## BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of	)	
Ohio Power Company for Authority to	)	Case No. 13-2385-EL-SSO
Establish a Standard Service Offer	)	
Pursuant to §4928.143, Revised Code,	)	
in the Form of an Electric Security Plan.	)	
In the Matter of the Application of	)	
Ohio Power Company for Approval of	)	Case No. 13-2386-EL-AAM
Certain Accounting Authority.	)	

# DIRECT TESTIMONY OF KEVIN M. MURRAY ON BEHALF OF INDUSTRIAL ENERGY USERS-OHIO

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# DIRECT TESTIMONY OF KEVIN M. MURRAY ON BEHALF OF INDUSTRIAL ENERGY USERS-OHIO

#### 1 I. INTRODUCTION

- 2 Q1. Please state your name and business address.
- 3 A1. My name is Kevin M. Murray. My business address is 21 East State Street, 17<sup>th</sup>
- 4 Floor, Columbus, Ohio 43215-4228.
- 5 Q2. By whom are you employed and in what position?
- 6 A2. I am employed as a Technical Specialist by McNees Wallace & Nurick LLC
- 7 ("McNees") and serve as the Executive Director of the Industrial Energy
- 8 Users-Ohio ("IEU-Ohio"). I am providing testimony on behalf of IEU-Ohio.
- 9 Q3. Please describe your educational background.
- 10 A3. I graduated from the University of Cincinnati in 1982 with a Bachelor of Science
- 11 degree in Metallurgical Engineering.

#### Q4. Please describe your professional experience.

2 A4. I have been employed by McNees for 17 years where I focus on helping 3 IEU-Ohio members address issues that affect the price and availability of utility I have also been actively involved, on behalf of commercial and 4 services. 5 industrial customers, in the formation of regional transmission organizations ("RTOs") and the organization of regional electricity markets from both the 6 7 supply-side and demand-side perspective. I serve as an end-use customer sector representative as well as Vice Chair on the Midcontinent Independent 8 9 Transmission System Operator, Inc. ("MISO") Advisory Committee and I have 10 been actively involved in MISO working groups that focus on various issues since 11 1999. Prior to joining McNees, I was employed by the law firm of Kegler, Brown, Hill & Ritter ("KBH&R") in a similar capacity. Prior to joining KBH&R, I spent 12 12 years with The Timken Company, a specialty steel and roller bearing 13 14 manufacturer. While at The Timken Company, I worked within a group that 15 focused on meeting the electricity and natural gas requirements for facilities in 16 the United States. I also spent several years in supervisory positions within The 17 Timken Company's steelmaking operations.

# 18 Q5. Have you previously testified before the Public Utilities Commission of Ohio ("Commission")?

20 A5. Yes. The proceedings before the Commission in which I have submitted expert testimony are identified in Exhibit KMM-1.

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#### Q6. What is the purpose of your testimony?

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The purpose of my testimony is to: (1) describe Ohio Power Company's ("AEP-Ohio") proposed Purchased Power Agreement ("PPA") Rider, (2) compare AEP-Ohio's proposed electric security plan ("ESP") to the market rate offer ("MRO") alternative; and (3) review AEP-Ohio's proposal to rebundle network integration transmission service ("NITS") and other non-market based transmission charges and convert NITS charges and other non-market based transmission charges from a bypassable charge, which allows a shopping customer to obtain NITS from a competitive retail electric service ("CRES") provider, into a non-bypassable charge. Based on my evaluation of the proposed PPA Rider and for reasons provided in my testimony, I recommend that the proposed PPA Rider be excluded from any ESP that may be approved by the Commission. I also recommend the Commission find that AEP-Ohio's proposed third ESP (ESP III) is not more favorable than an MRO alternative if AEP-Ohio's PPA Rider is included in the ESP III. I also recommend that the Commission not accept AEP-Ohio's proposal to rebundle NITS and other nonmarket based transmission charges with distribution service and convert NITS charges and other non-market based transmission charges into a nonbypassable charge.

If the Commission adopts the recommended modifications to the ESP III contained in my testimony, as well as the testimony of IEU-Ohio witness Joseph Bowser, it is my opinion that such a modified ESP III would be more favorable in the aggregate than the MRO alternative. As importantly, the adoption of the

recommendations offered in my testimony and the testimony of Mr. Bowser will avoid authorizing additional non-bypassable charges that will act as a barrier to completing the so-called "transition to market." The existing and proposed nonbypassable charges have resulted and will continue to result in AEP-Ohio's customers paying significantly above-market charges that detract from the benefits customers would have otherwise been able to obtain through the exercise of their "customer choice" rights.

#### 8 II. HISTORY OF THIS PROCEEDING

A7.

#### Q7. What are the significant components of the proposed ESP III?

AEP-Ohio's ESP III has a three-year term from June 1, 2015 through May 31, 2018. However, AEP-Ohio's application states that AEP-Ohio is retaining the unilateral right at its sole option and discretion to terminate ESP III one year early by providing written notice to the Commission in the event of a: (1) substantive change in Ohio law affecting standard service offer ("SSO") obligations or SSO rate plan options; or (2) substantive change in federal law including changes in PJM Interconnection, L.L.C.'s ("PJM") tariff or market rules regarding capacity, energy or transmission pricing.

Under the proposed ESP III, AEP-Ohio would conduct a competitive bid to obtain 100% of the generation supply (energy, capacity and ancillary services) necessary to provide the SSO. However, the results of the proposed competitive bid do not identify all the generation-related implications of the proposed ESP III on shopping and non-shopping retail customers of AEP-Ohio.

While AEP-Ohio has transferred its ownership of generating assets to a non-regulated affiliate or other affiliated American Electric Power ("AEP") operating companies, AEP-Ohio sought and obtained Commission approval to retain its wholesale contractual entitlement to receive power pursuant to a purchased power agreement between AEP-Ohio, Ohio Valley Electric Corporation ("OVEC") and other electric utility signatories (termed Sponsoring Companies under the purchased power agreement). In this proceeding, AEP-Ohio has proposed a PPA Rider which would allow AEP-Ohio to charge or credit retail customers for the difference between the costs it incurs pursuant to its wholesale power purchase agreement with OVEC and the revenues it receives from liquidating its wholesale energy and capacity entitlements pursuant to the agreement through sales into the wholesale power markets operated by PJM.

Other aspects of the proposed ESP III include a proposal to implement a purchase of receivables ("POR") program with CRES providers that would be linked to a new rider in order to allow AEP-Ohio to collect any bad debt resulting from the implementation of the POR program.

The proposed ESP III also contains several new riders (on top of the many riders that are already in place). These include the North American Electric Reliability Corporation ("NERC") Compliance and Cybersecurity Rider, which is intended to allow AEP-Ohio to automatically collect from its distribution customers the cost of compliance with new regulations imposed for system reliability and security.

<sup>&</sup>lt;sup>1</sup> In the Matter of the Application of Ohio Power Company for Approval of Full Legal Corporate Separation and Amendment to its Corporate Separation Plan, Case No. 12-1126-EL-UNC, Finding and Order at 9 (December 4, 2013).

Additionally, AEP-Ohio has proposed the Sustained and Skilled Workforce Rider to recover the costs associated with training additional internal construction and line workers. AEP-Ohio has proposed to continue several current riders, including the Distribution Investment Rider ("DIR"), the Enhanced Service Reliability Rider ("ESRR"), the gridSMART® Rider and the Storm Damage Recovery Mechanism. AEP-Ohio has also proposed to continue the Residential Distribution Credit Rider ("RDCR") which is presently scheduled to expire on May 31, 2015.

Finally and as already discussed previously, AEP-Ohio has proposed to rebundle NITS and other non-market based transmission charges and collect NITS and other non-market based transmission costs through a non-bypassable charge.

#### III. PPA RIDER

#### Q8. What is the purpose of the proposed PPA Rider?

A8. AEP-Ohio has previously sought and obtained Commission approval of a modification to its corporate separation plan to allow AEP-Ohio to temporarily retain its generation supply entitlements under a wholesale power purchase agreement with OVEC.<sup>2</sup> I have attached a copy of the current power purchase agreement (the Amended and Restated Inter-Company Power Agreement dated as of September 10, 2010 or "ICPA") to my testimony as Exhibit KMM-2. The temporary retention of this wholesale generation supply contract and the related modification to its corporate separation plan was based upon AEP-Ohio's claim

<sup>&</sup>lt;sup>2</sup> AEP-Ohio is one of the joint owners of OVEC.

that AEP-Ohio was unable to obtain the required consents necessary to transfer the OVEC contract entitlements to its affiliate, AEP Generation Resources Inc. ("AEP Genco").<sup>3</sup> As part of its proposal to retain the OVEC contract, AEP-Ohio proposed to liquidate its entitlements under the supply contract with OVEC by selling the entitlements (energy, capacity and ancillary services) into the wholesale markets operated by PJM.

In this proceeding, AEP-Ohio has proposed the PPA Rider to either collect or credit, through a non-bypassable charge to shopping and non-shopping customers, the difference between the costs it incurs pursuant to the wholesale power purchase agreement with OVEC (as well as possibly other additional wholesale power purchase contracts) and the revenues AEP-Ohio receives by liquidating AEP-Ohio's contractual entitlements through sales into PJM's wholesale markets or through bilateral wholesale sales.

#### Q9. Should the Commission approve the PPA Rider?

A9. No. There are multiple reasons to justify not approving the PPA Rider. First, as I discuss in my testimony, the proposed PPA Rider is expected to add millions in costs to the proposed ESP III and the additional cost of the PPA Rider alone would cause the proposed ESP III to fail the more favorable in the aggregate test required for approval. Second, it is my understanding that the Commission's order authorizing modification of AEP-Ohio's corporate separation plan indicates that the modification was temporary until AEP-Ohio could transfer the OVEC

<sup>&</sup>lt;sup>3</sup> AEP Genco was created to assume ownership of some of the generating assets previously owned by AEP-Ohio.

generation supply entitlements and did not establish an ongoing opportunity for
AEP-Ohio to retain the OVEC generation supply entitlements or, in effect, use its
relationship with retail customers to supplement or participate in the financial
benefits AEP-Ohio may derive from holding the OVEC generation supply
entitlement. In this context, I would also note that it is my understanding that the
OVEC contract provides a clear path to accomplish the transfer of the OVEC
wholesale generation supply entitlements before the start of the proposed ESP III
and thereby eliminate the need for any deviation from the otherwise applicable
corporate separation requirements. Finally, the proposed PPA Rider would result
in a subsidy flowing to or from AEP-Ohio's noncompetitive retail electric service
distribution customers to a product or service other than retail service, a result
that is both contrary to the state's policies and, as I understand it, unlawful.

# Q10. What is your understanding of the duration of Commission's approval of AEP-Ohio's corporate separation plan modification?

A10. Although the Commission accepted AEP-Ohio's plan to liquidate its OVEC wholesale power purchase agreement in the wholesale market, it is my understanding that the Commission's authorization of AEP-Ohio's retention of the OVEC wholesale generation supply entitlements was temporary. In discussing the conditions imposed on retention of the OVEC entitlement, the Commission stated:

These conditions should apply during AEP Ohio's current ESP period and beyond, <u>until the OVEC contractual entitlements can be</u>

transferred to AEP Genco or otherwise divested, or until otherwise ordered by the Commission.<sup>4</sup>

#### Q11. What cost is AEP-Ohio expected to incur under the wholesale ICPA?

A11. It is my understanding that under the ICPA AEP-Ohio is billed on a cost-plus formula rate in accordance with the approvals provided by the Federal Energy Regulatory Commission ("FERC"). According to page 8 of the 2012 OVEC Annual Report, which is attached to my testimony as Exhibit KMM-3, "[t]he proceeds from the sale of power to the Sponsoring Companies are designed to be sufficient for OVEC to meet its operating expenses and fixed costs, as well as earn a return on equity before federal income taxes. In addition, the proceeds from power sales are designed to cover debt amortization and interest expense associated with financings. The Companies have continued and expect to continue to operate pursuant to the cost plus rate of return recovery provisions at least to June 30, 2040, the date of termination of the ICPA."

# Q12. Has AEP-Ohio estimated the revenues or credits it expects to collect through the PPA Rider during the term of the ESP III?

A12. Yes. In response to IEU-Ohio Interrogatory 2-1, AEP-Ohio produced three Excel spreadsheets<sup>5</sup> that model the expected wholesale revenue from the sales or liquidation of the OVEC entitlement as well as the expected costs of the wholesale generation supply. I have attached AEP-Ohio's response to IEU-Ohio

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<sup>&</sup>lt;sup>4</sup> In the Matter of the Application of Ohio Power Company for Approval of Full Legal Corporate Separation and Amendment to its Corporate Separation Plan, Case No. 12-1126-EL-UNC, Finding and Order at 9 (December 4, 2013) (emphasis added).

<sup>&</sup>lt;sup>5</sup> AEP-Ohio identified the Excel spreadsheets as IEU RPD 2-001 Competitively-Sensitive Confidential Attachment 1.xlsx, IEU RPD 2-001 Competitively-Sensitive Confidential Attachment 2.xlsx, and IEU RPD 2-001 Competitively-Sensitive Confidential Attachment 3.xlsx, respectively.

1	Interrogatory	2-1	as	Exhibit	KMM-4	to	my	testimony,	and	the	three	Excel
2	spreadsheets	(wh	ich	are con	fidential	) as	Exh	ibits KMM-5	. KMI	M-6 a	and KM	ИМ-7.

