Navigant Consulting, Senior Managing Economist.
- 1996–1998: Adjunct Lecturer, School of Business, University of Vermont.
- 1993–1998: Green Mountain Power Corporation, Manager, Economic Analysis.
- 1990–1993: Adjunct Lecturer, Dept. of Business and Economics, Saint Martin's College.
- 1986–1993: Washington State Energy Office, Energy Policy Specialist.
- 1984–1986: Pacific Northwest Utilities Conference Committee, Energy Economist.
- 1983–1984: Idaho Power Corporation, Load Forecasting Analyst.

PROFESSIONAL ACTIVITIES

- Reviewer, *Energy*
- Reviewer, *The Energy Journal*
- Reviewer, *Energy Policy*

- Reviewer, *Journal of Regulatory Economics*

PROFESSIONAL ASSOCIATIONS

- Energy Bar Association
- International Association for Energy Economics
- Society for Benefit-Cost Analysis

PUBLICATIONS

Peer-reviewed journal articles

- Lesser, J, "The High Cost of Low-Value Wind Power," *Regulation*, Spring 2013, forthcoming.
- Lesser, J., "Wind Generation Patterns and the Economics of Wind Subsidies," *The Electricity Journal* 26, Jan/Feb. 2013, pp. 8-16.
- Lesser, J., "Gresham's Law of Green Energy," *Regulation*, Winter 2010-2011, pp. 12-18.
- Lesser, J., and E. Nicholson, "Abandon all Hope? FERC's Evolving Standards for Identifying Comparable Firms and Estimating the Rate of Return," *Energy Law Journal* 30 (April 2009): 105-132.
- Lesser, J. and X. Su. "Design of an Economically Efficient Feed-in Tariff Structure for Renewable Energy Development." *Energy Policy* 36 (March 2008) 981–990.
- Lesser, J. "The Economic Used-and-Useful Test: Its Origins and Implications for a Restructured Electric Industry." *Energy Law Journal* 23 (November 2002): 349–82.
- Lesser, J., and C. Feinstein. "Electric Utility Restructuring, Regulation of Distribution Utilities, and the Fallacy of 'Avoided Cost' Rules." *Journal of Regulatory Economics* 15 (January 1999): 93–110.
- Lesser, J., and C. Feinstein. "Defining Distributed Utility Planning." *The Energy Journal*, Special Issue, Distributed Resources: Toward a New Paradigm (1998): 41–62.
- Lesser, J., and R. Zerbe. "What Can Economic Analysis Contribute to the Sustainability Debate?" *Contemporary Policy Issues* 13 (July 1995): 88–100.

- Lesser, J., and R. Zerbe. "The Discount Rate for Environmental Projects." *Journal of Policy Analysis and Management* 13 (Winter 1994): 140–56.
- Lesser, J., and D. Dodds. "Can Utility Commissions Improve on Environmental Regulations?" *Land Economics* 70 (February 1994): 63–76.
- Lesser, J. "Estimating the Economic Impacts of Geothermal Resource Development." *Geothermics* 24 (Winter 1994): 52–69.
- Lesser, J. "Application of Stochastic Dominance Tests to Utility Resource Planning Under Uncertainty." *Energy* 15 (December 1990): 949–61.
- Lesser, J. "Resale of the Columbia River Treaty Downstream Power Benefits: One Road From Here to There." *Natural Resources Journal* 30 (July 1990): 609–28.
- Lesser, J., and J. Weber. "The 65 M.P.H. Speed Limit and the Demand for Gasoline: A Case Study for the State of Washington." *Energy Systems and Policy* 13 (July 1989): 191–203.
- Lesser, J. "The Economics of Preference Power." *Research in Law and Economics* 12 (1989): 131–51.

Books and contributed chapters

- Lesser, J., and L.R. Giacchino, *Principles of Utility Corporate Finance*, Vienna, VA: Public Utilities Reports, 2011.
- Lesser, J., and L.R. Giacchino. *Fundamentals of Energy Regulation*, Vienna, VA: Public Utilities Reports, 2007.
- Lesser, J., and R. Zerbe. "A Practitioner's Guide to Benefit-Cost Analysis." In *Handbook of Public Finance*, edited by F. Thompson, 221–68. New York: Rowan and Allenheld, 1998.
- Lesser, J., D. Dodds, and R. Zerbe. *Environmental Economics and Policy*, Reading: MA: Addison Wesley Longman, 1997.

Trade press publications

- Lesser, J., "Talk Is Cheap: The UN's Doha Conference Strikes Out . . . Again," Natural Gas and Electricity (February 2013): 27-29.
- Lesser, J. "Frack Attack: Environmentalists and Hollywood Renew Attacks on Hydraulic Fracturing," *Natural Gas and Electricity* (December 2012): 30-32.

- Lesser, J., "Courts Shut Down Nuclear Licensing, Not Wasting a Waste Crisis," *Natural Gas and Electricity* (October 2012): 27-29.
- Lesser, J., "Wind Power in the Windy City, Not There When Needed," *Energy Tribune*, July 25, 2012.
- Lesser, J. "How Will EPA's Newest Regulations Affect Electric Markets?" *Natural Gas and Electricity* (June 2012): 30-32.
- Lesser, J. "Pipeline Petulance," *Natural Gas and Electricity* (March 2012): 27-29.
- Lesser, J. "Global Warming, Climate Change, er Climate Volatility: 2012 and Beyond," *Natural Gas and Electricity* (January 2012): 22-24.
- Lesser, J., "Sunburnt: Solyndra, Subsidies, and the Green Jobs Debacle," *Natural Gas & Electricity* (November 2011):30-32..
- Lesser, J., "Illinois an Example of when the Wind Doesn't Blow," *Natural Gas & Electricity* (September 2011):27-29.
- Lesser, J., "Salmon and Wind Dueling for Subsidies in the Pacific Northwest," *Natural Gas & Electricity* (July 2011):18-20.
- Lesser, J., "Nuclear Fallout," *Natural Gas & Electricity* (May 2011):31-33.
- Lesser, J., "Texas Two-Step: EPA's Greenhouse Gas Permitting Takeover," *Natural Gas & Electricity* (March 2011):21-23.
- Lesser, J., "Looking Forward: Energy and the Environment through 2012," *Natural Gas & Electricity* (January 2011):30-32.
- Lesser, J., "First-Mover Disadvantage: Offshore Wind's False Economic Promises," *Natural Gas & Electricity* (November 2010): 26-28.
- Lesser, J., "Will the BP Disaster Affect Natural Gas and Electricity Markets?," *Natural Gas & Electricity* (August 2010): 23-24.
- Lesser, J., "Renewable Energy and the Fallacy of 'Green' Jobs," *The Electricity Journal* (August 2010):45-53.
- Lesser, J., "Let the Tough Choices Begin: Affordable or Green?," *Natural Gas & Electricity* (June 2010): 27-29.

- Lesser, J., "Will Shale Gas Production be Damaged by Too Many Fraccing Complaints?," *Natural Gas & Electricity* (April 2010): 31-32.
- Lesser, J., "As the Climate Turns: The Saga Continues," *Natural Gas & Electricity* (February 2010): 29-32.
- Lesser, J. and N. Puga, "Public Policy and Private Interests: Why Transmission Planning and Cost-Allocation Methods Continue to Stifle Renewable Energy Policy Goals," *The Electricity Journal* (December 2009): 7-19.
- Lesser, J, "Short Circuit: Will Electric Cars Provide Energy and Environmental Salvation?" *Natural Gas & Electricity* (November 2009): 27-28.
- Lesser, J., "Green is the New Red: The High Cost of Green Jobs," *Natural Gas & Electricity* (August 2009): 31-32.
- Lesser, J., "Regulating Greenhouse Gas Emissions: EPA Gets Down," *Natural Gas & Electricity* (June 2009): 31-32.
- Lesser, J., "Being Reasonable While Regulating Greenhouse Gas Emissions under the Clean Air Act," *Natural Gas & Electricity* (April 2009): 30-32.
- Lesser, J., "Renewables, Becoming Cheaper, Are Suddenly Passé," *Natural Gas & Electricity* (February 2009): 30-32.
- Lesser, J., "Measuring the Costs and the Benefits of Energy Development," *Natural Gas & Electricity* (December 2008): 30-32.
- Lesser, J., "Comparing the Benefits and the Costs of Energy Development," *Natural Gas & Electricity* (October 2008): 31-32.
- Lesser, J., "New Source Review Is Still Anything but Routine," *Natural Gas & Electricity* (August 2008): 31-32.
- Lesser, J., and N. Puga, "PV versus Solar Thermal," *Public Utilities Fortnightly* 146 (July 2008), pp. 16-20, 27.
- Lesser, J., "Kansas Secretary Unilaterally Bans Coal Plants," *Natural Gas & Electricity* (June 2008): 30-32.
- Lesser, J., "Seeing Through a Glass, Darkly, Banks Approach Coal-Fired Power Financing," *Natural Gas & Electricity* (April 2008): 29-31.