- Q13. What are AEP-Ohio's estimated revenues or credits it expects to collect through the PPA Rider during the term of the ESP III?
- A13. As shown on Exhibit KMM-5, AEP-Ohio projects to collect approximately \$52 million from retail customers through the non-bypassable PPA Rider during the term of the ESP III.
- 8 Q14. What is your understanding regarding the assumptions AEP-Ohio made in calculating these estimates?
  - A14. As is the case in any estimate of forward wholesale generation market sales and costs, it is my understanding that AEP-Ohio made numerous assumptions to develop its estimate. For example, the Office of the Ohio Consumers' Counsel ("OCC") requested, through Interrogatory 5-094 and 5-095, that AEP-Ohio provide a description of the data modeled and the data sources in the three Excel spreadsheets which I have attached to my testimony. I have included AEP-Ohio's response to those interrogatories as Exhibit KMM-8 and it illustrates the numerous assumptions associated with the estimation and modeling effort. However, a significant assumption made by AEP-Ohio, one that is specifically noted on Exhibit KMM-5, is that the annual wholesale demand charge to AEP-Ohio under the ICPA would be reduced by \$10 million per year to reflect "lean improvements/process optimization." The \$10 million per year reflects the portion of the reduced demand charges allocated to AEP-Ohio based upon its

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power participation ratio, which is 19.93%. In other words, the total assumed
reduction in annual OVEC wholesale demand charges reflected in AEP-Ohio's
estimate of the costs of the PPA Rider is more than \$50 million per year. Without
this assumed reduction in OVEC wholesale generation supply demand charges,
the impact of the PPA Rider during the term of ESP III would be much higher.
And, under the proposed PPA Rider, AEP-Ohio's shopping and non-shopping
customers take on all the risk of deviations between the assumed reduction in
OVEC wholesale demand charges and actual OVEC wholesale demand charges
that turn out to be higher than the level assumed by AEP-Ohio in its analysis.

Q15. Are, in your opinion, these assumed reductions in OVEC's annual wholesale generation supply demand charges likely to happen or certain to happen?

A15. No. The OCC requested AEP-Ohio, through an interrogatory, to identify whether OVEC or AEP-Ohio had committed to making these lean improvements/process changes or reducing the OVEC annual demand charges irrespective of whether the process improvements were actually achieved. I have attached AEP-Ohio's response to the OCC's interrogatory 11-272 as Exhibit KMM-9 (confidential) to my testimony. In all instances, AEP-Ohio's response was no.

In other words, if the lean improvements/process optimization fails to materialize, the PPA Rider will collect from AEP-Ohio retail distribution service customers, on a non-bypassable basis, \$30 million more or approximately \$82 million during the term of the ESP III. Based upon the information provided by AEP-Ohio, I believe

the \$82 million impact of the PPA Rider is a more realistic indication of the electric bill increasing effect of the proposed PPA Rider on AEP-Ohio's retail distribution service customers during the term of AEP-Ohio's proposed ESP III.

# 4 Q16. Are there any options you have identified and recommend the Commission adopt as an alternative to the PPA Rider?

Yes. AEP-Ohio has previously represented to the Commission that it was unable to obtain the required consent from the other parties to the ICPA in order to transfer the ICPA to AEP Genco. While this may be correct, it is my understanding that there are other transfer options under the ICPA. It is my understanding that Section 9.18 of the ICPA governs successors to and assignment of the ICPA. It is my understanding that Section 9.181 of ICPA requires written consent of the other signatory parties in order to assign the ICPA. However, it is also my understanding that Section 9.182 provides that notwithstanding the provisions of Section 9.181, the ICPA may be assigned to another Permitted Assignee,<sup>6</sup> so long as an assignment agreement in an acceptable form to the Corporation<sup>7</sup> has been executed. Further, it is my understanding that Section 9.183 also specifies that notwithstanding Section 9.181 "any Sponsoring Company shall be permitted to, subject to compliance with all of the requirements of this Section 9.183, assign all or part of its rights,

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A16.

<sup>&</sup>lt;sup>6</sup> It is my understanding that a Permitted Assignee is defined generally as a Sponsoring Company or Affiliate provided that a threshold credit rating is satisfied and the assignment does not trigger or cause a termination, default, loss or payment obligation under any security issued or agreement entered into prior to the assignment.

<sup>&</sup>lt;sup>7</sup> It is my understanding that this is defined as OVEC, Indiana-Kentucky Electric Corporation ("IKEC") and all other subsidiaries of OVEC.

1	title an	d interests	in,	and	obligations	under	this	Agreement	to	а	Third	Party
2	without	any further	acti	on by	y the Corpor	ation o	r the	other Spons	orir	ıg	Parties	s."

It is my understanding that a Third Party is defined under the ICPA as any person other than a Sponsoring Company or Affiliate.

It is my understanding that the additional compliance obligations required to assign the ICPA pursuant to Section 9.183 govern minimum creditworthiness requirements for the Third Party assignee, and a determination that the assignment would not trigger a default, termination, loss or payment obligation under any securities issued prior to the assignment.

Q17. Based on your understanding of the ICPA, are there any other notable provisions associated with the Third Party assignment options permitted pursuant to Section 9.183 of the ICPA?

A17. Yes. The subsections to Section 9.183 identify that if a signatory attempts to assign its contractual entitlements and obligations to a Third Party under the ICPA, that action triggers a right of first refusal option to the other Sponsoring Companies. It is my understanding that this option allows any Sponsoring Company or its Affiliate the first right to purchase the ICPA entitlements in place of assignment to a Third Party. The first right occurs when the Sponsoring Company or its Affiliate agree to terms of an Offer Notice that specifies the terms and conditions through which the Sponsoring Company or its Affiliate exercises its rights rather than allowing assignment to a Third Party. It is my understanding that if no Sponsoring Company or Affiliate exercises it rights to

purchase the entitlement, the signatory is permitted, pursuant to Section 9.183(e), to complete the assignment to a Third Party at no less than 92.5% of the purchase price specified in the Offer Notice.

Q18. Assuming your understanding of the ICPA provisions is correct, how might they affect AEP-Ohio's opportunity to complete the transfer of its OVEC wholesale generation supply entitlements?

Based on my understanding of these provisions of the ICPA, it is my opinion that A18. they may provide AEP-Ohio several opportunities to assign its ICPA wholesale generation supply entitlements and that they provide AEP-Ohio with the option to assign such entitlements to a Third Party without further action by the Sponsoring Companies.<sup>8</sup> Once the OVEC generation supply entitlements are transferred or assigned, the transferee or assignee would be able to bid the generation supply directly into the wholesale markets, use the supply to meet requirements under bilateral retail or wholesale contracts or engage in other commercial physical or financial transactions without consequence to AEP-Ohio's retail distribution service customers and in ways that would discontinue any ongoing need for AEP-Ohio to maintain a temporary corporate separation waiver. If, as AEP-Ohio claims, the ICPA is a valuable hedge against wholesale generation market exposure, it should not be difficult to find a Third Party willing to accept assignment of the ICPA. Additionally, if the ICPA is viewed by other Sponsoring Companies to be a valuable hedge against market exposure, competitive

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<sup>&</sup>lt;sup>8</sup> The Corporation is required to identify that the assignment will not trigger a default.

1 pressure would trigger these companies to consider exercising their right of first 2 refusal rather than allow assignment of the ICPA to a Third Party.

### 3 Q19. Are there any other reasons why the proposed PPA Rider should not be approved?

Yes. It is my understanding that Ohio's state electricity policy and Ohio law require that the Commission ensure "effective competition in the provision of retail electric service by avoiding anticompetitive subsidies flowing from a noncompetitive retail electric service to a competitive retail electric service or to a product or service other than retail electric service, and vice versa, including by prohibiting the recovery of any generation-related costs through distribution or transmission rates." AEP-Ohio's proposed PPA Rider is structured to provide a direct subsidy flowing to or from AEP-Ohio retail non-competitive distribution service customers and to or from a product or service other than retail electric service, in this case wholesale generation supply service available to AEP-Ohio pursuant to the ICPA. The PPA Rider causes such a subsidy payment from AEP-Ohio retail distribution customers when it results in a charge (the cost of the OVEC wholesale supply available to AEP-Ohio is in excess of the revenue resulting from liquidation in the wholesale markets). The PPA Rider is a subsidy to retail distribution customers when it results in a credit (the cost of the OVEC wholesale supply available to AEP-Ohio is less than the revenue resulting from liquidation in the wholesale markets). In either case, the result runs afoul of Ohio's pro-competitive policies and the law. I would also note that because the

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<sup>&</sup>lt;sup>9</sup> Section 4928.02(H), Revised Code.

proposed liquidation of the wholesale generation supply available to AEP-Ohio pursuant to the ICPA is, based on my understanding, a wholesale or generation sale for resale transaction which would be subject to the exclusive jurisdiction of FERC, the opportunity for the Commission to supervise or regulate the liquidation side of the proposed PPA Rider process may be limited to the extent it may exist at all.

Additionally, in those instances in which the PPA Rider would result in a charge and result in AEP-Ohio's retail distribution customers supplementing the revenue which AEP-Ohio receives from the wholesale generation supply liquidation process that is part of the proposed PPA Rider, AEP-Ohio's retail customers would be providing AEP-Ohio with the equivalent of additional generation-related It is my understanding that result is prohibited by the transition revenues. express terms of the Stipulation and Recommendation adopted to resolve AEP-Ohio's (or its predecessors') electric transition plan ("ETP") proceedings to implement 1999's Amended Substitute Senate Bill 3 ("SB 3"), as well as Ohio law, which requires that the collection of transition revenues terminate no later than the end of AEP-Ohio's market development period. It is also my understanding that the electric generation function is required to be "fully on its own in the competitive market" 10 and the Commission lacks the authority to authorize additional transition revenues or their equivalent.

Finally, the ICPA, in its present form, dates to 2003 when the U.S. Department of Energy ("DOE") elected to terminate its right to purchase a significant part of

<sup>10</sup> Section 4928.38, Revised Code.

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OVEC's wholesale generation supply. At the time, it is my understanding that the Sponsoring Companies agreed to pay their share of all of OVEC's costs resulting from the ownership, operation and maintenance of its generation and transmission facilities, except those costs that were paid by the DOE. exchange, the Sponsoring Companies were entitled to fractional shares of the output of the generating facility. The ICPA was amended in 2010 to extend the termination date from March 2026 to June 30, 2040 in part to allow OVEC the opportunity to refinance debt and to take advantage of more favorable interest rates. The decision to restructure the ICPA and assumed obligation, theretofore underwritten to a large extent by DOE, was freely undertaken at a point in time after Ohio had elected to restructure its electricity markets and subject generation to competition and after any opportunity to seek transition revenues terminated. It would be fundamentally unfair to require retail distribution customers to underwrite the financial consequences of generation-related business decisions made by AEP-Ohio since AEP-Ohio made this decision well after Ohio changed its laws to declare generation service competitive and to provide retail customers with the benefits of a competitive electric market.

# Q20. Can you summarize your recommendations on AEP-Ohio's proposed PPA Rider?

A20. Yes. The Commission should deny AEP-Ohio's request for authorization to include the proposed PPA Rider in ESP III. As discussed below, the fate of the proposed PPA Rider and the wholesale generation supply costs it would, if approved, impose of retail customers as part of an ESP is inextricably tied to the

1	question of whether the proposed ESP III is more favorable in the aggregate than
2	an MRO.

#### 3 IV. ESP VERSUS MRO TEST

- 4 Q21. What is your understanding regarding what the Commission must find before it can approve the proposed ESP III?
- A21. It is my understanding that the Commission must find that the proposed ESP III, including its pricing and all other terms and conditions, including any deferrals and the future recovery of deferrals, is more favorable in the aggregate as compared to the expected results under an MRO before it can approve the ESP III. It is also my understanding that AEP-Ohio bears the burden of proof to demonstrate the proposed ESP III is more favorable than an MRO.
- 12 Q22. Did AEP-Ohio evaluate whether the ESP III is more favorable in the aggregate than an MRO?
- 14 A22. Yes. AEP-Ohio witness William Allen testifies that the proposed ESP III is more
  15 favorable than an MRO. Mr. Allen testifies that because AEP-Ohio would be
  16 acquiring 100% of the commodity to provide the SSO through a competitive
  17 bidding process ("CBP") under either an ESP or an MRO, there is no quantifiable
  18 difference in commodity prices. Although there is no quantifiable difference in
  19 commodity prices between the proposed ESP III and an MRO, he concludes on
  20 page 5 of his written testimony, that because the proposed ESP III provides

1		\$44,064,000 in quantifiable benefits over the term of the ESP III and additional
2		non-quantifiable benefits, the proposed ESP III is more favorable than an MRO.
3	Q23.	What is the source of the \$44,064,000 in quantifiable benefits identified by
4		Mr. Allen?
5	A23.	The \$44,064,000 in quantifiable benefits is the result of AEP-Ohio's proposal to
6		extend the RDCR through May 31, 2018. This rider is presently scheduled to
7		expire on May 31, 2015.
8	Q24.	Do you disagree with Mr. Allen's assignment of \$44,064,000 in quantifiable
9		benefits resulting from extension of the RDCR?
10	A24.	No. However, as discussed in Mr. Allen's testimony, the benefits of the credit are
11		limited to the residential class. Additionally, as discussed later in my testimony,
12		there are some offsetting costs that Mr. Allen has failed to recognize in his
13		analysis.
14	Q25.	Do you agree that the generation supply cost would be the same under
15		either an ESP or MRO?
16	A25.	Yes, assuming you ignore the PPA Rider proposal which I discuss below.
17		Because AEP-Ohio will have divested all of its generating assets by June 1,
18		2015, I also agree with Mr. Allen's conclusion that the generation supply costs to
19		provide the SSO under either an ESP or MRO would be the same.

1	Q26.	Did AEP-Ohio identify any other quantifiable benefits of the proposed ESP
2		III?
3	A26.	No. In response to OCC Interrogatory 3-025, AEP-Ohio responded that it had
4		not identified any other quantifiable benefits. I have attached a copy of this
5		interrogatory and AEP-Ohio's response as Exhibit KMM-10.
6	Q27.	Has AEP-Ohio failed to recognize quantifiable costs associated with the
7		proposed ESP III?
8	A27.	Yes. AEP-Ohio has failed to recognize the costs associated with the proposed
9		PPA Rider which, based upon AEP-Ohio's own analysis, are expected to be
10		substantial over the three-year term of the ESP III.
11	Q28.	What is the appropriate treatment of the PPA Rider for the purpose of the
12		ESP versus MRO test?
13	A28.	Mr. Allen testifies that the PPA Rider would not exist under an MRO and I agree
13 14	A28.	Mr. Allen testifies that the PPA Rider would not exist under an MRO and I agree with Mr. Allen's conclusion. Therefore, there would be no cost (or benefit)
	A28.	
14	A28.	with Mr. Allen's conclusion. Therefore, there would be no cost (or benefit)
14 15	A28.	with Mr. Allen's conclusion. Therefore, there would be no cost (or benefit) associated with the proposed PPA Rider under an MRO. As discussed
14 15 16	A28.	with Mr. Allen's conclusion. Therefore, there would be no cost (or benefit) associated with the proposed PPA Rider under an MRO. As discussed previously in my testimony, I offer multiple reasons, independent of the ESP
14 15 16	A28.	with Mr. Allen's conclusion. Therefore, there would be no cost (or benefit) associated with the proposed PPA Rider under an MRO. As discussed previously in my testimony, I offer multiple reasons, independent of the ESP versus MRO test, why the proposed PPA Rider should not be approved.
14 15 16 17	A28.	with Mr. Allen's conclusion. Therefore, there would be no cost (or benefit) associated with the proposed PPA Rider under an MRO. As discussed previously in my testimony, I offer multiple reasons, independent of the ESP versus MRO test, why the proposed PPA Rider should not be approved. However, because AEP-Ohio has included the PPA Rider as a component of the

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1	Q29.	What are the c	uantifiable costs	or benefits of the	e proposed PPA Rider?
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- 2 A29. As discussed previously in my testimony, AEP-Ohio's own analysis concludes that the PPA Rider will collect approximately \$52 million in wholesale generation-3 related costs through non-bypassable distribution charges during the term of the 4 ESP III. As previously discussed, I believe AEP-Ohio's estimate of the 5 generation-related cost burden is significantly understated, and \$82 million is a 6 more realistic estimate of the generation-related costs that the proposed PPA 7 Rider would impose on consumers through non-bypassable distribution charges 8 during the term of the ESP III. 9
- 10 Q30. Now, moving to a different element of the proposed ESP, are there
  11 quantifiable costs and benefits associated with the DIR?
- A30. No. Mr. Allen's testimony could be read to imply there are, although he does not assign a specific dollar amount to the DIR quantitative benefit. Mr. Allen testifies that the DIR mechanism provides a streamlined approach to cost recovery and suggests that recovery of incremental distribution investment costs through a base rate case would result in higher costs to consumers.
- 17 Q31. To the extent Mr. Allen is asserting quantifiable benefits from the DIR, do
  18 you agree with Mr. Allen's views regarding the DIR?

19 A31. No.

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#### 1 Q32. Why are there no quantifiable benefits associated with the DIR?

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The Commission has previously considered a proposal substantively equivalent A32. to the proposed DIR and concluded the quantitative costs associated with recovery of incremental distribution investment through either a rider or a base rate case should be considered a "wash." Specifically, in Case No. 12-1230-EL-SSO [which involved a proposed ESP for the FirstEnergy Corporation ("FirstEnergy") operating companies], various parties advanced competing arguments on whether FirstEnergy's Delivery Capital Recovery Rider ("Rider DCR") should be considered a quantifiable benefit of the proposed ESP. Rider DCR would "provide the Companies with the opportunity to recover property taxes, commercial activity tax, and associated income taxes, and earn a return on and of plant-in-service associated with distribution, subtransmission, and general and intangible plant, including general plant from FirstEnergy Service Company that supports the Companies and was not included in the rate base determined in In re FirstEnergy, Case No. 07-551-EL-AIR, et al., Opinion and Order (January 21, 2009)."11 FirstEnergy (through the supporting testimony of FirstEnergy witness William Ridmann) argued that Rider DCR should be considered a quantifiable benefit of the proposed ESP. Conversely, the Commission Staff (through the supporting testimony of Robert Fortney) testified the costs of Rider DCR versus recovery through a traditional base rate proceeding should be considered a "wash."

<sup>&</sup>lt;sup>11</sup> In the Matter of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan, Case No. 12-1230-EL-SSO, Opinion and Order at 10 (July 18, 2012).

1		In its decision, the Commission agreed with the opinion of Staff witness Fortney
2		and removed the costs associated with Rider DCR from the quantitative ESP
3		versus MRO analysis. <sup>12</sup>
4		Given this precedent and the substantial similarities between FirstEnergy's Rider
5		DCR and the DIR, I recommend the Commission treat the DIR as a "wash" and
6		remove the DIR from the ESP versus MRO analysis.
7	Q33.	What are the quantifiable costs or benefits of the proposed ESP III?
8	A33.	Once the \$44 million in benefits of the RDCR over the term of the ESP III are
9		netted against the additional costs of the PPA Rider (which range from \$52
10		million to \$82 million over the term of the ESP III as previously discussed) and
11		the DIR is removed from the analysis, the quantifiable cost of the proposed ESP
12		III in excess of an MRO is between \$8 to \$38 million.
13	Q34.	Has AEP-Ohio identified any non-quantifiable benefits to support approval
14		of the proposed ESP III?
15	A34.	Yes. Mr. Allen testifies that there are non-quantifiable benefits associated with:
16		(1) the accelerated transition to competition; (2) the increased price stability
17		associated with the PPA Rider; and (3) the POR program.
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<sup>12</sup> *Id.* at 55-56.

1	Q35.	Do you agree that these elements of the proposed ESP III provide non-
2		quantifiable benefits?
3	A35.	No. I discuss below why the first two items identified in the answer to Question
4		34 do not provide any non-quantifiable benefits. IEU-Ohio witness Joseph
5		Bowser discusses in his testimony why the POR does not provide non-
6		quantifiable benefits.
7	Q36.	Why are there no non-quantifiable benefits associated with the accelerated
8		process to achieve full competition as discussed in Mr. Allen's testimony?
9	A36.	The commitment to source all generation necessary to serve the entire SSO load
10		through a CBP was made as part of the approval of AEP-Ohio's current ESP in
11		2012. Thus, there is no "accelerated" move to competition associated with the
12		proposed ESP III and hence there can be no non-quantifiable benefits even if
13		non-quantifiable benefits could be considered for purposes of conducting the
14		ESP versus MRO test.
15	Q37.	Has the Commission previously reached a similar conclusion?
16	A37.	Yes, that is my understanding.
17	Q38.	Can you describe your understanding of the Commission's decision and
18		the specific circumstances?
19	A38.	Yes. This also involved the Commission's decision on FirstEnergy's current ESP
20		approved in Case No. 12-1230-EL-ESP.

Although the specific facts differ, I believe they are similar enough to provide guidance in this proceeding. In Case No. 12-1230-EL-SSO, FirstEnergy argued that its decision to forego regional transmission expansion plan ("RTEP") costs should be considered a quantifiable benefit of the proposed ESP. Through the testimony of Commission Staff witness Robert Fortney, the Staff recommended that foregoing recovery of RTEP costs not be treated as a quantifiable benefit of the ESP because FirstEnergy had already agreed to forego recovery of RTEP costs in a prior proceeding. The Commission accepted the view of Commission Staff witness Fortney. 13

Because the commitment to source all generation necessary to serve the entire SSO load through a CBP was made as part of the approval of AEP-Ohio's current ESP, I recommend the Commission find it does not provide a nonquantifiable benefit to the proposed ESP III. I would also note that the PPA Rider proposal is, practically speaking, a proposal that would make an exception to the commitment to determine generation-related costs imposed on SSO customers through a CBP and would also increase the generation-related costs paid by shopping customers during the term of the ESP.

- Q39. Why are there no non-quantifiable benefits associated with the "rate stability" that Mr. Allen attributes to the PPA Rider in his testimony?
- The only stability provided by the PPA Rider is the stability provided AEP-Ohio 20 (as an equity owner in OVEC) through a guaranteed return of and on its

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<sup>&</sup>lt;sup>13</sup> *Id.* at 55.

generation investments funded by captive retail distribution customers through the PPA Rider. As proposed by AEP-Ohio, the PPA Rider provides no stability to any SSO or non-SSO customer at all because it is an unknown cost or credit that will vary in amount over the term of the proposed ESP III and the variation will be reflected in the charge that is periodically adjusted and reconciled as the PPA Rider is implemented along with the several other riders and adjustment mechanisms. The only guarantee for shopping and non-shopping retail customers provided by the PPA Rider is that their rates will remain unpredictable for the entire term of the ESP III. Indeed, for shopping customers who have selected fixed price offers from CRES providers, the proposed PPA Rider would add uncertainty and instability to their delivered price of electricity.

AEP-Ohio witness Dr. Chantale LaCasse testifies the design of the CBP is structured (both in terms of the timing, quantity of tranches, and bid term) to reduce exposure to market conditions at any one time.

If the true objective of the PPA Rider was to provide retail customers predictable rates, there would be a far easier, and stable, way to achieve this result. The Commission could direct the ESP III be modified to conduct a single, descending clock auction for all of the SSO generation supply necessary for the entire ESP III term or for a longer term, prior to the start of the ESP III, and eliminate the pricing uncertainty created by the PPA Rider to both SSO and shopping customers. That course of action would provide the ultimate level of pricing and revenue stability for non-shopping customers. The SSO generation rates would be known before the start of the ESP and stable for the entire ESP III term, and shopping

1	customers	would	not	face	the	unpredictability	and	extra	costs	that	they	will
2	experience	if the F										

For these reasons and assuming that non-quantifiable benefits are considered for purposes of conducting the ESP versus MRO test, I recommend the Commission conclude there are no non-quantifiable benefits associated with the PPA Rider.

#### 7 Q40. Can you summarize your conclusion on the ESP versus MRO test?

A40. Yes. As compared to an MRO, the proposed ESP III results in quantifiable costs between \$8 to \$32 million over the term of the ESP III and there are no non-quantifiable benefits.

#### V. TRANSMISSION COST RECOVERY RIDER

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# 12 Q41. How does AEP-Ohio presently recover transmission and ancillary services 13 costs from customers?

A41. For SSO customers, AEP-Ohio presently has a Transmission Cost Recovery Rider ("TCRR") that is designed to recover all transmission and transmission-related costs or credits, including ancillary and congestion costs, imposed on or charged to AEP-Ohio by FERC or PJM. The TCRR is fully avoidable by shopping customers. Shopping customers pay for transmission and ancillary services costs to PJM through their CRES provider, which obtains transmission and ancillary services on behalf of the customer through PJM. In some circumstances, shopping customers can be their own "load serving entity" and

procure transmission service directly from PJM. Transmission and ancillary services revenues collected by PJM from CRES providers serving customers in AEP-Ohio's service area are credited by PJM to AEP-Ohio's transmission business. This current structure provides AEP-Ohio with the opportunity to recover 100% of its transmission and ancillary services revenue requirement as authorized by FERC.

#### Q42. Has AEP-Ohio proposed any changes to its TCRR?

A42. Yes. AEP-Ohio is proposing to establish a non-bypassable Basic Transmission Cost Rider ("BTCR") to recover what AEP-Ohio classifies as non-market based transmission charges from all of its customers, both shopping and non-shopping. Other so-called market-based transmission charges would be included as part of the auction conducted to secure generation supply for SSO customers, and bidders in the auction would be expected to include their projected market-based transmission costs in their bids. CRES providers would continue to be responsible for market-based transmission charges associated with their shopping customers.

#### Q43. What does AEP-Ohio identify as non-market based transmission charges?

A43. The non-market based transmission charges that AEP-Ohio proposes be recovered through the BTCR are listed on Exhibit AEM-E attached to the testimony of Company witness Andrea Moore. The charges are associated with NITS, Transmission Enhancement, Reactive Supply and Voltage Control,

Transmission Owner Scheduling, System Control and Dispatch Service, and a credit for any Point to Point Transmission Service Revenues.

#### 3 Q44. Why did AEP-Ohio propose the BTCR?

A44. According to AEP-Ohio witness Pablo A. Vegas, the BTCR will ensure all customers, both shopping and non-shopping, only pay the actual cost of non-market based transmission expenses, and making this change will come at no cost to customers as the cost responsibilities are being shifted from CRES providers to AEP-Ohio. Mr. Vegas describes three reasons why AEP-Ohio has proposed the BTCR. First, the proposed changes will align AEP-Ohio's transmission recovery mechanism with other electric distribution utilities ("EDUs") in the state. Second, the change will enable CRES providers and SSO suppliers to operate and provide price rate offerings in a similar manner in different regions of the state. Third, Mr. Vegas testifies the change will result in shopping customers paying actual non-market based transmission costs, rather than estimated transmission costs.

# Q45. Are AEP-Ohio's proposed changes for the recovery of transmission-related costs appropriate?

A45. No. AEP-Ohio's proposed changes to the TCRR could disrupt the contractual relationship between AEP-Ohio customers that are presently shopping (who constitute the majority of AEP-Ohio's distribution sales) and their CRES providers. As previously noted, shopping customers presently pay for transmission and ancillary services available through PJM in the prices they pay

to CRES providers. Therefore, for customers on term contracts, the prices they
pay their CRES providers already include compensation for non-market based
transmission and ancillary services. If the Commission approves AEP-Ohio's
proposed BTCR, shopping customers with term contracts could end up
effectively paying twice for non-market based transmission and ancillary
services.