- Lesser, J., "The Energy Independence and Security Act of 2007: No Subsidy Left Behind," *Natural Gas & Electricity* (February 2008): 29-31.

- Lesser, J., "Control of Greenhouse Gases: Difficult with Either Cap-and-Trade or Tax-and-Spend." *Natural Gas & Electricity* (December 2007): 28-31.

- Lesser, J., "Déjà vu All Over Again: The Grass was not Greener Under Utility Regulation." *The Electricity Journal* 20 (December 2007): 35–39.

- Lesser, J., "Blowin' in the Wind: Renewable Energy Mandates, Electric Rates, and Environmental Quality." *Natural Gas & Electricity* (October 2007): 26-28.

- Lesser, J., "No Leg to Stand On." *Natural Gas & Electricity* (August 2007): 28–31.

- Lesser, J., "Goldilocks Chills Out." *Natural Gas & Electricity* (July 2007): 26–28.

- Lesser, J., "Goldilocks and the Three Climates." *Natural Gas & Electricity* (April 2007): 22–24.

- Lesser, J., "Command-and-Control Still Lurks in Every Legislature." *Natural Gas & Electricity* (February 2007): 8–12.

- Lesser, J., and G. Israilevich, "The Capacity Market Enigma." *Public Utilities Fortnightly* 143 (December 2005): 38-42.

- Lesser, J., "Regulation by Litigation." *Public Utilities Fortnightly* 142 (October 2004): 24–29.

- Lesser, J., "ROE: The Gorilla is Still at the Door." *Public Utilities Fortnightly* 144 (July 2004): 19–23.

- Lesser, J., and S. Chapel, "Keys to Transmission and Distribution Reliability." *Public Utilities Fortnightly* 142 (April 2004): 58–62.

- Lesser, J., "DCF Utility Valuation: Still the Gold Standard?" *Public Utilities Fortnightly* 141 (February 15, 2003): 14–21.

- Lesser, J., "Welcome to the New Era of Resource Planning: Why Restructuring May Lead to More Complex Regulation, Not Less." *The Electricity Journal* 15 (July 2002): 20–28.

- Lesser, J., and C. Feinstein, "Identifying Applications for Distributed Generation: Hype vs. Hope." *Public Utilities Fortnightly* 140 (June 1, 2002): 20–28.

- Lesser, J., et al., “Utility Resource Planning: The Need for a New Approach.” *Public Utilities Fortnightly* 140 (January 15, 2002): 24–27.
- Lesser, J., “Distribution Utilities: Forgotten Orphans of Electric Restructuring?” *Public Utilities Fortnightly* 137 (March 1, 1999): 50–55.
- Lesser, J., “Regulating Distribution Utilities in a Restructured World.” *The Electricity Journal* 12 (January/February 1999): 40–48.
- Lesser, J., “Is it How Much or Who Pays? A Response to Rothkopf.” *The Electricity Journal* 10 (December 1997): 17–22.
- Lesser, J., and M. Ainspan, “Using Markets to Value Stranded Costs.” *The Electricity Journal* (October 1996): 66–74.
- Lesser, J., “Economic Analysis of Distributed Resources: An Introduction.” *Proceedings*, First Annual Conference on Distributed Resources, Electric Power Research Institute, Kansas City, MO, July 1995.
- Lesser, J., “Distributed Resources as a Competitive Opportunity: The Small Utility Perspective.” *Proceedings*, First Annual Conference on Distributed Resources, Electric Power Research Institute, Kansas City, MO, July 1995.
- Lesser, J., and M. Ainspan, “Retail Wheeling: Deja vu All Over Again?” *The Electricity Journal* 7 (April 1994): 33–49.
- Lesser, J., “An Economically Rational Approach to Least-Cost Planning: Comment.” *The Electricity Journal* 4 (October 1991).
- Lesser, J., “Long-Term Utility Planning Under Uncertainty: A New Approach.” Paper presented for the Electric Power Research Institute: *Innovations in Pricing and Planning*, May 1990.
- Lesser, J., “Centralized vs. Decentralized Resource Acquisition: Implications for Bidding Strategies.” *Public Utilities Fortnightly* (June 1990).
- Lesser, J., “Most Value—The Right Measure for the Wrong Market?” *The Electricity Journal* 2 (December 1989): 47–51.

Other Publications

- Lesser, J., “Wind power creates market havoc, is unreliable and costly,” *Columbus* (Ohio) *Dispatch*, November 22, 2012.

- Lesser, J., and R. Bryce, "The High Cost of Closing Indian Point," *New York Post*, August 8, 2012.
- Lesser, J., "Cap-and-Trade for Gasoline?" *Wall Street Journal*, June 14, 2008, A14.
- Lesser, J., "Overblown Promises: The Hidden Costs of Symbolic Environmentalism." *Livin' Vermont* (January/February 2005): 7, 27.

Selected speaking engagements

- "The Economic Benefits of Electric Competition," Key Note Address, 17th Ohio Industrial Energy Users Conference, February 20, 2013.
- "Public Policy and Energy Markets: Good Intentions" Gone Astray," presentation to the Independent Power Producers of New York, Fall Conference, September 13, 2012.
- "EPA Regulation of Generator Emissions – Key Market Issues," Energy Bar Association, Annual Meeting, April 28, 2012.
- "Competitive Energy Markets: How are they Working?" Constellation Executive Energy Forum, November 2, 2011.
- "The Failures of Transmission Planning and Policy," Harvard Electric Policy Group, February 25, 2010.
- "Financing the Smart Grid," Energy Bar Association Seminar, Washington, DC, December 4, 2009.
- "Renewable Power: At the Crossroads of Economics and Policy," Presentation to the Utilities State Government Organization, Newport, Rhode Island, July 13, 2009.
- "The Stimulus Act and Laws they Didn't Teach You in Law School," presentation to the 27th National Regulatory Conference, Williamsburg, VA, May 19, 2009.
- "Rate Recovery for Capital Intensive Generation: Rate Base and Construction Work in Progress," Law Seminars International, Las Vegas, NV, February 5, 2009.
- "Financial Risks Faced by Regulated Utilities: Implications for the Cost of Capital and Ratemaking Policies," Law Seminars International, Las Vegas, NV, February 7, 2008.
- "Alternative Regulatory Structures and Tariff Mechanisms: Practical approaches to providing low-cost, environmentally responsible energy and how to avoid some dangerous pitfalls." Western Energy Institute, October 1, 2007.

- "Economics and Energy Regulation." Law Seminars International, Washington, DC, March 15-16, 2007.
- "Energy in the Northeast: Resource Adequacy & Reliability." Law Seminars International, Boston, MA, October 16–17, 2006.
- "Energy in the Southwest: New Directions in Energy Markets and Regulations." Law Seminars International, Santa Fe, NM, July 14, 2006.
- "Electricity and Natural Gas Regulation: An Introduction." Law Seminars International, Washington, DC, March 17–18, 2005.

FES-INT-03-005

REQUEST:

To which segment of DEO's business are ESSC revenues allocated (distribution, transmission, generation, etc.)? If multiple segments, please provide rationale for the allocation.

RESPONSE:

Objection. This Interrogatory is overly broad and unduly burdensome and further seeks to elicit information that is irrelevant or not reasonably calculated to lead to the discovery o of admissible evidence. Without waiving said objection, to the extent discoverable, and in the spirit of discovery, ESSC revenue is recorded on the books of company business unit 75030, or Commercial Power.

PERSON RESPONSIBLE: William Don Wathen Jr.

REDACTED

DUKE ENERGY OHIO, INC.
CASE NO. 12-1682-EL-AIR
PLANT IN SERVICE BY ACCOUNTS AND SUBACCOUNTS
AS OF MARCH 31, 2012

NON-JURISDICTIONAL ELECTRIC PLANT

DATA: "X" ACTUAL ESTIMATED
TYPE OF FILING: "X" ORIGINAL UPDATED REVISED
WORK PAPER REFERENCE NO(S).:

SCHEDULE B-2.1
PAGE 1 OF 5
WITNESS RESPONSIBLE:
C. J. COUNCIL

LINE NO.	F.E.R.C. ACCT. NO.	COMPANY ACCT. NO.	ACCOUNT TITLE	TOTAL COMPANY	ADJUSTMENTS	ADJUSTED TOTAL COMPANY	ALLOCATION %	ALLOCATED JURISDICTION
				$				$
1	Various	Various	Electric Production - Steam	3,405,817,368		3,405,817,368	0.000%	0
2	Various	Various	Electric Production - Other	23,646,273		23,646,273	0.000%	0
3	Various	Various	Electric Transmission Plant	616,403,010		616,403,010	0.000%	0
4	Various	Various	Electric Production/Transmission Plant - DENA Plants	234,211		234,211	0.000%	0
5			Total Non-Jurisdictional Electric Plant	4,046,100,862		4,046,100,862		0

Exhibit JAL-4

Exhibit JAL-4

DUKE ENERGY OHIO, INC.
CASE NO. 12-1682-EL-AIR
PLANT IN SERVICE BY ACCOUNTS AND SUBACCOUNTS
AS OF MARCH 31, 2012

DISTRIBUTION PLANT

DATA: "X" ACTUAL ESTIMATED
TYPE OF FILING: "X" ORIGINAL UPDATED REVISED
WORK PAPER REFERENCE NO(S).:

SCHEDULE B-2.1

WITNESS RESPONSIBLE:
C. J. COUNCIL

LINE NO.	F.E.R.C. ACCT. NO.	COMPANY ACCT. NO.	ACCOUNT TITLE	TOTAL COMPANY	ADJUSTMENTS	ADJUSTED TOTAL COMPANY	ALLOCATION %	ALLOCATED JURISDICTION
				$				$
1	360	3600	Land and Land Rights	13,109,977		13,109,977	100.000%	13,109,977
2	360	3601	Rights of Way	26,110,943		26,110,943	100.000%	26,110,943
3	361	3610	Structures and Improvements	8,317,815		8,317,815	100.000%	8,317,815
4	362	3620	Station Equipment	182,040,569	(17,100,300)	164,940,269	100.000%	164,940,269
5	362	3622	Major Equipment	103,229,213	(2,103,326)	101,125,887	100.000%	101,125,887
6	362	3635	Station Equipment Electronic	2,620,440	(2,719,820)	(99,380)	100.000%	(99,380)
7	364	3640	Poles, Towers & Fixtures	243,486,355	(1,162,056)	242,324,299	100.000%	242,324,299
8	365	3650, 3651	Overhead Conductors and Devices	396,969,778	(12,365,335)	384,604,443	100.000%	384,604,443
9	366	3660	Underground Conduit	88,227,723		88,227,723	100.000%	88,227,723
10	367	3670	Underground Conductors and Devices	282,336,871		282,336,871	100.000%	282,336,871
11	368	3680, 3681	Line Transformers	367,228,972		367,228,972	100.000%	367,228,972
12	368	3682	Customer Transformer Installations	5,272,832		5,272,832	100.000%	5,272,832
13	369	3691	Services - Underground	3,391,901		3,391,901	100.000%	3,391,901
14	369	3692	Services - Overhead	64,385,178		64,385,178	100.000%	64,385,178
15	370	3700	Meters	41,968,249		41,968,249	100.000%	41,968,249
16	370	3701	Leased Meters	17,699,187		17,699,187	100.000%	17,699,187
17	370	3702	Utility of the Future Meters	40,433,742	(40,433,742)	0	100.000%	0
18	371	3710	Installations on Customers' Premises	241,509		241,509	100.000%	241,509
19	371	3712	Company Owned Outdoor Light	714,040		714,040	100.000%	714,040
20	372	3720	Leased Property on Customers' Premises	102,503		102,503	100.000%	102,503
21	373	3730, 3731	Street Lighting	21,127,345		21,127,345	100.000%	21,127,345
22	373	3732	Street Lighting - Boulevard	28,103,634		28,103,634	100.000%	28,103,634
23	373	3733	Light Security OL POL Flood	17,694,862		17,694,862	100.000%	17,694,862
24	373	3734	Light Choice OLE - Public	1,364,763		1,364,763	100.000%	1,364,763
25			Total Electric Distribution Plant	1,956,178,401	(75,884,579)	1,880,293,822		1,880,293,822

Exhibit JAL-4

DUKE ENERGY OHIO, INC.
CASE NO. 12-1682-EL-AIR
PLANT IN SERVICE BY ACCOUNTS AND SUBACCOUNTS
AS OF MARCH 31, 2012

GENERAL PLANT

DATA: "X" ACTUAL ESTIMATED
TYPE OF FILING: "X" ORIGINAL UPDATED REVISED
WORK PAPER REFERENCE NO(S).: WPB-7a

SCHEDULE B-2.1

WITNESS RESPONSIBLE:
C. J. COUNCIL

LINE NO.	F.E.R.C. ACCT. NO.	COMPANY ACCT. NO.	ACCOUNT TITLE	TOTAL COMPANY	ADJUSTMENTS	ADJUSTED TOTAL COMPANY	ALLOCATION %	ALLOCATED JURISDICTION
				$				$
1	303	3030	Miscellaneous Intangible Plant	34,776,041	(5,191,891)	29,584,150	92.257%	27,293,450
2	389	3890	Land and Land Rights	949,213		949,213	92.257%	875,715
3	390	3900	Structures and Improvements	25,029,892	(46,746)	24,983,146	92.257%	23,048,701
4	391	3910	Office Furniture and Equipment	502,944		502,944	92.257%	464,001
5	391	3911	Electronic Data Processing Equipment	2,403,741	(1,069,127)	1,334,614	92.257%	1,231,275
6	391	3920	Transportation Equipment	1,302,268		1,302,268	92.257%	1,201,433
7	391	3921	Trailers	2,940,408		2,940,408	92.257%	2,712,732
8	393	3930	Stores Equipment	1,090,920		1,090,920	92.257%	1,006,450
9	392	3940	Tools, Shop & Garage Equipment	14,796,560		14,796,560	92.257%	13,650,862
10	392	3950	Laboratory Equipment	125,110		125,110	92.257%	115,423
11	393	3960	Power Operated Equipment	1,555,719		1,555,719	92.257%	1,435,260
12	393	3970	Communication Equipment	53,946,585	(40,153,265)	13,793,320	92.257%	12,725,303
13	394	3980	Miscellaneous Equipment	83,798		83,798	92.257%	77,310
14			Total Electric General Plant	139,503,199	(46,461,029)	93,042,170		85,837,915
15			Total Electric Plant	6,141,782,462	(122,345,608)	6,019,436,854		1,966,131,737

Exhibit JAL-4

DUKE ENERGY OHIO, INC.
CASE NO. 12-1682-EL-AIR
PLANT IN SERVICE BY ACCOUNTS AND SUBACCOUNTS
AS OF MARCH 31, 2012

COMMON PLANT - EXCLUDING SMARTGRID

DATA: "X" ACTUAL ESTIMATED
TYPE OF FILING: "X" ORIGINAL UPDATED REVISED
WORK PAPER REFERENCE NO(S).: WPB-7a

SCHEDULE B-2.1
PAGE 4 OF 5
WITNESS RESPONSIBLE:
C. J. COUNCIL

LINE NO.	F.E.R.C. ACCT. NO.	COMPANY ACCT. NO.	ACCOUNT TITLE	TOTAL COMPANY	ADJUSTMENTS	ADJUSTED TOTAL COMPANY	ALLOCATION %	ALLOCATED JURISDICTION
				$				$
1		1030	Miscellaneous Intangible Plant	121,520,890		121,520,890	44.821%	54,466,878
2		1890	Land and Land Rights	2,121,647		2,121,647	44.821%	950,943
3		1891	Rights of Way	37,969		37,969	44.821%	17,018
4		1900	Structures & Improvements	129,745,709	(1,968,452)	127,777,257	44.821%	57,271,044
5		1910	Office Furniture & Equipment	4,220,950	(6,594)	4,214,356	44.821%	1,888,917
6		1911	Electronic Data Processing - Non SmartGrid	693,843		693,843	44.821%	310,987
7		1920	Transportation Equipment	85,311		85,311	44.821%	38,237
8		1921	Trailers	474,273		474,273	44.821%	212,574
9		1930	Stores Equipment	189,750		189,750	44.821%	85,048
10		1940	Tools, Shop & Garage Equipment	1,829,999	(52,910)	1,777,089	44.821%	796,509
11		1950	Laboratory Equipment	23,250		23,250	44.821%	10,421
12		1960	Power Operated Equipment	153,899		153,899	44.821%	68,979
13		1970	Communication Equipment - Non SmartGrid	27,931,369	(8,238)	27,923,131	44.821%	12,515,427
14		1980	Miscellaneous Equipment	429,603	(8,081)	421,522	44.821%	188,930
15		1990, 1991	Retirement Work in Process - ARO	99,735		99,735	44.821%	44,702
15			Total Common Plant - Excluding SmartGrid	289,558,197	(2,044,275)	287,513,922		128,866,614
16		83.50%	Common Plant Allocated to Electric (excluding SmartGrid)	241,781,095	(1,706,970)	240,074,125		107,603,623

Exhibit JAL-4

DUKE ENERGY OHIO, INC.
CASE NO. 12-1682-EL-AIR
PLANT IN SERVICE BY ACCOUNTS AND SUBACCOUNTS
AS OF MARCH 31, 2012

COMMON PLANT - SMARTGRID

DATA: "X" ACTUAL ESTIMATED
TYPE OF FILING: "X" ORIGINAL UPDATED REVISED
WORK PAPER REFERENCE NO(S).:

SCHEDULE B-2.1

WITNESS RESPONSIBLE:
C. J. COUNCIL

LINE NO.	F.E.R.C. ACCT. NO.	COMPANY ACCT. NO.	ACCOUNT TITLE	TOTAL COMPANY	ADJUSTMENTS	ADJUSTED TOTAL COMPANY	ALLOCATION %	ALLOCATED JURISDICTION
				$				$
1		1911	Electronic Data Processing - SmartGrid	113,194	(113,194)	(0)	100.000%	0
2		1970	Communication Equipment - SmartGrid	27,261,331	(27,261,331)	0	100.000%	0
3			Total Common Plant - SmartGrid	27,374,525	(27,374,525)	(0)	100.000%	0
4		(1)	Common Plant Allocated to Electric - SmartGrid	13,991,120	(13,991,120)	0	100.000%	0
5			Total Common Plant	316,932,722	(29,418,800)	287,513,922		128,866,614
6			Total Common plant allocated to Electric	255,772,215	(15,698,090)	240,074,125		107,603,623
7			Total Electric Plant Including Allocated Common	6,397,554,677	(138,043,698)	6,259,510,979		2,073,735,360

(1) Allocation of Common Plant / SmartGrid to electric determined by SmartGrid filings

Duke Energy Ohio
Present Value Benefit of ESP Compared to MRO [a]

Line		Jan '12-Dec '12	Jan '13-Dec '13	Jan '14-Dec '14	Jan '15-May '15
	Price Forecasts				
1	Projected Legacy ESP Price [b]	$79.19	$74.45	$76.22	$75.44
2	*Projected Retail Market Price* [c]	$61.38	$66.31	$78.65	$89.00
3	MRO Blend % (of Market Price)	10%	20%	30%	40%
4	MRO Price Blended Rate ($/MWh)	**$77.41**	**$72.82**	**$76.95**	**$80.86**
5	Projected Retail Market Price (Line 2)	$61.38	$66.31	$78.65	$89.00
6	Electric Security Stabilitizatio Charge [d]	5.37	5.29	5.19	-
7	Proposed SSO Price in ESP	**$66.75**	**$71.60**	**$83.85**	**$89.00**
	Revenue Comparison (MRO v. ESP)				
8	Total Revenue at MRO Rate	$1,584,804,517	$1,515,400,007	$1,629,570,849	$700,610,416
9	Total Revenue at ESP Rates				
10	All kWh at Average ESP Rate	$1,366,630,966	$1,489,967,594	$1,775,667,622	$771,119,852
11	Less: Discount for PIPP Load *(see workpaper)* [e]	(1,034,686)	(1,175,033)	(1,458,150)	(556,176)
12	Total Revenue at ESP Rates	$1,365,596,280	$1,488,792,561	$1,774,209,472	$770,563,676
	Other Benefits of ESP (Per Stipulation) [f]				
13	Economic Development	$1,150,000	$0	$0	$0
14	Weatherization/Fuel Fund	1,700,000	-	-	-
15	*Total Other Quantifiable Unconditional Benefits*	$2,850,000	$0	$0	$0
16	Present Value [g] of MRO Revenue	$4,586,339,265			
17	Present Value [g] of ESP Revenue	$4,524,279,806			
18	Net Benefit of ESP to Customers (ESP v. MRO)	$62,059,459			
	Other Assumptions				
19	Projected Total Retail Sales (MWh) [h]	20,473,777	20,810,354	21,177,162	8,664,268
20	Projected Total PIPP Sales (MWh) [i]	297,409	302,298	307,627	125,860

Notes: [a] The table below includes only quantifiable benefits. See Supplemental Testimony of Julia S. Janson for other benefits of the ESP Stipulation filed on October 24, 2011

[b] *As shown in the Direct Testimony of Judah L. Rose, Exhibit B.*

[c] As shown in the Direct Testimony of Judah L. Rose, Exhibit BB.

[d] Per Stipulation, Rider ESSC set at $110 million per year, subject to true-up.

[e] Per Stipulation, PIPP Discount is 5% of Residential PTC, excluding AER-R, (i.e., Rider RC+Rider RE+Rider SCR+Rider RTO).

[f] Includes shareholder contributions to various entities per Stipulation. Stipulation provides for additional funding for years after 2012 subject to meeting earnings thresholds for Duke Energy Ohio. Only 2012 amounts are shown as these are the only contribution: that are guaranteed per the Stipulation.

[g] Discounted at weighted-average cost of capital as shown in Attachment WDW-1 of Direct Testimony of William Don Wathen Jr.

[h] Projected MWh sales, at the meter, as shown in Attachment WDW-2 of Direct Testimony of William Don Wathen Jr.

[i] Current PIPP MWh sales escalated at overall growth in load.

Duke Energy Ohio
Rate Design Worksheet (Residential Classes)

	Jan '12-Dec '12	Jan '13-Dec '13	Jan '14-Dec '14	Jan '15-May '15
Rider RC				
Summer: First 1,000 kWh	$0.011961	$0.009949	$0.020238	$0.013258
Summer: Over 1,000 kWh	0.015893	0.013220	0.026891	0.017617
Winter: First 1,000 kWh	0.011961	0.009949	0.020238	0.013258
Winter: Over 1,000 kWh	0.002760	0.002296	0.004669	0.003059
Rider RE				
Summer: First 1,000 kWh	$0.061469	$0.071962	$0.079937	$0.079937
Summer: Over 1,000 kWh	0.073135	0.085620	0.095108	0.095108
Winter: First 1,000 kWh	0.061469	0.071962	0.079937	0.079937
Winter: Over 1,000 kWh	0.034168	0.040001	0.044434	0.044434
Rider SCR				
All kWh	$0.000000	$0.000000	$0.000000	$0.000000
Rider RTO				
All kWh	$0.000000	$0.000000	$0.000000	$0.000000
Total RS Price-to-Compare				
Summer: First 1,000 kWh	$0.073430	$0.081912	$0.100176	$0.093195
Summer: Over 1,000 kWh	0.089028	0.098840	0.122000	0.112725
Winter: First 1,000 kWh	0.073430	0.081912	0.100176	0.093195
Winter: Over 1,000 kWh	0.036928	0.042297	0.049104	0.047493
Total RS Billing Determinants				
Summer: First 1,000 kWh	1,817,099,832	1,846,971,898	1,879,527,042	768,975,843
Summer: Over 1,000 kWh	936,108,126	951,497,200	968,268,504	396,150,240
Winter: First 1,000 kWh	3,187,489,838	3,239,890,319	3,296,997,357	1,348,909,202
Winter: Over 1,000 kWh	1,145,637,349	1,164,470,961	1,184,996,190	484,820,608
Total kWh for RS	7,086,335,145	7,202,830,378	7,329,789,093	2,998,855,894
Total Residential ESP Revenue	$493,132,687	$559,972,553	$694,877,649	$265,058,770
Average Residential ESP Rate	$0.069589	$0.077743	$0.094802	$0.088387
PIPP Discount (@ 5%)	($0.003479)	($0.003887)	($0.004740)	($0.004419)

REDACTED

REDACTED

REDACTED

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Duke Energy Ohio, Inc.	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	End of 2011/Q4

Exhibit JAL-9

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Account 221 - First Mortgage Bonds		
2			
3	Ohio Air Quality Development 1995 Series A	42,000,000	272,300
4			149,265 D
5	Ohio Air Quality Development 1995 Series B	42,000,000	272,300
6			149,265 D
7	Ohio Air Quality Development 2002 Series A	42,000,000	1,245,167
8			
9	Ohio Air Quality Development 2002 Series B	42,000,000	1,245,167
10			
11	Ohio Air Quality Development Revenue Refunding 2007 Series A	25,300,000	298,823
12			
13	Ohio Water Development 2007 Revenue Refunding Series A	21,400,000	327,212
14			
15	5.45% First Mortgage Bonds Due 2019	450,000,000	2,174,657
16			180,000 D
17	2.10% First Mortgage Bonds Due 2013	250,000,000	687,500
18			42,500 D
19	Ohio Air Quality Development 2004 Series A	47,000,000	799,672
20			
21	Ohio Air Quality Development 2004 Series B	47,000,000	799,672
22			
23	Subtotal Account 221	1,008,700,000	8,643,500
24			
25	Account 222 & 223 - None		
26			
27	Account 224 - Notes Payable		
28			
29	6.9% Unsecured Debentures Due in 2025	150,000,000	4,839,412
30			975,000 D
31	5.70% Debentures Due in 2012	500,000,000	3,671,910
32			180,000 D
33	TOTAL	2,205,970,887	60,617,610

Name of Respondent Duke Energy Ohio, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q4

Exhibit JAL-9

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
09/01/95	09/01/30	09/01/95	09/01/30	42,000,000	233,577	3
						4
09/01/95	09/01/30	09/01/95	09/01/30	42,000,000	196,640	5
						6
09/10/02	09/01/37	09/10/02	09/01/37	42,000,000	541,327	7
						8
09/10/02	09/01/37	09/10/02	09/01/37	42,000,000	352,671	9
						10
10/11/07	01/01/24	10/11/07	01/01/24	25,300,000	202,042	11
						12
10/11/07	01/01/24	10/11/07	01/01/24	21,400,000	164,155	13
						14
03/23/09	04/01/19	03/23/09	04/01/19	450,000,000	24,525,000	15
						16
12/14/09	06/15/13	12/14/09	06/15/13	250,000,000	5,250,000	17
						18
11/10/04	11/01/39	11/18/04	11/01/39	47,000,000	547,953	19
						20
11/10/04	11/01/39	11/18/04	11/01/39	47,000,000	547,032	21
						22
				1,008,700,000	32,560,397	23
						24
						25
						26
						27
						28
06/01/95	06/01/25	06/01/95	06/01/25	150,000,000	10,350,000	29
						30
09/23/02	09/15/12	09/23/02	09/15/12	500,000,000	28,500,000	31
						32
				2,212,629,742	95,013,265	33

Exhibit JAL-10

DUKE ENERGY OHIO, INC.