#### 7 Q46. Has AEP-Ohio acknowledged this risk to customers?

A46. Yes. In its response to IEU-Ohio Request for Admission 5-001, which is attached to my testimony as Exhibit KMM-11, AEP-Ohio has acknowledged that "[w]hether or not a customer will be billed twice for non-market based transmission costs will be dependent on the contract with their CRES provider." Thus, the claim that approval of the proposed BTCR will "come at no cost to customers" is simply inaccurate.

# Q47. Do you agree that approval of the proposed BTCR will align AEP-Ohio's recovery of transmission costs with other utilities in the state?

A47. Approval of the proposed BTCR will result in AEP-Ohio billing all customers, both shopping and non-shopping customers, for certain transmission and ancillary services costs. However, in response to IEU-Ohio Interrogatory 5-014, which is attached to my testimony as Exhibit KMM-12, AEP-Ohio has indicated there will continue to be differences in how each EDU bills and collects the costs associated with transmission and ancillary services from customers.

1	Q48.	Do you agree that approval of the BTCR is necessary to advance the
2		development of the competitive market?
3	A48.	No. The most recent report by the Commission Staff, which is attached to
4		testimony as Exhibit KMM-13, indicates that as of December 31, 2013, the
5		majority of retail sales volume in the AEP-Ohio territory, 61.13%, is from a CRES
6		provider. Thus, approval of the proposed BTCR is not necessary to advance the
7		development of the competitive market.
8	Q49.	Is the requirement that shopping customers pay actual non-market based
9		transmission costs rather than estimated transmission costs a benefit?
10	A49.	No. It is common practice for customers receiving service from a CRES provider
11		to structure their contracts to treat transmission and ancillary services costs as
12		either a cost reflected in a fixed price offer or a pass-through cost. Either
13		approach may be viewed as beneficial from a customer standpoint.
14		Under a fixed price approach (either a stated rate or a percentage discount to the
15		SSO rate), the CRES provider is assuming the transmission pricing risk and this
16		risk transfer can be valuable to the customer.
17		When transmission and ancillary services are treated as a pass through cost, it
18		provides customers with the ability to proactively manage their usage, and
19		reduce their energy usage and resulting electricity bill during times of peak
20		demand.

1	Q50.	Will t	the	BTCR	send	customers	more	transparent	and	apparent	price
2		signa	ls?								

A50.

No. PJM allocates NITS costs (which are the majority of costs to be collected through the proposed BTCR) through each customer peak load contribution to the single highest peak load in each transmission pricing zone. As I have previously stated, pricing options available through CRES providers allow for customers to contract for transmission service as a pass-through. This sends a very transparent pricing signal to each customer to reduce demand during peak load conditions and thereby reduce congestion that may otherwise result in higher prices or degradation in reliability.

In contrast, the proposed BTCR would allocate NITS costs among customer classes based upon the classes' coincident peak demand. However, the actual BTCR charges billed to customers with demand-based charges would be based upon monthly billing demand which is typically the customer's peak demand or based upon a demand ratchet. A customer's monthly peak demand or demand ratchet will have little, if any, relationship to the single zonal coincident peak within the PJM zone and thereby eliminate the demand response opportunity that is signaled to customers obtaining transmission service, directly or indirectly, through PJM. I would note that if non-quantifiable costs and benefits are to be considered for purposes of the ESP versus MRO test, the proposed BTCR should be regarded as a non-quantifiable cost with the understanding that it will detract from the ability of customers to effectively employ their demand response capabilities.

- 1 Q51. What are your recommendations regarding the proposed BTCR?
- 2 A51. The Commission should not adopt AEP-Ohio's proposed BTCR. The current
- 3 rider to recover transmission-related costs should remain in place and fully
- 4 avoidable by shopping customers.
- 5 VI. CONCLUSION
- 6 Q52. What are your overall recommendations on the proposed ESP III?
- 7 A52. If the Commission chooses to approve the ESP III, it should modify the proposal
- and direct AEP-Ohio to eliminate the PPA Rider and the POR program. The
- 9 Commission should also not approve the proposed BTCR and allow the current
- TCRR mechanism to remain in place.
- 11 Q53. Does this conclude your testimony?
- 12 A53. Yes.

### **CERTIFICATE OF SERVICE**

I hereby certify that a copy of the foregoing *Confidential Direct Testimony of Kevin M. Murray on Behalf of Industrial Energy Users-Ohio* will be served by AEP-Ohio pursuant to the terms of the protective agreement between IEU-Ohio and AEP-Ohio.

Frank P. Darr

Exhibit KMM-1

## **Exhibit KMM-1**

In the Matter of the Application of The Dayton Power and Light Company for Approval of Its Market Rate Offer, et al., Case Nos. 12-426-EL-SSO, et al.

In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company, PUCO Case No. 10-2929-EL-UNC.

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, PUCO Case Nos. 11-346-EL-SSO and 11-348-EL-SSO, et al.

In the Matter of the Application of Columbus Southern Power Company for Approval of its Electric Security Plan; an Amendment to its Corporate Separation Plan, and the Sale or Transfer of Certain Generating Assets, Case No. 08-917-EL-SSO and In the Matter of the Application of Ohio Power Company for Approval of its Electric Security Plan; and an Amendment to its Corporate Separation Plan, PUCO Case No. 08-918-EL-SSO (remand phase).

In the Matter of the Application of Columbus Southern Power for Approval of its Program Portfolio Plan and Request for Expedited Consideration, PUCO Case No. 09-1089-EL-POR.

In the Matter of the Application of Ohio Power Company for Approval of its Program Portfolio Plan and Request for Expedited Consideration, PUCO Case No. 09-1090-EL-POR.

In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Accounting Modifications Associated with Reconciliation Mechanism, and Tariffs for Generation Service, PUCO Case No. 09-906-EL-SSO.

In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Establish a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan, PUCO Case No. 08-935-EL-SSO.

In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Accounting Modifications Associated with Reconciliation Mechanism, and Tariffs for Generation Service, PUCO Case No. 08-936-EL-SSO.

In the Matter of the Application of Columbus Southern Power-Company for Approval of its Electric Security Plan; an Amendment to its Corporate Separation Plan; and the Sale or Transfer of Certain Generating Assets, PUCO Case No. 08-917-EL-SSO.

In the Matter of the Application of Ohio Power Company for Approval of its Electric Security Plan; and an Amendment to its Corporate Separation Plan, PUCO Case No. 08-918-EL-SSO.

In the Matter of the Application of Duke Energy Ohio for Approval of an Electric Security Plan, PUCO Case No. 08-920-EL-SSO.

In the Matter of the Application of The Dayton Power and Light Company for Approval of Its Electric Security Plan, PUCO Case No. 08-1094-EL-SSO.

Exhibit KMM-2

#### AMENDED AND RESTATED

# INTER-COMPANY POWER AGREEMENT

# DATED AS OF SEPTEMBER 10, 2010

## **AMONG**

OHIO VALLEY ELECTRIC CORPORATION,
ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.
APPALACHIAN POWER COMPANY,
BUCKEYE POWER GENERATING, LLC,
COLUMBUS SOUTHERN POWER COMPANY,
THE DAYTON POWER AND LIGHT COMPANY,
DUKE ENERGY OHIO, INC.,
FIRSTENERGY GENERATION CORP.,
INDIANA MICHIGAN POWER COMPANY,
KENTUCKY UTILITIES COMPANY,
LOUISVILLE GAS AND ELECTRIC COMPANY,
MONONGAHELA POWER COMPANY,
OHIO POWER COMPANY,
PENINSULA GENERATION COOPERATIVE, and
SOUTHERN INDIANA GAS AND ELECTRIC COMPANY

#### AMENDED AND RESTATED

# INTER-COMPANY POWER AGREEMENT

THIS AGREEMENT, dated as of September 10, 2010 (the "Agreement"), by and among Ohio Valley Electric Corporation (herein called OVEC), Allegheny Energy SUPPLY COMPANY, L.L.C. (herein called Allegheny), APPALACHIAN POWER COMPANY (herein called Appalachian), BUCKEYE POWER GENERATING, LLC (herein called Buckeye), COLUMBUS SOUTHERN POWER COMPANY (herein called Columbus), THE DAYTON POWER AND LIGHT COMPANY (herein called Dayton), DUKE ENERGY OHIO, INC. (formerly known as The Cincinnati Gas & Electric Company and herein called Duke Ohio), FIRSTENERGY GENERATION CORP. (herein called FirstEnergy), INDIANA MICHIGAN POWER COMPANY (herein called Indiana), KENTUCKY UTILITIES COMPANY (herein called Kentucky), LOUISVILLE GAS AND ELECTRIC COMPANY (herein called Louisville), MONONGAHELA POWER COMPANY (herein called Monongahela), Ohio Power Company (herein called Ohio Power), Peninsula Generation COOPERATIVE (herein called Peninsula), and SOUTHERN INDIANA GAS AND ELECTRIC COMPANY (herein called Southern Indiana, and all of the foregoing, other than OVEC, being herein sometimes collectively referred to as the Sponsoring Companies and individually as a Sponsoring Company) hereby amends and restates in its entirety, the Inter-Company Power Agreement dated as of March 13, 2006, as amended by Modification No. 1, dated as of March 13, 2006 (herein called the Current Agreement), by and among OVEC and the Sponsoring Companies.

#### WITNESSETH THAT:

Whereas, the Current Agreement amended and restated the original Inter-Company Power Agreement, dated as of July 10, 1953, as amended by Modification No. 1, dated as of June 3, 1966; Modification No. 2, dated as of January 7, 1967; Modification No. 3, dated as of November 15, 1967; Modification No. 4, dated as of November 5, 1975; Modification No. 5, dated as of September 1, 1979; Modification No. 6, dated as of August 1, 1981; Modification No. 7, dated as of January 15, 1992; Modification No. 8, dated as of January 19, 1994; Modification No. 9, dated as of August 17, 1995; Modification No. 10, dated as of January 1, 1998; Modification No. 11, dated as of April 1, 1999; Modification No. 12, dated as of November 1, 1999; Modification No. 13, dated as of May 24, 2000; Modification No. 14, dated as of April 1, 2001; and Modification No. 15, dated as of April 30, 2004 (together, herein called the Original Agreement); and

W HEREAS, OVEC designed, purchased, and constructed, and continues to operate and maintain two steam-electric generating stations, one station (herein called Ohio Station) consisting of five turbo-generators and all other necessary equipment, at a location on the Ohio River near Cheshire, Ohio, and the other station (herein called Indiana Station) consisting of six turbogenerators and all other necessary equipment, at a location on the Ohio River near Madison,

Indiana, (the Ohio Station and the Indiana Station being herein called the Project Generating Stations); and

WHEREAS, OVEC also designed, purchased, and constructed, and continues to operate and maintain necessary transmission and general plant facilities (herein called the Project Transmission Facilities) and OVEC established or cause to be established interconnections between the Project Generating Stations and the systems of certain of the Sponsoring Companies; and

WHEREAS, OVEC entered into an agreement, attached hereto as Exhibit A, with Indiana-Kentucky Electric Corporation (herein called IKEC), a corporation organized under the laws of the State of Indiana as a wholly owned subsidiary corporation of OVEC, which has been amended and restated as of the date of this Agreement and embodies the terms and conditions for the ownership and operation by IKEC of the Indiana Station and such portion of the Project Transmission Facilities which are to be owned and operated by it; and

WHEREAS, transmission facilities were constructed by certain of the Sponsoring Companies to interconnect the systems of such Sponsoring Companies, directly or indirectly, with the Project Generating Stations and/or the Project Transmission Facilities, and the Sponsoring Companies have agreed to pay for Available Power, as hereinafter defined, as may be available at the Project Generating Stations; and

WHEREAS, the parties hereto desire to amend and restate in their entirety, the Current Agreement to define the terms and conditions governing the rights of the Sponsoring Companies to receive Available Power from the Project Generating Stations and the obligations of the Sponsoring Companies to pay therefor.

Now, THEREFORE, the parties hereto agree with each other as follows:

# ARTICLE 1

# **DEFINITIONS**

- 1.01. For the purposes of this Agreement, the following terms, wherever used herein, shall have the following meanings:
  - 1.011 "Affiliate" means, with respect to a specified person, any other person that directly or indirectly through one or more intermediaries controls, is controlled by, or is under common control with, such specified person; provided that "control" for these purposes means the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of a person, whether through the ownership of voting securities, by contract or otherwise.

- 1.012 "Arbitration Board" has the meaning set forth in Section 9.10.
- 1.013 "Available Energy" of the Project Generating Stations means the energy associated with Available Power.
- 1.014 "Available Power" of the Project Generating Stations at any particular time means the total net kilowatts at the 345-kV busses of the Project Generating Stations which Corporation in its sole discretion will determine that the Project Generating Stations will be capable of safely delivering under conditions then prevailing, including all conditions affecting capability.
- 1.015 "Corporation" means OVEC, IKEC, and all other subsidiary corporations of OVEC.
- 1.016 "Decommissioning and Demolition Obligation" has the meaning set forth in Section 5.03(f) hereof.
- 1.017 "Effective Date" means September 10, 2010, or to the extent necessary, such later date on which Corporation notifies the Sponsoring Companies that all conditions to effectiveness, including all required waiting periods and all required regulatory acceptances or approvals, of this Agreement have been satisfied in form and substance satisfactory to the Corporation.
- 1.018 "Election Period" has the meaning set forth in Section 9.183(a) hereof.
- 1.019 "Minimum Generating Unit Output" means 80 MW (net) for each of the Corporation's generation units; provided that such "Minimum Generating Unit Output" shall be confirmed from time to time by operating tests on the Corporation's generation units and shall be adjusted by the Operating Committee as appropriate following such tests.
- 1.0110 "Minimum Loading Event" means a period of time during which one or more of the Corporation's generation units are operating at below the Minimum Generating Output as a result of the Sponsoring Companies' failure to schedule and take delivery of sufficient Available Energy.
- 1.0111 "Minimum Loading Event Costs" means the sum of the following costs caused by one or more Minimum Loading Events: (i) the actual costs of any of the Corporation's generating units burning fuel oil; and (ii) the estimated actual additional costs to the Corporation resulting from Minimum Loading Events, including without limitation the incremental costs of additional emissions allowances, reflected in the schedule of charges prepared by the Operating Committee and in effect as of the commencement of any Minimum Loading Event, which schedule may be adjusted from time to time as necessary by the Operating Committee.