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

	Years Ended December 31,		
(in millions)	**2012**	**2011**	**2010**
Operating Revenues			
Regulated electric	$ **1,386**	$ 1,518	$ 1,823
Non-regulated electric and other	**1,295**	1,105	885
Regulated natural gas	**471**	558	621
Total operating revenues	**3,152**	3,181	3,329
Operating Expenses			
Fuel used in electric generation and purchased power - regulated	**475**	380	490
Fuel used in electric generation and purchased power - non-regulated	**832**	653	465
Cost of natural gas	**142**	209	269
Operation, maintenance and other	**797**	885	836
Depreciation and amortization	**338**	335	400
Property and other taxes	**224**	260	260
Goodwill and other impairment charges	**2**	89	837
Total operating expenses	**2,810**	2,811	3,557
Gains on Sales of Other Assets and Other, net	**7**	5	3
Operating Income (Loss)	**349**	375	(225)
Other Income and Expenses, net	**13**	19	25
Interest Expense	**89**	104	109
Income (Loss) Before Income Taxes	**273**	290	(309)
Income Tax Expense	**98**	96	132
Net Income (Loss)	**175**	194	(441)
Other Comprehensive Income (Loss), net of tax			
Reclassification from earnings into cash flow hedges[a]	**—**	—	(1)
Pension and OPEB adjustments[b]	**27**	(6)	8
Comprehensive Income (Loss)	$ **202**	$ 188	$ (434)

(a) Net of $1 million tax benefit in 2010.

(b) Net of $8 million tax expense in 2012, insignificant tax expense in 2011 and $4 million tax expense in 2010.

See Notes to Consolidated Financial Statements

Exhibit JAL-10

DUKE ENERGY OHIO, INC.
CONSOLIDATED BALANCE SHEETS

(in millions)		December 31, 2012		December 31, 2011
ASSETS				
Current Assets				
Cash and cash equivalents	**$**	**31**	$	99
Receivables (net of allowance for doubtful accounts of $2 at December 31, 2012and $16 at December 31, 2011)		**108**		137
Receivables from affiliated companies		**82**		143
Notes receivable from affiliated companies		**1**		401
Inventory		**227**		243
Other		**267**		220
Total current assets		**716**		1,243
Investments and Other Assets				
Goodwill		**921**		921
Intangibles, net		**129**		143
Other		**75**		58
Total investments and other assets		**1,125**		1,122
Property, Plant and Equipment				
Cost		**10,824**		10,632
Accumulated depreciation and amortization		**(2,698)**		(2,594)
Net property, plant and equipment		**8,126**		8,038
Regulatory Assets and Deferred Debits				
Regulatory assets		**579**		520
Other		**14**		16
Total regulatory assets and deferred debits		**593**		536
Total Assets	**$**	**10,560**	$	10,939
LIABILITIES AND COMMON STOCKHOLDER'S EQUITY				
Current Liabilities				
Accounts payable	**$**	**318**	$	318
Accounts payable to affiliated companies		**62**		84
Notes payable to affiliated companies		**245**		—
Taxes accrued		**159**		180
Interest accrued		**14**		23
Current maturities of long-term debt		**261**		507
Other		**126**		122
Total current liabilities		**1,185**		1,234
Long-term Debt		**1,736**		2,048
Deferred Credits and Other Liabilities				
Deferred income taxes		**1,853**		1,853
Investment tax credits		**6**		8
Accrued pension and other post-retirement benefit costs		**157**		147
Asset retirement obligations		**28**		27
Regulatory liabilities		**254**		273
Other		**175**		182
Total deferred credits and other liabilities		**2,473**		2,490
Commitments and Contingencies				
Common Stockholder's Equity				
Common stock, $8.50 par value, 120,000,000 shares authorized; 89,663,086 shares outstanding at December 31, 2012 and December 31, 2011		**762**		762
Additional paid-in capital		**4,882**		5,085
Accumulated deficit		**(477)**		(652)
Accumulated other comprehensive loss		**(1)**		(28)
Total common stockholder's equity		**5,166**		5,167
Total Liabilities and Common Stockholder's Equity	**$**	**10,560**	$	10,939

See Notes to Consolidated Financial Statements

Exhibit JAL-10

DUKE ENERGY OHIO, INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
(in millions)	**2012**	**2011**	**2010**
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income (loss)	**$ 175**	$ 194	$ (441)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization	**342**	338	403
Gains on sales of other assets and other, net	**(7)**	(5)	(3)
Impairment charges	**2**	89	837
Deferred income taxes	**61**	190	17
Accrued pension and other post-retirement benefit costs	**11**	14	12
Contributions to qualified pension plans	**—**	(48)	(45)
(Increase) decrease in			
Net realized and unrealized mark-to-market and hedging transactions	**(5)**	(8)	(18)
Receivables	**29**	10	191
Receivables from affiliated companies	**61**	98	(221)
Inventory	**15**	11	15
Other current assets	**(62)**	(24)	71
Increase (decrease) in			
Accounts payable	**5**	(33)	87
Accounts payable to affiliated companies	**(22)**	1	(108)
Taxes accrued	**(24)**	8	25
Other current liabilities	**(21)**	(3)	6
Other assets	**—**	(61)	42
Other liabilities	**(116)**	47	(15)
Net cash provided by operating activities	**444**	818	855
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	**(514)**	(499)	(446)
Net proceeds from the sales of other assets	**82**	—	—
Notes receivable from affiliated companies	**400**	79	(296)
Change in restricted cash	**—**	(26)	—
Other	**6**	(3)	2
Net cash used in investing activities	**(26)**	(449)	(740)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from the issuance of long-term debt	**—**	—	34
Payments for the redemption of long-term debt	**(556)**	(9)	(36)
Notes payable and commercial paper	**—**	—	(12)
Notes payable to affiliated companies	**245**	—	—
Dividends to parent	**(175)**	(485)	—
Other	**—**	(4)	—
Net cash used in financing activities	**(486)**	(498)	(14)
Net (decrease) increase in cash and cash equivalents	**(68)**	(129)	101
Cash and cash equivalents at beginning of period	**99**	228	127
Cash and cash equivalents at end of period	**$ 31**	$ 99	$ 228
Supplemental Disclosures:			
Cash paid for interest, net of amount capitalized	**$ 93**	$ 100	$ 108
Cash paid (received) for income taxes	**$ 18**	$ (102)	$ 114
Significant non-cash transactions:			
Accrued capital expenditures	**$ 31**	$ 43	$ 40
Transfer of Vermillion Generating Station to Duke Energy Indiana	**$ 28**	$ —	$ —

See Notes to Consolidated Financial Statements

	Year Ended December 31, 2011				
(in millions)	**Franchised Electric**	**Total Reportable Segment**	**Other**	**Eliminations**	**Total**
Unaffiliated revenues[a]	$ 8,936	$ 8,936	$ 12	$ —	$ 8,948
Affiliated revenues	3	3	—	(3)	—
Total revenues	$ 8,939	$ 8,939	$ 12	$ (3)	$ 8,948
Interest expense	$ 423	$ 423	$ 324	$ (22)	$ 725
Depreciation and amortization	683	683	18	—	701
Income tax expense (benefit)	436	436	(113)	—	323
Segment income[a][b]	853	853	(273)	—	580
Add back noncontrolling interest component					7
Income from discontinued operations, net of tax					(5)
Net income					582
Capital investment expenditures and acquisitions	2,239	2,239	17	—	2,256
Segment assets	34,166	34,166	765	—	34,931

(a) Franchised Electric recorded a $173 million charge, net of tax of $115 million, for the amount to be refunded to customers through the fuel clause in accordance with the FPSC's 2012 settlement agreement. See Note 4 for additional information.
(b) Other includes after-tax costs to achieve the merger with Duke Energy of $33 million, net of tax of $22 million. See Note 2 for additional information.

	Year Ended December 31, 2010				
(in millions)	**Franchised Electric**	**Total Reportable Segment**	**Other**	**Eliminations**	**Total**
Unaffiliated revenues	$ 10,207	$ 10,207	$ 16	$ —	$ 10,223
Affiliated revenues	2	2	—	(2)	—
Total revenues	$ 10,209	$ 10,209	$ 16	$ (2)	$ 10,223
Interest expense	$ 444	$ 444	$ 332	$ (29)	$ 747
Depreciation and amortization	905	905	15		920
Income tax expense (benefit)	627	627	(88)		539
Segment income	1,045	1,045	(185)	—	860
Add back noncontrolling interest component					7
Income from discontinued operations, net of tax					(4)
Net income					863
Capital investment expenditures and acquisitions	2,437	2,437	32	(24)	2,445
Segment assets	32,475	32,475	450	(39)	32,886

Duke Energy Ohio

Duke Energy Ohio has two reportable operating segments, Franchised Electric and Gas and Commercial Power.

Franchised Electric and Gas transmits and distributes electricity in southwestern Ohio and generates, transmits, distributes and sells electricity in northern Kentucky. Franchised Electric and Gas also transports and sells natural gas in southwestern Ohio and northern Kentucky. It conducts operations primarily through Duke Energy Ohio and its wholly owned subsidiary, Duke Energy Kentucky.

Commercial Power owns, operates and manages power plants and engages in the wholesale marketing and procurement of electric power, fuel and emission allowances related to these plants, as well as other contractual positions. Duke Energy Ohio's Commercial Power reportable operating segment does not include the operations of DEGS or Duke Energy Retail, which are included in the Commercial Power reportable operating segment at Duke Energy.

The remainder of Duke Energy Ohio's operations is presented as Other. While it is not considered an operating segment, Other primarily includes certain governance costs allocated by its parent, Duke Energy. See Note 14 for additional information. All of Duke Energy Ohio's revenues are generated domestically and its long-lived assets are all in the U.S.

Business Segment Data

	Year Ended December 31, 2012					
(in millions)	Franchised Electric and Gas	Commercial Power	Total Reportable Segments	Other	Eliminations	Consolidated Total
Unaffiliated revenues[(a)]	$ 1,745	$ 1,407	$ 3,152	$ —	$ —	$ 3,152
Intersegment revenues	1	51	52	—	(52)	—
Total revenues	$ 1,746	$ 1,458	$ 3,204	$ —	$ (52)	$ 3,152
Interest expense	$ 61	$ 28	$ 89	$ —	$ —	$ 89
Depreciation and amortization	179	159	338	—	—	338
Income tax expense (benefit)	91	25	116	(18)	—	98
Segment income	159	50	209	(34)	—	175
Net income						175
Capital expenditures	427	87	514	—	—	514
Segment assets	6,434	4,175	10,609	117	(166)	10,560

(a) Duke Energy Ohio earned approximately 36% of its consolidated operating revenues from PJM Settlements, Inc. in 2012, all of which is included in the Commercial Power segment. These revenues relate to the sale of capacity and electricity from Commercial Power's non-regulated generation assets.

	Year Ended December 31, 2011					
(in millions)	Franchised Electric and Gas	Commercial Power	Total Reportable Segments	Other	Eliminations	Consolidated Total
Unaffiliated revenues[(a)]	$ 1,474	$ 1,707	$ 3,181	$ —	$ —	$ 3,181
Intersegment revenues	—	4	4	—	(4)	—
Total revenues	$ 1,474	$ 1,711	$ 3,185	$ —	$ (4)	$ 3,181
Interest expense	$ 68	$ 36	$ 104	$ —	$ —	$ 104
Depreciation and amortization	168	167	335	—	—	335
Income tax expense (benefit)	98	6	104	(8)	—	96
Segment income[(b)]	133	78	211	(17)	—	194
Net income						194
Capital expenditures	375	124	499	—	—	499
Segment assets	6,293	4,740	11,033	259	(353)	10,939

(a) Duke Energy Ohio earned approximately 24% of its consolidated operating revenues from PJM Interconnection, LLC (PJM) in 2011, all of which is included in the Commercial Power segment. These revenues relate to the sale of capacity and electricity from Commercial Power's nonregulated generation assets.

(b) Commercial Power recorded an after-tax impairment charge of $51 million, net of tax of $28 million, during the year ended December 31, 2011, to write-down the carrying value of certain emission allowances. See Note 12 for additional information.

	Year Ended December 31, 2010					
(in millions)	Franchised Electric and Gas	Commercial Power	Total Reportable Segments	Other	Eliminations	Consolidated Total
Unaffiliated revenues[(a)]	$ 1,623	$ 1,706	$ 3,329	$ —	$ —	$ 3,329
Intersegment revenues	—	5	5	—	(5)	—
Total revenues	$ 1,623	$ 1,711	$ 3,334	$ —	$ (5)	$ 3,329
Interest expense	$ 68	$ 41	$ 109	—	$ —	$ 109
Depreciation and amortization	226	174	400	—	—	400
Income tax expense (benefit)	106	40	146	(14)	—	132
Segment loss[(b)(c)]	(61)	(361)	(422)	(19)	—	(441)
Net loss						(441)
Capital expenditures	353	93	446	—	—	446
Segment assets	6,258	4,821	11,079	192	(247)	11,024

(a) Duke Energy Ohio earned approximately 13% of its consolidated operating revenues from PJM in 2010, all of which is included in the Commercial Power segment. These revenues relate to the sale of capacity and electricity from Commercial Power's nonregulated generation assets.

(b) Franchised Electric and Gas recorded an impairment charge of $216 million related to the Ohio Transmission and Distribution reporting unit. This impairment charge was not applicable to Duke Energy as this reporting unit has a lower carrying value at Duke Energy.

(c) Commercial Power recorded impairment charges of $621 million, which consisted of a $461 million goodwill impairment charge associated with the nonregulated Midwest generation operations and a $102 million charge, net of tax of $58 million, to write-down the value of certain nonregulated Midwest generating assets and emission allowances primarily associated with these generation assets.

Exhibit JAL-12

STANDARD
&POOR'S

Standard & Poor's Research

Research Update:

Duke Energy Corp. Rating Lowered To 'BBB+' From 'A-'; Progress Energy Inc. 'BBB+' Rating Affirmed; Outlook Is Negative

Primary Credit Analyst:
Dimitri Nikas, New York (1) 212-438-7807; dimitri_nikas@standardandpoors.com

Secondary Contact:
Gabe Grosberg, New York (1) 212-438-6043; gabe_grosberg@standardandpoors.com

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Research Update:

Duke Energy Corp. Rating Lowered To 'BBB+' From 'A-'; Progress Energy Inc. 'BBB+' Rating Affirmed; Outlook Is Negative

Overview

- Although the Duke Energy Corp. board of directors claimed a good faith exercise of its fiduciary duty in appointing a new CEO following the close of the merger with Progress Energy Inc., we view the lack of transparency associated with this process and with some board members--and which resulted in regulatory hearings and investigations in North Carolina--as significantly heightening regulatory risk for Duke Energy and weakening its consolidated business risk profile.
- We are lowering our corporate credit ratings on Duke Energy and its subsidiaries to 'BBB+' from 'A-' and are affirming our 'A-2' short-term rating on Duke Energy. We are removing the ratings from CreditWatch with negative implications.
- We are affirming our corporate credit rating on Progress Energy and its subsidiaries at 'BBB+' and are affirming our 'A-2' short-term rating. We are removing the ratings from CreditWatch with developing implications.
- The negative outlook on Duke Energy and its subsidiaries reflects the potential for lower ratings over the next 12 to 18 months if the company fails to deal with increased regulatory risk in North Carolina and Florida and to effectively manage the integration of the two companies.

(Watch the related CreditMatters TV segment titled, "Duke Energy: What Sparked Standard & Poor's Rating Actions," dated July 27, 2012.)

Rating Action

On July 25, 2012, Standard & Poor's Ratings Services lowered its corporate credit ratings on Duke Energy Corp. and its subsidiaries, Duke Energy Carolinas LLC, Duke Energy Ohio Inc., Duke Energy Indiana Inc., and Duke Energy Kentucky Inc., to 'BBB+' from 'A-'. We lowered the rating on Duke Energy's senior unsecured debt to 'BBB' from 'BBB+' and lowered the rating on Duke Energy Kentucky's senior unsecured debt to 'BBB+' from 'A-'. We affirmed the ratings on first-mortgage bonds of Duke Energy Carolinas, Duke Energy Ohio, and Duke Energy Indiana at 'A' and we affirmed the 'A-2' short-term ratings on Duke Energy. We removed the ratings from CreditWatch, where we placed them with negative implications on July 3, 2012.