1.0112 "Month" means a calendar month.

1.0113 "Nominal Power Available" means an individual Sponsoring Company's Power Participation Ratio share of the Corporation's current estimate of the maximum amount of Available Power available for delivery at any given time.

1.0114 "Offer Notice" means the notice required to be given to the other Sponsoring Companies by a Transferring Sponsor offering to sell all or a portion of such Transferring Sponsor's rights, title and interests in, and obligations under this Agreement. At a minimum, the Offer Notice shall be in writing and shall contain (i) the rights, title and interests in, and obligations under this Agreement that the Transferring Sponsor proposes to Transfer; and (ii) the cash purchase price and any other material terms and conditions of such proposed transfer. An Offer Notice may not contain terms or conditions requiring the purchase of any non-OVEC interests.

1.0115 "Permitted Assignee" means a person that is (a) a Sponsoring Company or its Affiliate whose long-term unsecured non-credit enhanced indebtedness. as of the date of such assignment, has a Standard & Poor's credit rating of at least BBBand a Moody's Investors Service, Inc. credit rating of at least Baa3 (provided that, if the proposed assignee's long-term unsecured non-credit enhanced indebtedness is not currently rated by one of Standard & Poor's or Moody, such assignee's long-term unsecured non-credit enhanced indebtedness, as of the date of such assignment, must have either a Standard & Poor's credit rating of at least BBB- or a Moody's Investors Service, Inc. credit rating of at least Baa3); or (b) a Sponsoring Company or its Affiliate that does not meet the criteria in subsection (a) above, if the Sponsoring Company or its Affiliate that is assigning its rights, title and interests in, and obligations under, this Agreement agrees in writing (in form and substance satisfactory to Corporation) to remain obligated to satisfy all of the obligations related to the assigned rights, title and interests to the extent such obligations are not satisfied by the assignee of such rights, title and interests; provided that, in no event shall a person be deemed a "Permitted Assignee" if counsel for the Corporation reasonably determines that the assignment of the rights, title or interests in, or obligations under, this Agreement to such person could cause a termination, default, loss or payment obligation under any security issued, or agreement entered into, by the Corporation prior to such transfer.

1.0116 "Postretirement Benefit Obligation" has the meaning set forth in Section 5.03(e) hereof.

1.0117 "Power Participation Ratio" as applied to each of the Sponsoring Companies refers to the percentage set forth opposite its respective name in the tabulation below:

Company

Power Participation Ratio—Percent

Allegheny	3.01
Appalachian	15.69
Buckeye	18.00
Columbus	4,44
Dayton	4.90
Duke Ohio	9.00
FirstEnergy	4.85
Indiana	7.85
Kentucky	2.50
Louisville	5.63
Monongahela	0.49
Ohio Power	15.49
Peninsula	6.65
Southern Indiana	1.50
Total	100.0

1.0118 "Tariff" means the open access transmission tariff of the Corporation, as amended from time to time, or any successor tariff, as accepted by the Federal Energy Regulatory Commission or any successor agency.

1.0119 "Third Party" means any person other than a Sponsoring Company or its Affiliate.

1.0120 "Total Minimum Generating Output" means the product of the Minimum Generating Unit Output times the number of the Corporation's generation units available for service at that time.

1.0121 "Transferring Sponsor" has the meaning set forth in Section 9.183(a) hereof.

1.0122 "Uniform System of Accounts" means the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission as in effect on January 1, 2004.

# ARTICLE 2

#### TRANSMISSION AGREEMENT AND FACILITIES

2.01. Transmission Agreement. The Corporation shall enter into a transmission service agreement under the Tariff, and the Corporation shall reserve and schedule transmission service, ancillary services and other transmission-related services in accordance with the Tariff to provide for the delivery of Available Power and Available Energy to the applicable delivery point under this Agreement.

2.02. Limited Burdening of Corporation's Transmission Facilities.

Transmission facilities owned by the Corporation, including the Project Transmission Facilities, shall not be burdened by power and energy flows of any Sponsoring Company to an extent which would impair or prevent the transmission of Available Power.

#### **ARTICLE 3**

[RESERVED]

### ARTICLE 4

#### AVAILABLE POWER SUPPLY

- 4.01. Operation of Project Generating Stations. Corporation shall operate and maintain the Project Generating Stations in a manner consistent with safe, prudent, and efficient operating practice so that the Available Power available from said stations shall be at the highest practicable level attainable consistent with OVEC's obligations under Reliability First Reliability Standard BAL-002-RFC throughout the term of this Agreement.
- 4.02. Available Power Entitlement. The Sponsoring Companies collectively shall be entitled to take from Corporation and Corporation shall be obligated to supply to the Sponsoring Companies any and all Available Power and Available Energy pursuant to the provisions of this Agreement. Each Sponsoring Company's Available Power Entitlement hereunder shall be its Power Participation Ratio, as defined in *subsection* 1.0117, of Available Power.
- 4.03. Available Energy. Corporation shall make Available Energy available to each Sponsoring Company in proportion to said Sponsoring Company's Power Participation Ratio. No Sponsoring Company, however, shall be obligated to avail itself of any Available Energy. Available Energy shall be scheduled and taken by the Sponsoring Companies in accordance with the following procedures:
  - 4.031 Each Sponsoring Company shall schedule the delivery of all or any portion (in whole MW increments) of its entitlement to Available Energy in accordance with scheduling procedures established by the Operating Committee from time to time.
  - 4.032 In the event that any Sponsoring Company does not schedule the delivery of all of its Power Participation Ratio share of Available Energy, then each such other Sponsoring Company may schedule the delivery of all or any portion (in whole MW increments) of any such unscheduled share of Available Energy (through successive allotments if necessary) in proportion to their Power Participation Ratios.

4.033 Notwithstanding any Available Energy schedules made in accordance with this Section 4.03 and the applicable scheduling procedures, (i) the Corporation shall adjust all schedules to the extent that the Corporation's actual generation output is less than or more than the expected Nominal Power Available to all Sponsoring Companies, or to the extent that the Corporation is unable to obtain sufficient transmission service under the Tariff for the delivery of all scheduled Available Energy; and (ii) immediately following a Minimum Loading Event, any Sponsoring Company causing (in whole or part) such Minimum Loading Event shall have its Available Energy schedules increased after the schedules of the Sponsoring Companies not causing such Minimum Load Event, in accordance with the estimated ramp rates associated with the shutdown and start-up of the Corporation's generation units as reflected in the schedules prepared by the Operating Committee and in effect as of the commencement of any Minimum Loading Event, which schedules may be adjusted from time to time as necessary by the Operating Committee.

4.034 Each Sponsoring Company availing itself of Available Energy shall be entitled to an amount of energy (herein called billing kilowatt-hours of Available Energy) equal to its portion, determined as provided in this Section 4.03, of the total Available Energy after deducting therefrom such Sponsoring Company's proportionate share, as defined in this Section 4.03, of all losses as determined in accordance with the Tariff incurred in transmitting the total of such Available Energy from the 345-kV busses of the Project Generating Stations to the applicable delivery points, as scheduled pursuant to Section 9.01, of all Sponsoring Companies availing themselves of Available Energy. The proportionate share of all such losses that shall be so deducted from such Sponsoring Company's portion of Available Energy shall be equal to all such losses multiplied by the ratio of such portion of Available Energy to the total of such Available Energy. Each Sponsoring Company shall have the right, pursuant to this Section 4.03, to avail itself of Available Energy for the purpose of meeting the loads of its own system and/or of supplying energy to other systems in accordance with agreements, other than this Agreement, to which such Sponsoring Company is a party.

4.035 To the extent that, as a result of the failure by one or more Sponsoring Companies to take its respective Power Participation Ratio share of the applicable Total Minimum Generating Output during any hour, a Minimum Loading Event shall occur, then such one or more Sponsoring Companies shall be assessed charges for any Minimum Loading Event Costs in accordance with Section 5.05.

#### ARTICLE 5

CHARGES FOR AVAILABLE POWER AND MINIMUM LOADING EVENT COSTS

5.01. Total Monthly Charge. The amount to be paid to Corporation each month by the Sponsoring Companies for Available Power and Available Energy supplied under this

Agreement shall consist of the sum of an energy charge, a demand charge, and a transmission charge, all determined as set forth in this *Article* 5.

- 5.02. Energy Charge. The energy charge to be paid each month by the Sponsoring Companies for Available Energy shall be determined by Corporation as follows:
  - 5.021 Determine the aggregate of all expenses for fuel incurred in the operation of the Project Generating Stations, in accordance with Account 501 (Fuel), Account 506.5 (Variable Reagent Costs Associated With Pollution Control Facilities) and 509 (Allowances) of the Uniform System of Accounts.
  - 5.022 Determine for such month the difference between the total cost of fuel as described in subsection 5.021 above and the total cost of fuel included in any Minimum Loading Event Costs payable to the Corporation for such month pursuant to Section 8.03. For the purposes hereof the difference so determined shall be the fuel cost allocable for such month to the total kilowatt-hours of energy generated at the Project Generating Stations for the supply of Available Energy. For Available Energy availed of by the Sponsoring Companies, each Sponsoring Company shall pay Corporation for each such month an amount obtained by multiplying the ratio of the billing kilowatt-hours of such Available Energy availed of by such Sponsoring Company during such month to the aggregate of the billing kilowatt-hours of all Available Energy availed of by all Sponsoring Companies during such month times the total cost of fuel as described in this subsection 5.022 for such month.
- 5.03. Demand Charge. During the period commencing with the Effective Date and for the remainder of the term of this Agreement, demand charges payable by the Sponsoring Companies to Corporation shall be determined by the Corporation as provided below in this Section 5.03. Each Sponsoring Company's share of the aggregate demand charges shall be the percentage of such charges represented by its Power Participation Ratio.

The aggregate demand charge payable each month by the Sponsoring Companies to Corporation shall be equal to the total costs incurred for such month by Corporation resulting from its ownership, operation, and maintenance of the Project Generating Stations and Project Transmission Facilities determined as follows:

As soon as practicable after the close of each calendar month the following components of costs of Corporation (eliminating any duplication of costs which might otherwise be reflected among the corporate entities comprising Corporation) applicable for such month to the ownership, operation and maintenance of the Project Generating Stations and the Project Transmission Facilities, including additional facilities and/or spare parts (such as fuel processing plants, flue gas or waste product processing facilities, and facilities reasonably required to enable the Corporation to limit the emission of pollutants or the discharge of wastes in compliance with governmental requirements) and

replacements necessary or desirable to keep the Project Generating Stations and the Project Transmission Facilities in a dependable and efficient operating condition, and any provision for any taxes that may be applicable to such charges, to be determined and recorded in the following manner:

- Component (A) shall consist of fixed charges made up of (i) the amounts of interest properly chargeable to Accounts 427, 430 and 431, less the amount thereof credited to Account 432, of the Uniform System of Accounts, including the interest component of any purchase price, interest, rental or other payment under an installment sale, loan, lease or similar agreement relating to the purchase, lease or acquisition by Corporation of additional facilities and replacements (whether or not such interest or other amounts have come due or are actually payable during such Month), (ii) the amounts of amortization of debt discount or premium and expenses properly chargeable to Accounts 428 and 429, and (iii) an amount equal to the sum of (I) the applicable amount of the debt amortization component for such month required to retire the total amount of indebtedness of Corporation issued and outstanding, (II) the amortization requirement for such month in respect of indebtedness of Corporation incurred in respect of additional facilities and replacements, and (III) to the extent not provided for pursuant to clause (II) of this clause (iii), an appropriate allowance for depreciation of additional facilities and replacements.
- **(b)** Component (B) shall consist of the total operating expenses for labor, maintenance, materials, supplies, services, insurance, administrative and general expense, etc., properly chargeable to the Operation and Maintenance Expense Accounts of the Uniform System of Accounts (exclusive of Accounts 501, 509, 555, 911, 912, 913, 916, and 917 of the Uniform System of Accounts), minus the total of all non-fuel costs included in any Minimum Loading Event Costs payable to the Corporation for such month pursuant to Section 8.03, minus the total of all transmission charges payable to the Corporation for such month pursuant to Section 5.04, and plus any additional amounts which, after provision for all income taxes on such amounts (which shall be included in Component (C) below), shall equal any amounts paid or payable by Corporation as fines or penalties with respect to occasions where it is asserted that Corporation failed to comply with a law or regulation relating to the emission of pollutants or the discharge of wastes.
- (c) Component (C) shall consist of the total expenses for taxes, including all taxes on income but excluding any federal income taxes arising from payments to Corporation under Component (D) below, and all operating or other costs or expenses, net of income, not included or

specifically excluded in Components (A) or (B) above, including tax adjustments, regulatory adjustments, net losses for the disposition of property and other net costs or expenses associated with the operation of a utility.

- (d) Component (D) shall consist of an amount equal to the product of \$2.089 multiplied by the total number of shares of capital stock of the par value of \$100 per share of Ohio Valley Electric Corporation which shall have been issued and which are outstanding on the last day of such month.
- (e) Component (E) shall consist of an amount to be sufficient to pay the costs and other expenses relating to the establishment, maintenance and administration of life insurance, medical insurance and other postretirement benefits other than pensions attributable to the employment and employee service of active employees, retirees, or other employees, including without limitation any premiums due or expected to become due, as well as administrative fees and costs, such amounts being sufficient to provide payment with respect to all periods for which Corporation has committed or is otherwise obligated to make such payments, including amounts attributable to current employee service and any unamortized prior service cost, gain or loss attributable to prior service years ("Postretirement Benefit Obligation"); provided that, the amount payable for Postretirement Benefit Obligations during any month shall be determined by the Corporation based on, among other factors, the Statement of Financial Accounting Standards No. 106 (Employers' Accounting For Postretirement Benefits Other Than Pensions) and any applicable accounting standards, policies or practices as adopted from time to time relating to accruals with respect to all or any portion of such Postretirement Benefit Obligation.
- (f) Component (F) shall consist of an amount that may be incurred in connection with the decommissioning, shutdown, demolition and closing of the Project Generating Stations when production of electric power and energy is discontinued at such Project Generating Stations, which amount shall include, without limitation the following costs (net of any salvage credits): the costs of demolishing the plants' building structures, disposal of non-salvageable materials, removal and disposal of insulating materials, removal and disposal of storage tanks and associated piping, disposal or removal of materials and supplies (including fuel oil and coal), grading, covering and reclaiming storage and disposal areas, disposing of ash in ash ponds to the extent required by regulatory authorities, undertaking corrective or remedial action required by regulatory authorities, and any other costs incurred in putting the facilities

in a condition necessary to protect health or the environment or which are required by regulatory authorities, or which are incurred to fund continuing obligations to monitor or to correct environmental problems which result, or are later discovered to result, from the facilities' operation, closure or post-closure activities ("Decommissioning and Demolition Obligation") provided that, the amount payable for Decommissioning and Demolition Obligations during any month shall be calculated by Corporation based on, among other factors, the thenestimated useful life of the Project Generating Stations and any applicable accounting standards, policies or practices as adopted from time to time relating to accruals with respect to all or any portion of such Decommissioning and Demolition Obligation, and provided further that, the Corporation shall recalculate the amount payable under this Component (F) for future months from time to time, but in no event later than five (5) years after the most recent calculation.

- 5.04. Transmission Charge. The transmission charges to be paid each month by the Sponsoring Companies shall be equal to the total costs incurred for such month by Corporation for the purchase of transmission service, ancillary services and other transmission-related services under the Tariff as reserved and scheduled by the Corporation to provide for the delivery of Available Power and Available Energy to the applicable delivery point under this Agreement. Each Sponsoring Company's share of the aggregate transmission charges shall be the percentage of such charges represented by its Power Participation Ratio.
- 5.05. Minimum Loading Event Costs. To the extent that, as a result of the failure by one or more Sponsoring Companies to take its respective Power Participation Ratio share of the applicable Total Minimum Generating Output during any hour, a Minimum Loading Event shall occur, then the sum of all Minimum Loading Event Costs relating to such Minimum Loading Event shall be charged to such Sponsoring Company or group of Sponsoring Companies that failed take its respective Power Participation Ratio share of the applicable Total Minimum Generating Output during such period, with such Minimum Loading Event Costs allocated among such Sponsoring Companies on a pro-rata basis in accordance with such Sponsoring Company's MWh share of the MWh reduction in the delivery of Available Energy causing any Minimum Loading Event. The applicable charges for Minimum Loading Event Costs as determined by the corporation in accordance with Section 5.05 shall be paid each month by the applicable Sponsoring Companies.

#### ARTICLE 6

# Metering of Energy Supplied

6.01. Measuring Instruments. The parties hereto shall own and maintain such metering equipment as may be necessary to provide complete information regarding the delivery of power and energy to or for the account of any of the parties hereto; and the ownership and

expense of such metering shall be in accordance with agreements among them. Each party will at its own expense make such periodic tests and inspections of its meters as may be necessary to maintain them at the highest practical commercial standard of accuracy and will advise all other interested parties hereto promptly of the results of any such test showing an inaccuracy of more than 1%. Each party will make additional tests of its meters at the request of any other interested party. Other interested parties shall be given notice of, and may have representatives present at, any test and inspection made by another party.

#### **ARTICLE 7**

COSTS OF REPLACEMENTS AND ADDITIONAL FACILITIES;
PAYMENTS FOR EMPLOYEE BENEFITS;
DECOMMISSIONING, SHUTDOWN, DEMOLITION AND CLOSING CHARGES

- 7.01. Replacement Costs. The Sponsoring Companies shall reimburse Corporation for the difference between (a) the total cost of replacements chargeable to property and plant made by Corporation during any month prior thereto (and not previously reimbursed) and (b) the amounts received by Corporation as proceeds of fire or other applicable insurance protection, or amounts recovered from third parties responsible for damages requiring replacement, plus provision for all taxes on income on such difference; provided that, to the extent that the Corporation arranges for the financing of any replacements, the payments due under this Section 7.01 shall equal the amount of all principal, interest, taxes and other costs and expenses related to such financing during any month. Each Sponsoring Company's share of such payment shall be the percentage of such costs represented by its Power Participation Ratio. The term cost of replacements, as used herein, shall include all components of cost, plus removal expense, less salvage.
- 7.02. Additional Facility Costs. The Sponsoring Companies shall reimburse Corporation for the total cost of additional facilities and/or spare parts purchased and/or installed by Corporation during any month prior thereto (and not previously reimbursed), plus provision for all taxes on income on such costs; provided that, to the extent that the Corporation arranges for the financing of any additional facilities and/or spare parts, the payments due under this Section 7.02 shall equal the amount of all principal, interest, taxes and other costs and expenses related to such financing during any month. Each Sponsoring Company's share of such payment shall be the percentage of such costs represented by its Power Participation Ratio.
- 7.03. Payments for Employee Benefits. Not later than the effective date of termination of this Agreement, each Sponsoring Company will pay to Corporation its Power Participation Ratio share of additional amounts, after provision for any taxes that may be applicable thereto, sufficient to cover any shortfall if the amount of the Postretirement Benefit Obligation collected by the Corporation prior to the effective date of termination of the Agreement is insufficient to permit Corporation to fulfill its commitments or obligations with respect to both postemployment benefit obligations under the Statement of Financial Accounting Standards No. 112 and postretirement benefits other than pensions, as determined by Corporation

with the aid of an actuary or actuaries selected by the Corporation based on the terms of the Corporation's then-applicable plans.

7.04. Decommissioning, Shutdown, Demolition and Closing. The Sponsoring Companies recognize that a part of the cost of supplying power to it under this Agreement is the amount that may be incurred in connection with the decommissioning, shutdown, demolition and closing of the Project Generating Stations when production of electric power and energy is discontinued at such Project Generating Stations. Not later than the effective date of termination of this Agreement, each Sponsoring Company will pay to Corporation its Power Participation Ratio share of additional amounts, after provision for any taxes that may be applicable thereto, sufficient to cover any shortfall if the amount of the Decommissioning and Demolition Obligation collected by the Corporation prior to the effective date of termination of the Agreement is insufficient to permit Corporation to complete the decommissioning, shutdown, demolition and closing of the Project Generating Stations, based on the Corporation's recalculation of the Decommissioning and Demolition Obligation in accordance with Section 5.03(f) of this Agreement no earlier than twelve (12) months before the effective date of termination of this Agreement.

## **ARTICLE 8**

## BILLING AND PAYMENT

- 8.01. Available Power, and Replacement and Additional Facility Costs. As soon as practicable after the end of each month Corporation shall render to each Sponsoring Company a statement of all Available Power and Available Energy supplied to or for the account of such Sponsoring Company during such month, specifying the amount due to the Corporation therefor, including any amounts for reimbursement for the cost of replacements and additional facilities and/or spare parts incurred during such month, pursuant to Articles 5 and 7 above. Such Sponsoring Company shall make payment therefor promptly upon the receipt of such statement, but in no event later than fifteen (15) days after the date of receipt of such statement. In case any factor entering into the computation of the amount due for Available Power and Available Energy cannot be determined at the time, it shall be estimated subject to adjustment when the actual determination can be made.
- 8.02. Provisional Payments for Available Power. The Sponsoring Companies shall, from time to time, at the request of the Corporation, make provisional semi-monthly payments for Available Power in amounts approximately equal to the estimated amounts payable for Available Power delivered by Corporation to the Sponsoring Companies during each semi-monthly period. As soon as practicable after the end of each semi-monthly period with respect to which Corporation has requested the Sponsoring Companies to make provisional semi-monthly payments for Available Power, Corporation shall render to each Sponsoring Company a separate statement indicating the amount payable by such Sponsoring Company for such semi-monthly period. Such Sponsoring Company shall make payment therefor promptly upon receipt of such statement, but in no event later than fifteen (15) days after the date of receipt of such

statement and the amounts so paid by such Sponsoring Company shall be credited to the account of such Sponsoring Company with respect to future payments to be made pursuant to *Articles* 5 and 7 above by such Sponsoring Company to Corporation for Available Power.

- 8.03. Minimum Loading Event Costs. As soon as practicable after the end of each month, Corporation shall render to each Sponsoring Company a statement indicating any applicable charges for Minimum Loading Event Costs pursuant to Section 5.05 during such month, specifying the amount due to the Corporation therefor pursuant to Article 5 above. Such Sponsoring Company shall make payment therefor promptly upon the receipt of such statement, but in no event later than fifteen (15) days after the date of receipt of such statement. In case the computation of the amount due for Minimum Loading Event Costs cannot be determined at the time, it shall be estimated subject to adjustment when the actual determination can be made, and all payments shall be subject to subsequent adjustment.
- 8.04. Unconditional Obligation to Pay Demand and Other Charges. The obligation of each Sponsoring Company to pay its specified portion of the Demand Charge under Section 5.03, the Transmission Charge under Section 5.04, and all charges under Article 7 for any Month shall not be reduced irrespective of:
  - (a) whether or not any Available Power or Available Energy are supplied by the Corporation during such calendar month and whether or not any Available Power or Available Energy are accepted by any Sponsoring Company during such calendar month;
  - (b) the existence of any claim, set-off, defense, reduction, abatement or other right (other than irrevocable payment, performance, satisfaction or discharge in full) that such Sponsoring Company may have, or which may at any time be available to or be asserted by such Sponsoring Company, against the Corporation, any other Sponsoring Company, any creditor of the Corporation or any other Person (including, without limitation, arising as a result of any breach or alleged breach by either the Corporation, any other Sponsoring Company, any creditor of the Corporation or any other Person under this Agreement or any other agreement (whether or not related to the transactions contemplated by this Agreement or any other agreement) to which such party is a party); or
  - (c) the validity or enforceability against any other Sponsoring Company of this Agreement or any right or obligation hereunder (or any release or discharge thereof) at any time.

## **ARTICLE 9**

## GENERAL PROVISIONS

9.01. Characteristics of Supply and Points of Delivery. All power and energy delivered hereunder shall be 3-phase, 60-cycle, alternating current, at a nominal unregulated voltage designated for the point of delivery as described in this Article 9. Available Power and Available Energy to be delivered between Corporation and the Sponsoring Companies pursuant to this Agreement shall be delivered under the terms and conditions of the Tariff at the points, as scheduled by the Sponsoring Company in accordance with procedures established by the Operating Committee and in accordance with Section 9.02, where the transmission facilities of Corporation interconnect with the transmission facilities of any Sponsoring Company (or its successor or predecessor); provided that, to the extent that a joint and common market is established for the sale of power and energy by Sponsoring Companies within one or more of the regional transmission organizations or independent system operators approved by the Federal Energy Regulatory Commission in which the Sponsoring Companies are members or otherwise participate, then Corporation and the Sponsoring Companies shall take such action as reasonably necessary to permit the Sponsoring Companies to bid their entitlement to power and energy from Corporation into such market(s) in accordance with the procedures established for such market(s).

Modification of Delivery Schedules Based on Available Transmission 9.02. Capability. To the extent that transmission capability available for the delivery of Available Power and Available Energy at any delivery point is less than the total amount of Available Power and Available Energy scheduled for delivery by the Sponsoring Companies at such delivery point in accordance with Section 9.01, then the following procedures shall apply and the Corporation and the applicable Sponsoring Companies shall modify their delivery schedules accordingly until the total amount of Available Power and Available Energy scheduled for delivery at such delivery point is equal to or less than the transmission capability available for the delivery of Available Power and Available Energy: (a) the transmission capability available for the delivery of Available Power and Available Energy at the following delivery points shall be allocated first on a pro rata basis (in whole MW increments) to the following Sponsoring Companies up to their Power Participation Ratio share of the total amount of Available Energy available to all Sponsoring Companies (and as applicable, further allocated among Sponsoring Companies entitled to allocation under this Section 9.02(a) in accordance with their Power Participation Ratios): (i) to Allegheny, Appalachian, Buckeye, Columbus, FirstEnergy, Indiana, Monongahela, Ohio Power and Peninsula (or their successors) for deliveries at the points of interconnection between the Corporation and Appalachian, Columbus, Indiana or Ohio Power, or their successors; (ii) to Duke Ohio (or its successor) for deliveries at the points of interconnection between the Corporation and Duke Ohio or its successor; (iii) to Dayton (or its successor) for deliveries at the points of interconnection between the Corporation and Dayton or its successor; and (iv) to Kentucky, Louisville and Southern Indiana (or their successors) for deliveries at the points of interconnection between the Corporation and Louisville or Kentucky, or their successors; and (b) any remaining transmission capability available for the delivery of

Available Power and Available Energy shall be allocated on a pro rata basis (in whole MW increments) to the Sponsoring Companies in accordance with their Power Participation Ratios.