At the same time, we affirmed the 'BBB+' corporate credit ratings on Progress Energy Inc. and its subsidiaries, Progress Energy Carolinas Inc. and Progress Energy Florida Inc. We also affirmed the 'BBB' rating on Progress Energy's senior unsecured debt and the 'A' ratings on first mortgage bonds of Progress Energy Carolinas and Progress Energy Florida. In addition, we affirmed the 'A-2' short-term ratings on Progress Energy and its subsidiaries. We removed the ratings from CreditWatch, where we placed them with developing implications on July 3, 2012.

Following the close of the merger with Duke Energy, Progress Energy is now a wholly owned subsidiary of Duke Energy.

The outlook on the ratings on Duke Energy and all its subsidiaries is negative.

Rationale

The ratings downgrade on Duke Energy and its subsidiaries stems from our view that abrupt leadership changes at the company have heightened regulatory risk in North Carolina and likely in Florida, significantly weakening the company's consolidated "excellent" business risk profile under our criteria. Our assessment of business risk incorporates the impact of the unexpected change in management on the company's regulatory relations (but not the actual change itself) and our view that the company may not be able to realize timely and constructive regulatory outcomes in North Carolina and Florida, two of its largest jurisdictions. In North Carolina, Duke Energy is preparing to file for two major rate-case increases and in Florida it needs to address the status of the Crystal River 3 nuclear plant, which has been out of service since August 2009. These concerns are compounded by the manifestly poor risk management that "legacy" Duke Energy demonstrated with its Edwardsport project in Indiana.

Following the unexpected change in CEO upon the close of Duke Energy's merger with Progress Energy, the North Carolina Utilities Commission (NCUC) initiated hearings and an investigation into the change in management. We believe the decision to change the CEO immediately after his appointment was a foregone conclusion. While an inability to act decisively is often an attribute of poor governance, in our opinion circumstances such as these are not a manifestation of good governance. What we believe to be deficient governance processes are combined with the lack of transparency on key information--which has become evident in the steps leading up to the merger of Progress and Duke. As a result, we think that management and the board have a journey ahead to restore their credibility with regulators and in the marketplace.

We will continue to monitor how the company's board and executive management navigate these issues, including CEO succession planning, the impact of any further executive or board departures, combining the two corporate cultures in a cohesive fashion to realize expected synergies, and assess the impact of changes in the regulatory environment.

Duke Energy's "excellent" business risk profile accounts for the benefits of its large and diverse U.S. regulated utility operations that serve more than 7 million customers across six states. These benefits are offset by several challenges the company faces as well as the risk introduced by its nonregulated operations, which include a largely uncontracted merchant generation fleet in the U.S. Midwest and merchant generation operations in Central and South America.

The regulated utility subsidiaries operate under generally credit-supportive regulatory environments that provide for slightly below-average returns but have timely recovery of fuel and other variable costs. The utility operations benefit from operating, regulatory, and economic diversity in service territories that range from average to attractive and span six states. Duke Energy's regulated generation operations have high availability and capacity utilization factors and rates that are competitive for the regions of operations. At the same time, Duke Energy's capital spending program is large, totaling between $6 billion and $6.5 billion per year through 2015. The capital spending program could increase somewhat to address operational issues at some of Progress Energy's nuclear power plants. Since about 90% of that planned capital spending is for the regulated operations, Duke Energy's regulated utilities will need regular rate relief to recover the invested capital in a timely manner while still preserving the overall "significant" financial risk profile. As a result, ineffective management of regulatory risk that leads to detrimental rate-case outcomes will further weaken the consolidated business risk profile and move it to the "strong" category. Even though recent rate-case outcomes in North Carolina and South Carolina were supportive and established a constructive beginning to Duke's multiyear effort to place several large generating stations in rate base, this pattern could erode as a result of the recent change in management and subsequent NCUC investigation which could delay important future rate-case filings and the associated rate increases, leading to a weaker financial risk profile in the near to intermediate term.

Progress Energy Florida's biggest challenge during 2012 will be to reach a conclusion regarding the repair or retirement of the Crystal River 3 nuclear plant that encountered significant structural problems and has been off-line since 2009. The company reached a settlement agreement with various intervenors, that the Florida Public Service Commission subsequently approved, which provides it with an effective framework to make prudent decisions regarding the plant. However, the change in management at Duke Energy combined with the short time frame remaining to make decisions without incurring additional financial burdens and exposure poses significant risks. The company may find it difficult to address these issues in a constructive manner while still preserving satisfactory regulatory relations. Duke Energy's decision regarding Crystal River 3 is also complicated by the apparent lack of progress and clarity in its negotiations with its insurance provider. Progress Energy Florida's proposal to repair the unit instead of retiring it could take until 2014 to complete at a cost estimate of $900 million to $1.3 billion. Should the company opt to repair the plant, it runs the risk that upon completion of the repairs similar structural problems could re-surface, while any repairs that change the original licensing basis of the unit could require the Nuclear Regulatory Commission's approval.

In Indiana, the company's 618-megawatt (MW) Edwardsport integrated gasification combined cycle unit is currently completing construction. Significant cost increases at the project resulted in a settlement agreement with various intervenors that capped the total cost of the project at $2.6 billion and caused an impairment of about $400 million in the first quarter of 2012. This impairment was in addition to earlier impairments of $266 million. The settlement agreement mitigates the uncertainty surrounding Duke Energy Indiana's cost recovery for the plant, although even if the Indiana Utility Regulatory Commission renders a decision in a timely basis in late 2012, we don't expect recovery of the investment in Edwardsport to commence until mid-2013. In addition to receiving approval for the Edwardsport settlement, Duke Energy must also demonstrate satisfactory operation of the plant once construction is complete, which is the first of its kind in the industry and therefore carries significant risk.

Duke Energy Ohio's latest electric security plan (ESP) went into effect in January 2012 and expires in May 2015. Customer and margin losses experienced under the previous ESP due to greater competition and low market prices for generation in Ohio had eroded financial results and resulted in higher business risk in the state. The new ESP allows Duke Energy Ohio to collect $330 million over three years, which can help support the company's financial profile. As a result, Duke has managed to restore its ability to earn a stable and fair return on the bulk of its Ohio assets at least through 2015. The Midwest gas-fired assets that were never regulated now have a completely market-based orientation.

Standard & Poor's ascribes significantly higher business risk to Duke Energy's international operations due to the uncertainty of the local political and regulatory environments in the countries where it operates: Argentina, Brazil, Peru, and Saudi Arabia. The Latin American assets have been self-funding, although we discount cash flow from overseas operations in our analysis of Duke Energy's ability to service the U.S. rated debt. Any substantial capital spending at the international operations could have negative ratings implications, depending on the risk profile of the investments pursued. While Duke Energy is also planning to increase its renewable generation business, our expectation is that the company will finance such investments in a credit-neutral manner and under a model that minimizes market exposure risk through long-term contracts with suitable counterparties. Any substantial acceleration in the growth of this segment could also negatively affect ratings.

Duke's consolidated financial risk profile is "significant" under our criteria. Historical credit metrics have been steady despite large capital projects, benefiting from low debt leverage. We expect that the financial profile can be materially influenced by the timing of future rate-case filings as well as the company's ability to harvest the proposed cost savings, which are in addition to the $650 million cost savings guaranteed to the ratepayers of North and South Carolina over five years with an 18-month extension, if necessary. We expect adjusted debt leverage to range from 50% to 52%, and adjusted funds from operations (FFO) to total debt to be just over 18% over the next few years, assuming regulatory outcomes remain constructive.

Liquidity

The short-term rating on Duke Energy is 'A-2' and largely reflects the company's long-term corporate credit rating and our expectation of ongoing stable regulated utility operations that generate the bulk of cash flows. Duke's ability to absorb high-impact, low-probability events with limited need for refinancing, its flexibility to lower capital spending or sell assets, its sound bank relationships, its solid standing in credit markets, and generally prudent risk management further support our description of liquidity as "adequate" under our criteria.

Duke manages the liquidity needs of all its subsidiaries. We assess its liquidity as adequate based on the following factors and assumptions:

- We expect the company's liquidity sources (including FFO, and credit facility availability) over the next 12 months to exceed its uses by more than 1.2x. Debt maturities over the next year are manageable.
- Even if EBITDA declines by 20%, we believe net sources will be well in excess of liquidity requirements.
- The company has good relationships with its banks, in our assessment, and has a good standing in the credit markets.

Duke Energy and its subsidiaries have a total of about $6 billion in credit facilities expiring in November 2016; $2 billion of that amount became available upon the close of the merger with Progress Energy. The master credit facility contains sublimits of $1.75 billion for Duke Energy, $1.25 billion for Duke Energy Carolinas, $650 million for Duke Energy Ohio, $750 million for Duke Energy Indiana, $100 million for Duke Energy Kentucky, $750 million for Progress Energy Carolinas, and $750 million for Progress Energy Florida. Maturing long-term debt in the next 12 months totals about $1.8 billion after accounting for debt already refinanced in 2012.