9.03. Operation and Maintenance of Systems Involved. Corporation and the Sponsoring Companies shall operate their systems in parallel, directly or indirectly, except during emergencies that temporarily preclude parallel operation. The parties hereto agree to coordinate their operations to assure maximum continuity of service from the Project Generating Stations, and with relation thereto shall cooperate with one another in the establishment of schedules for maintenance and operation of equipment and shall cooperate in the coordination of relay protection, frequency control, and communication and telemetering systems. The parties shall build, maintain and operate their respective systems in such a manner as to minimize so far as practicable rapid fluctuations in energy flow among the systems. The parties shall cooperate with one another in the operation of reactive capacity so as to assure mutually satisfactory power factor conditions among themselves.

The parties hereto shall exercise due diligence and foresight in carrying out all matters related to the providing and operating of their respective power resources so as to minimize to the extent practicable deviations between actual and scheduled deliveries of power and energy among their systems. The parties hereto shall provide and/or install on their respective systems such communication, telemetering, frequency and/or tie-line control facilities essential to so minimizing such deviations; and shall fully cooperate with one another and with third parties (such third parties whose systems are either directly or indirectly interconnected with the systems of the Sponsoring Companies and who of necessity together with the parties hereto must unify their efforts cooperatively to achieve effective and efficient interconnected systems operation) in developing and executing operating procedures that will enable the parties hereto to avoid to the extent practicable deviations from scheduled deliveries.

In order to foster coordination of the operation and maintenance of Corporation's transmission facilities with those facilities of Sponsoring Companies that are owned or functionally controlled by a regional transmission organization or independent system operator, Corporation shall use commercially reasonable efforts to enter into a coordination agreement with any regional transmission organization or independent system operator approved by the Federal Energy Regulatory Commission that operates transmission facilities that interconnect with Corporation's transmission facilities, and to enter into a mutually agreeable services agreement with a regional transmission organization or independent system operator to provide the Corporation with reliability and security coordination services and other related services.

9.04. Power Deliveries as Affected by Physical Characteristics of Systems. It is recognized that the physical and electrical characteristics of the transmission facilities of the interconnected network of which the transmission systems of the Sponsoring Companies, Corporation, and other systems of third parties not parties hereto are a part, may at times preclude the direct delivery at the points of interconnection between the transmission systems of one or more of the Sponsoring Companies and Corporation, of some portion of the energy supplied under this Agreement, and that in each such case, because of said characteristics, some

of the energy will be delivered at points which interconnect the system of one or more of the Sponsoring Companies with systems of companies not parties to this Agreement. The parties hereto shall cooperate in the development of mutually satisfactory arrangements among themselves and with such companies not parties hereto whereby the supply of power and energy contemplated hereunder can be fulfilled.

9.05. Operating Committee. There shall be an "Operating Committee" consisting of one member appointed by the Corporation and one member appointed by each of the Sponsoring Companies electing so to do; provided that, if any two or more Sponsoring Companies are Affiliates, then such Affiliates shall together be entitled to appoint only one member to the Operating Committee. The "Operating Committee" shall establish (and modify as necessary) scheduling, operating, testing and maintenance procedures of the Corporation in support of this Agreement, including establishing: (i) procedures for scheduling delivery of Available Energy under Section 4.03, (ii) procedures for power and energy accounting, (iii) procedures for the reservation and scheduling of firm and non-firm transmission service under the Tariff for the delivery of Available Power and Available Energy, (iv) the Minimum Generating Unit Output, and (v) the form of notifications relating to power and energy and the price thereof. In addition, the Operating Committee shall consider and make recommendations to Corporation's Board of Directors with respect to such other problems as may arise affecting the transactions under this Agreement. The decisions of the Operating Committee, including the adoption or modification of any procedure by the Operating Committee pursuant to this Section 9.04, must receive the affirmative vote of at least two-thirds of the members of the Operating Committee, regardless of the number of members of the Operating Committee present at any meeting.

9.06. Acknowledgment of Certain Rights. For the avoidance of doubt, all of the parties to this Agreement acknowledge and agree that (i) as of the effective date of the Current Agreement, certain rights and obligations of the Sponsoring Companies or their predecessors under the Original Agreement were changed, modified or otherwise removed, (ii) to the extent that the rights of any Sponsoring Company or their predecessors were thereby changed, modified or otherwise removed as of the effective date of the Current Agreement, such Sponsoring Company may be entitled to rights under applicable law, regulation, rules or orders under the Federal Power Act or otherwise adopted by the Federal Energy Regulatory Commission ("FERC"), (iii) as a result of the elimination as of the effective date of the Current Agreement of the firm transmission service previously provided during the term of the Original Agreement to Sponsoring Companies or their predecessors whose transmission systems were only indirectly connected to the Corporation's facilities through intervening transmission systems by certain Sponsoring Companies or their predecessors whose transmission systems were directly connected to the Corporation's facilities, such Sponsoring Companies or their predecessors whose transmission systems were only indirectly connected to the Corporation's facilities through intervening transmission systems shall have been entitled to such "roll over" firm transmission service for delivery of their entitlement to their Power Participation Ratio share of Surplus Power and Surplus Energy under this Agreement, to the border of such Sponsoring Company system and intervening Sponsoring Company system, as would be accorded a longterm firm point-to-point transmission service reservation under the then otherwise applicable FERC Open Access Transmission Tariff ("OATT"), (iv) the obligation of any Sponsoring Company to maintain or expand transmission capacity to accommodate another Sponsoring Company's "roll over" rights to transmission service for delivery of their entitlement to their Power Participation Ratio share of Surplus Power and Surplus Energy under this Agreement shall be consistent with the obligations it would have for long-term firm point-to-point transmission service provided pursuant to the then otherwise applicable OATT, and (v) the parties shall cooperate with any Sponsoring Company that seeks to obtain and/or exercise any such rights available under applicable law, regulation, rules or orders under the Federal Power Act or otherwise adopted by the FERC.

- 9.07. Term of Agreement. This Agreement shall become effective upon the Effective Date and shall terminate upon the earlier of: (1) June 30, 2040 or (2) the sale or other disposition of all of the facilities of the Project Generating Stations or the permanent cessation of operation of such facilities; provided that, the provisions of Articles 5, 7 and 8, this Section 9.07 and Sections 9.08, 9.09, 9.10, 9.11, 9.12, 9.14, 9.15, 9.16, 9.17 and 9.18 shall survive the termination of this Agreement, and no termination of this Agreement, for whatever reason, shall release any Sponsoring Company of any obligations or liabilities incurred prior to such termination.
- 9.08. Access to Records. Corporation shall, at all reasonable times, upon the request of any Sponsoring Company, grant to its representatives reasonable access to the books, records and accounts of the Corporation, and furnish such Sponsoring Company such information as it may reasonably request, to enable it to determine the accuracy and reasonableness of payments made for energy supplied under this Agreement.
- 9.09. Modification of Agreement. Absent the agreement of all parties to this Agreement, the standard for changes to provisions of this Agreement related to rates proposed by a party, a non-party or the Federal Energy Regulatory Commission (or a successor agency) acting sua sponte shall be the "public interest" standard of review set forth in *United Gas Pipeline Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332 (1956) and *Federal Power Comm'n v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956).
- 9.10. Arbitration. Any controversy, dispute or claim arising out of this Agreement or the refusal by any party hereto to perform the whole or any part thereof, shall be determined by arbitration, in the City of Columbus, Franklin County, Ohio, in accordance with the Commercial Arbitration Rules of the American Arbitration Association or any successor organization, except as otherwise set forth in this Section 9.10.

The party demanding arbitration shall serve notice in writing upon all other parties hereto, setting forth in detail the controversy, dispute or claim with respect to which arbitration is demanded, and the parties shall thereupon endeavor to agree upon an arbitration board, which shall consist of three members ("Arbitration Board"). If all the parties hereto fail so to agree within a period of thirty (30) days from the original notice, the party demanding

arbitration may, by written notice to all other parties hereto, direct that any members of the Arbitration Board that have not been agreed to by the parties shall be selected by the American Arbitration Association, or any successor organization. No person shall be eligible for appointment to the Arbitration Board who is an officer, employee, shareholder of or otherwise interested in any of the parties hereto or in the matter sought to be arbitrated.

The Arbitration Board shall afford adequate opportunity to all parties hereto to present information with respect to the controversy, dispute or claim submitted to arbitration and may request further information from any party hereto; provided, however, that the parties hereto may, by mutual agreement, specify the rules which are to govern any proceeding before the Arbitration Board and limit the matters to be considered by the Arbitration Board, in which event the Arbitration Board shall be governed by the terms and conditions of such agreement.

The determination or award of the Arbitration Board shall be made upon a determination of a majority of the members thereof. The findings and award of the Arbitration Board shall be final and conclusive with respect to the controversy, dispute or claim submitted for arbitration and shall be binding upon the parties hereto, except as otherwise provided by law. The award of the Arbitration Board shall specify the manner and extent of the division of the costs of the arbitration proceeding among the parties hereto.

- 9.11. Liability. The rights and obligations of all the parties hereto shall be several and not joint or joint and several.
- 9.12. Force Majeure. No party hereto shall be held responsible or liable for any loss or damage on account of non-delivery of energy hereunder at any time caused by an event of Force Majeure. "Force Majeure" shall mean the occurrence or non-occurrence of any act or event that could not reasonably have been expected and avoided by exercise of due diligence and foresight and such act or event is beyond the reasonable control of such party, including to the extent caused by act of God, fire, flood, explosion, strike, civil or military authority, insurrection or riot, act of the elements, or failure of equipment. For the avoidance of doubt, "Force Majeure" shall in no event be based on any Sponsoring Company's financial or economic conditions, including without limitation (i) the loss of the Sponsoring Company's markets; or (ii) the Sponsoring Company's inability economically to use or resell the Available Power or Available Energy purchased hereunder.
- 9.13. Governing Law. This Agreement shall be governed by, and construed in accordance with, the laws of the State of Ohio.
- 9.14. Regulatory Approvals. This Agreement is made subject to the jurisdiction of any governmental authority or authorities having jurisdiction in the premises and the performance thereof shall be subject to the following:
  - (a) The receipt of all regulatory approvals, in form and substance satisfactory to Corporation, necessary to permit Corporation to perform all the duties and obligations to be performed by Corporation hereunder.

- (b) The receipt of all regulatory approvals, in form and substance satisfactory to the Sponsoring Companies, necessary to permit the Sponsoring Companies to carry out all transactions contemplated herein.
- 9.15. Notices. All notices, requests or other communications under this Agreement shall be in writing and shall be sufficient in all respects: (i) if delivered in person or by courier, upon receipt by the intended recipient or an employee that routinely accepts packages or letters from couriers or other persons for delivery to personnel at the address identified above (as confirmed by, if delivered by courier, the records of such courier), (ii) if sent by facsimile transmission, when the sender receives confirmation from the sending facsimile machine that such facsimile transmission was transmitted to the facsimile number of the addressee, or (iii) if mailed, upon the date of delivery as shown by the return receipt therefor.
- 9.16. Waiver. Performance by any party to this Agreement of any responsibility or obligation to be performed by such party or compliance by such party with any condition contained in this Agreement may by a written instrument signed by all other parties to this Agreement be waived in any one or more instances, but the failure of any party to insist in any one or more instances upon strict performance of any of the provisions of this Agreement or to take advantage of any of its rights hereunder shall not be construed as a waiver of any such provisions or the relinquishment of any such rights, but the same shall continue and remain in full force and effect.
- 9.17. Titles of Articles and Sections. The titles of the Articles and Sections in this Agreement have been inserted as a matter of convenience of reference and are not a part of this Agreement.
- 9.18. Successors and Assigns. This Agreement may be executed in any number of counterparts, all of which shall constitute but one and the same document.
  - 9.181 This Agreement shall inure to the benefit of and be binding upon the parties hereto and their respective successors and assigns, but a party to this Agreement may not assign this Agreement or any of its rights, title or interests in or obligations (including without limitation the assumption of debt obligations) under this Agreement, except to a successor to all or substantially all the properties and assets of such party or as provided in Section 9.182 or 9.183, without the written consent of all the other parties hereto.
  - 9.182 Notwithstanding the provisions of Section 9.181, any Sponsoring Company shall be permitted to, upon thirty (30) days notice to the Corporation and each other Sponsoring Company, without any further action by the Corporation or the other Sponsoring Companies, assign all or part of its rights, title and interests in, and obligations under this Agreement to a Permitted Assignee, provided that, the assignee and assignor of the rights, title and interests in, and obligations under, this Agreement have executed an assignment agreement in form and substance acceptable to the Corporation

in its reasonable discretion (including, without limitation; the agreement by the Sponsoring Company assigning such rights, title and interests in, and obligations under, this Agreement to reimburse the Corporation and the other Sponsoring Companies for any fees or expenses required under any security issued, or agreement entered into, by the Corporation as a result of such assignment, including without limitation any consent fee or additional financing costs to the Corporation under the Corporation's then-existing securities or agreements resulting from such assignment).