In our analysis, based on information available as of Dec. 31, 2011, as updated for the new facility, we assumed liquidity of about $14 billion over the next 12 months, consisting of FFO, cash on hand, and availability under the credit facility. We estimate the company could use up to $10 billion during the same period for capital spending, debt maturities, and shareholder dividends.

Duke's credit agreement includes a financial covenant requiring a maximum consolidated debt-to-capitalization ratio of 65% for each borrower. All were compliant as of March 31, 2012.

Outlook

The negative outlook on Duke Energy and its subsidiaries reflects the potential for lower ratings over the next 12 to 18 months if the company fails to effectively address increased levels of regulatory risk in two of its largest jurisdictions, which would move the business risk profile to the "strong" category and at the same time lead to weaker credit protection measures. Our base-case projections for Duke Energy incorporate the possibility of delayed but constructive rate-case outcomes in North Carolina and credit-neutral regulatory developments in Florida regarding Crystal River 3. These factors are a floor for our expectations leading to adjusted FFO to total debt of about 18% and adjusted debt leverage of between 50% and 52% by 2014, which would support current ratings. However, if credit protection measures fall below expectations such that adjusted FFO to total debt is below 16% along with adjusted debt leverage that approaches 55% we will lower the corporate credit rating by one notch to 'BBB'. In light of pending operational challenges, we do not expect to assign a higher rating to Duke Energy in the intermediate term.

Related Criteria And Research

- Liquidity Descriptors For Global Corporate Issuers, Sept. 28, 2011
- Standard & Poor's Updates Its U.S. Utility Regulatory Assessments, March 12, 2010
- Business Risk/Financial Risk Matrix Expanded, May 27, 2009
- Analytical Methodology, April 15, 2008

Ratings List

Downgraded; CreditWatch/Outlook Action; Short-Term Ratings Affirmed

	To	From
Duke Energy Corp.		
Duke Energy Ohio Inc.		
Duke Energy Indiana Inc.		
Duke Energy Carolinas LLC		
Cinergy Corp.		
Corporate Credit Rating	BBB+/Negative/A-2	A-/Watch Neg/A-2

Downgraded; CreditWatch/Outlook Action

	To	From
Duke Energy Kentucky Inc.		
Corporate Credit Rating	BBB+/Negative/--	A-/Watch Neg/--

Ratings Affirmed; CreditWatch/Outlook Action/Recovery Ratings Unchanged

	To	From

Carolina Power & Light Co. d/b/a Progress Energy Carolinas Inc.		
Progress Energy Inc.		
Florida Power Corp. d/b/a Progress Energy Florida Inc.		
Corporate Credit Rating	BBB+/Negative/A-2	BBB+/Watch Dev/A-2
Florida Progress Corp.		
Corporate Credit Rating	BBB+/Negative/--	BBB+/Watch Dev/--
Duke Energy Corp.		
Commercial Paper	A-2	A-2/Watch Neg
Carolina Power & Light Co. d/b/a Progress Energy Carolinas Inc.		
Senior Secured	A	A/Watch Dev
Recovery Rating	1+	1+
Preferred Stock	BBB-	BBB-/Watch Dev
Commercial Paper	A-2	A-2/Watch Dev
Cinergy Corp.		
Commercial Paper	A-2	A-2/Watch Neg
Duke Energy Carolinas LLC		
Senior Secured	A	A/Watch Neg
Recovery Rating	1+	1+
Duke Energy Indiana Inc.		
Senior Secured	A	A/Watch Neg
Recovery Rating	1+	1+
Duke Energy Ohio Inc.		
Senior Secured	A	A/Watch Neg
Recovery Rating	1+	1+
FPC Capital I		
Preferred Stock	BBB-	BBB-/Watch Dev
Florida Power Corp. d/b/a Progress Energy Florida Inc.		
Senior Secured	A	A/Watch Dev
Recovery Rating	1+	1+
Senior Unsecured	BBB+	BBB+/Watch Dev
Preferred Stock	BBB-	BBB-/Watch Dev
Commercial Paper	A-2	A-2/Watch Dev
Progress Energy Inc.		
Senior Unsecured	BBB	BBB/Watch Dev
Commercial Paper	A-2	A-2/Watch Dev

Complete ratings information is available to subscribers of RatingsDirect on the Global Credit Portal at www.globalcreditportal.com. All ratings affected by this rating action can be found on Standard & Poor's public Web site at www.standardandpoors.com. Use the Ratings search box located in the left column.

Exhibit JAL-13

2014/2015 RPM Base Residual Auction Results

Table 5 – Generation, Demand Resources, and Energy Efficiency Resources Offered and Cleared Represented in Unforced Capacity MW

	RTO*						
Auction Results (all values in UCAP)**	**2008/2009**	**2009/2010**	**2010/2011**	**2011/2012**	**2012/2013**	**2013/2014**	**2014/2015**
Generation Offered	131,164.8	132,614.2	132,124.8	136,067.9	134,873.0	147,188.6	144,108.8
DR Offered	715.8	936.8	967.9	1,652.4	9,847.6	12,952.7	15,545.6
EE Offered	-	-	-	-	652.7	756.8	831.9
Total Offered	**131,880.6**	**133,551.0**	**133,092.7**	**137,720.3**	**145,373.3**	**160,898.1**	**160,486.3**
Generation Cleared	129,061.4	131,338.9	131,251.5	130,856.6	128,527.4	142,782.0	135,034.2
DR Cleared	536.2	892.9	939.0	1,364.9	7,047.2	9,281.9	14,118.4
EE Cleared	0.0	0.0	0.0	0.0	568.9	679.4	822.1
Total Cleared	**129,597.6**	**132,231.8**	**132,190.5**	**132,221.5**	**136,143.5**	**152,743.3**	**149,974.7**
Uncleared	2,283.0	1,319.2	902.2	5,498.8	9,229.8	8,154.8	10,511.6

* RTO numbers include all LDAs

** UCAP calculated using sell offer EFORd for Generation Resources. DR and EE UCAP values include appropriate FPR and DR Factor.

Table 6 contains a summary of capacity additions and reductions from the 2007/2008 Base Residual Auction to the 2014/2015 Base Residual Auction. A total of 4,170.3 MW of incrementally new capacity in PJM was available for the 2014/2015 Base Residual Auction. This incrementally new capacity includes new generation capacity resources, capacity upgrades to existing generation capacity resources, new demand resources, upgrades to existing demand resources, and new energy efficiency resources. The increase is partially offset by generation capacity derations to existing generation capacity resources to yield a net increase of 2,620.2 MW of installed capacity.

Table 6 also illustrates the total amount of resource additions and reductions over eight Delivery Years since the implementation of the RPM construct. Over the period covering the first seven RPM Base Residual Auctions, 13,164.8 MW of new generation capacity was added which was partially offset by 8,894.8 MW of capacity de-ratings or retirements over the same period. Additionally, 15,480.9 MW of new demand resources and 733.4 MW of new energy efficiency resources were offered in the 2014/2015 auction. The total net increase in installed capacity in PJM over the period of the last seven RPM auctions was 20,557.4 MW.

REDACTED

Duke Energy Ohio
Legacy Generation Assets
Return on Equity

Line	Description	2012	2013	2014
1	Adjusted Earnings Available for Common	[redacted]	[redacted]	[redacted]
2	Average Net Equity (excluding Goodwill)	[redacted]	[redacted]	[redacted]
3	Return on Equity	0.3%	2.7%	7.7%

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing *Testimony* was served this 26th day of March 2013, via e-mail, upon the parties below.

/s/ *James F. Lang*
One of the Attorneys for FirstEnergy Solutions Corp.

John.jones@puc.state.oh.us Steven.beeler@puc.state.oh.us Amy.Spiller@duke-energy.com Elizabeth.watts@duke-energy.com Jeanne.Kingery@duke-energy.com cmooney2@columbus.rr.com sam@mwncmh.com fdarr@mwncmh.com joliker@mwncmh.com mpritchard@mwncmh.com tobrien@bricker.com grady@occ.state.oh.us kern@occ.state.oh.us jkyler@BKLlawfirm.com dboehm@BKLlawfirm.com mkurtz@BKLlawfirm.com dhart@douglasehart.com Bojko@CarpenterLipps.com Mohler@CarpenterLipps.com mwarnock@bricker.com tsiwo@bricker.com lthompson@energy-strategies.com kcampbell@energy-strategies.com jejadwin@aep.com yalami@aep.com stnourse@aep.com mjsatterwhite@aep.com dstahl@eimerstahl.com tcraven@wausaupaper.com	mhpetricoff@vorys.com lkalepsclark@vorys.com smhoward@vorys.com Stephen.bennett@exeloncorp.com David.fein@constellation.com Cynthia.brady@constellation.com Judi.sobecki@DPLINC.com Randall.griffin@DPLINC.com Joseph.strines@DPLINC.com kosterkamp@ralaw.com BarthRoyer@aol.com Rdc_law@swbell.net Gary.A.Jeffries@dom.com