- 9.183 Notwithstanding the provisions of Section 9.181, any Sponsoring Company shall be permitted to, subject to compliance with all of the requirements of this Section 9.183, assign all or part of its rights, title and interests in, and obligations under this Agreement to a Third Party without any further action by the Corporation or the other Sponsoring Companies.
  - (a) A Sponsoring Company (the "Transferring Sponsor") that desires to assign all or part of its rights, title and interests in, and obligations under this Agreement to a Third Party shall deliver an Offer Notice to the Corporation and each other Sponsoring Company. The Offer Notice shall be deemed to be an irrevocable offer of the subject rights, title and interests in, and obligations under this Agreement to each of the other Sponsoring Companies that is not an Affiliate of the Transferring Sponsor, which offer must be held open for no less than thirty (30) days from the date of the Offer Notice (the "Election Period").
  - The Sponsoring Companies (other than the Transferring (b) Sponsor and its Affiliates) shall first have the right, but not the obligation, to purchase all of the rights, title and interests in, and obligations under this Agreement described in the Offer Notice at the price and on the terms specified therein by delivering written notice of such election to the Transferring Sponsor and the Corporation within the Election Period; provided that, irrespective of the terms and conditions of the Offer Notice, a Sponsoring Company may condition its election to purchase the interest described in the Offer Notice on the receipt of approval or consent from such Sponsoring Company's Board of Directors; provided further that, written notice of such conditional election must be delivered to the Transferring Sponsor and the Corporation within the Election Period and such conditional election shall be deemed withdrawn (as if it had never been provided) unless the Sponsoring Company that delivered such conditional election subsequently delivers written notice to the Transferring Sponsor and the Corporation on or before the tenth (10<sup>th</sup>) day after the expiration of the Election Period that all necessary approval or consent of such Sponsoring Company's Board of Directors have been obtained. To the extent that more than one Sponsoring Company exercises its right to purchase all of the rights, title and interests in, and

obligations under this Agreement described in the Offer Notice in accordance with the previous sentence, such rights, title and interests in, and obligations under this Agreement shall be allotted (successively if necessary) among the Sponsoring Companies exercising such right in proportion to their respective Power Participation Ratios.

- (c) Each Sponsoring Company exercising its right to purchase any rights, title and interests in, and obligations under this Agreement pursuant to this Section 9.183 may choose to have an Affiliate purchase such rights, title and interests in, and obligations under this Agreement; provided that, notwithstanding anything in this Section 9.183 to the contrary, any assignment to a Sponsoring Company or its Affiliate hereunder must comply with the requirements of Section 9.182.
- If one or more Sponsoring Companies have elected to purchase all of the rights, title and interests in, and obligations under this Agreement of the Transferring Sponsor pursuant to the Offer Notice, the assignment of such rights, title and interests in, and obligations under this Agreement shall be consummated as soon as practical after the delivery of the election notices, but in any event no later than fifteen (15) days after the filing and receipt, as applicable, of all necessary governmental filings. consents or other approvals and the expiration of all applicable waiting periods. At the closing of the purchase of such rights, title and interests in. and obligations under this Agreement from the Transferring Sponsor, the Transferring Sponsor shall provide representations and warranties customary for transactions of this type, including those as to its title to such securities and that there are no liens or other encumbrances on such securities (other than pursuant to this Agreement) and shall sign such documents as may reasonably be requested by the Corporation and the other Sponsoring Companies. The Sponsoring Companies or their Affiliates shall only be required to pay cash for the rights, title and interests in, and obligations under this Agreement being assigned by the Transferring Sponsor.
- (e) To the extent that the Sponsoring Companies have not elected to purchase all of the rights, title and interests in, and obligations under this Agreement described in the Offer Notice, the Transferring Sponsor may, within one-hundred and eighty (180) days after the later of the expiration of the Election Period or the deemed withdrawal of a conditional election by a Sponsoring Company under Section 9.183(b) hereof (if applicable), enter into a definitive agreement to, assign such rights, title and interests in, and obligations under this Agreement to a Third Party at a price no less than 92.5% of the purchase price specified in the Offer Notice and on other material terms and conditions no more

favorable to the such Third Party than those specified in the Offer Notice; provided that such purchases shall be conditioned upon: (i) such Third Party having long-term unsecured non-credit enhanced indebtedness, as of the date of such assignment, with a Standard & Poor's credit rating of at least BBB- and a Moody's Investors Service, Inc. credit rating of at least Baa3 (provided that, if such Third Party's long-term unsecured non-credit enhanced indebtedness is not currently rated by one of Standard & Poor's or Moody, such Third Party's long-term unsecured non-credit enhanced indebtedness, as of the date of such assignment, must have either a Standard & Poor's credit rating of at least BBB- or a Moody's Investors Service, Inc. credit rating of at least Baa3); (ii) the filing or receipt, as applicable, of any necessary governmental filings, consents or other approvals; (iii) the determination by counsel for the Corporation that the assignment of the rights, title or interests in, or obligations under, this Agreement to such Third Party would not cause a termination, default, loss or payment obligation under any security issued, or agreement entered into, by the Corporation prior to such transfer; and (iv) such Third Party executing a counterpart of this Agreement, and both such Third Party and the Sponsoring Company which is assigning its rights, title and interests in, and obligations under, this Agreement executing such other documents as may be reasonably requested by the Corporation (including, without limitation, an assignment agreement in form and substance acceptable to the Corporation in its reasonable discretion and containing the agreement by such Sponsoring Company to reimburse the Corporation and the other Sponsoring Companies for any fees or expenses required under any security issued, or agreement entered into, by the Corporation as a result of such assignment, including without limitation any consent fee or additional financing costs to the Corporation under the Corporation's thenexisting securities or agreements resulting from such assignment). In the event that the Sponsoring Company and a Third Party have not entered into a definitive agreement to assign the interests specified in the Offer Notice to such Third Party within the later of one-hundred and eighty (180) days after the expiration of the Election Period or the deemed withdrawal of a conditional election by a Sponsoring Company under Section 9.183(b) hereof (if applicable) for any reason or if either the price to be paid by such Third Party would be less than 92.5% of the purchase price specified in the Offer Notice or the other material terms of such assignment would be more favorable to such Third Party than the terms specified in the Offer Notice, then the restrictions provided for herein shall again be effective, and no assignment of any rights, title and interests in, and obligations under this Agreement may be made thereafter without again offering the same to Sponsoring Companies in accordance with this Section 9.183.

### ARTICLE 10

#### REPRESENTATIONS AND WARRANTIES

10.01. Representations and Warranties. Each Sponsoring Company hereby represents and warrants for itself, on and as of the date of this Agreement, as follows:

- (a) it is duly organized, validly existing and in good standing under the laws of its state of organization, with full corporate power, authority and legal right to execute and deliver this Agreement and to perform its obligations hereunder;
- (b) it has duly authorized, executed and delivered this Agreement, and upon the execution and delivery by all of the parties hereto, this Agreement will be in full force and effect, and will constitute a legal, valid and binding obligation of such Sponsoring Company, enforceable in accordance with the terms hereof, except as enforceability may be limited by applicable bankruptcy, insolvency, fraudulent conveyance, reorganization, moratorium or other similar laws affecting the enforcement of creditors' rights generally;
- (c) Except as set forth in <u>Schedule 10.01(c)</u> hereto, no consents or approvals of, or filings or registrations with, any governmental authority or public regulatory authority or agency, federal state or local, or any other entity or person are required in connection with the execution, delivery and performance by it of this Agreement, except for those which have been duly obtained or made and are in full force and effect, have not been revoked, and are not the subject of a pending appeal; and
- (d) the execution, delivery and performance by it of this Agreement will not conflict with or result in any breach of any of the terms, conditions or provisions of, or constitute a default under its charter or by-laws or any indenture or other material agreement or instrument to which it is a party or by which it may be bound or result in the imposition of any liens, claims or encumbrances on any of its property.

## ARTICLE 11

#### EVENTS OF DEFAULT AND REMEDIES

11.01. Payment Default. If any Sponsoring Company fails to make full payment to Corporation under this Agreement when due and such failure is not remedied within ten (10) days after receipt of notice of such failure from the Corporation, then such failure shall constitute a "Payment Default" on the part of such Sponsoring Company. Upon a Payment Default, the

Corporation may suspend service to the Sponsoring Company that has caused such Payment Default for all or part of the period of continuing default (and such Sponsoring Company shall be deemed to have notified the Corporation and the other Sponsoring Companies that any Available Energy shall be available for scheduling by such other Sponsoring Companies in accordance with Section 4.032). The Corporation's right to suspend service shall not be exclusive, but shall be in addition to all remedies available to the Corporation at law or in equity. No suspension of service or termination of this Agreement shall relieve any Sponsoring Company of its obligations under this Agreement, which are absolute and unconditional.

11.02. Performance Default. If the Corporation or any Sponsoring Company fails to comply in any material respect with any of the material terms, conditions and covenants of this Agreement (and such failure does not constitute a Payment Default under Section 11.01), the Corporation (in the case of a default by any Sponsoring Company) and any Sponsoring Company (in the case of a default by the Corporation) shall give the defaulting party written notice of the default ("Performance Default"). To the extent that a Performance Default is not cured within thirty (30) days after receipt of notice thereof (or within such longer period of time, not to exceed sixty (60) additional days, as necessary for the defaulting party with the exercise of reasonable diligence to cure such default), then the Corporation (in the case of a default by any Sponsoring Company) and any Sponsoring Company (in the case of a default by the Corporation) shall have all of the rights and remedies provided at law and in equity, other than termination of this Agreement or any release of the obligation of the Sponsoring Companies to make payments pursuant to this Agreement, which obligation shall remain absolute and unconditional.

11.03. Waiver. No waiver by the Corporation or any Sponsoring Company of any one or more defaults in the performance of any provision of this Agreement shall be construed as a waiver of any other default or defaults, whether of a like kind or different nature.

11.04. Limitation of Liability and Damages. TO THE FULLEST EXTENT PERMITTED BY LAW, NEITHER THE CORPORATION, NOR ANY SPONSORING COMPANY SHALL BE LIABLE UNDER THIS AGREEMENT FOR ANY CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST REVENUES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, OR OTHERWISE.

[Signature pages follow]

OHIO VALLEY ELECTRIC CORPORATION	ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.
By Muholfhours Its	By
APPALACHIAN POWER COMPANY	BUCKEYE POWER GENERATING LLC
By	By
COLUMBUS SOUTHERN POWER COMPANY	THE DAYTON POWER AND LIGHT COMPANY
By Its	By
DUKE ENERGY OHIO, INC.	FIRSTENERGY GENERATION CORP.
By Its	By Its
INDIANA MICHIGAN POWER COMPANY	KENTUCKY UTILITIES COMPANY
By Its	By Its

Amended and Restated Inter-Company Power Agreement

OHIO VALLEY ELECTRIC CORPORATION	ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.
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Amended and Restated Inter-Company Power Agreement

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Amended and Restated Inter-Company Power Agreement 5-1

OHIO VALLEY ELECTRIC CORPORATION	ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.
By	By
APPALACHIAN POWER COMPANY	BUCKEYE POWER GENERATING LLC
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INDIANA MICHIGAN POWER COMPANY	KENTUCKY UTILITIES COMPANY
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OHIO VALLEY ELECTRIC CORPORATION	ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.
By	By
APPALACHIAN POWER COMPANY	BUCKEYE POWER GENERATING LLC
By	By
COLUMBUS SOUTHERN POWER COMPANY	THE DAYTON POWER AND LIGHT COMPANY
By	By
DUKE ENERGY OHIO, INC.	FIRSTENERGY GENERATION CORP.
By	By
INDIANA MICHIGAN POWER COMPANY	KENTUCKY UTILITIES COMPANY
By My by Surs Its Vin President	By

Amended and Restated Inter-Company Power Agreement

OHIO VALLEY ELECTRIC CORPORATION	ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.
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APPALACHIAN POWER COMPANY	BUCKEYE POWER GENERATING LLC
By	By
COLUMBUS SOUTHERN POWER COMPANY	THE DAYTON POWER AND LIGHT COMPANY
By	By
DUKE ENERGY OHIO, INC.	FIRSTENERGY GENERATION CORP.
By	By
INDIANA MICHIGAN POWER COMPANY	KENTUCKY UTILITIES COMPANY
By	By

Amended and Restated Inter-Company Power Agreement

IN WITNESS WHEREOF, the parties hereto have caused this Amended and Restated Inter-Company Power Agreement to be duly executed and delivered by their proper and duly authorized officers as of September 10, 2010.

OHIO VALLEY ELECTRIC CORPORATION	ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.
By	By
APPALACHIAN POWER COMPANY	BUCKEYE POWER GENERATING
By Its	By Inthony I alern Its President & CEO
COLUMBUS SOUTHERN POWER COMPANY	THE DAYTON POWER AND LIGHT COMPANY
By Its	By Its
DUKE ENERGY OHIO, INC.	FIRSTENERGY GENERATION CORP.
By	ByIts
INDIANA MICHIGAN POWER COMPANY	KENTUCKY UTILITIES COMPANY
By	By

IN WITNESS WHEREOF, the parties hereto have caused this Amended and Restated Inter-Company Power Agreement to be duly executed and delivered by their proper and duly authorized officers as of September 10, 2010.

OHIO VALLEY ELECTRIC CORPORATION	ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.
By	By
APPALACHIAN POWER COMPANY	BUCKEYE POWER GENERATING, LLC
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DUKE ENERGY OHIO, INC.	FIRSTENERGY GENERATION CORP.
By	By Its
INDIANA MICHIGAN POWER COMPANY	KENTUCKY UTILITIES COMPANY
By	By

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OHIO VALLEY ELECTRIC CORPORATION	ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.
By	By
APPALACHIAN POWER COMPANY.	BUCKEYE POWER GENERATING, LLC
By	By
COLUMBUS SOUTHERN POWER COMPANY	THE DAYTON POWER AND LIGHT COMPANY
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duke energy ohio, inc.	FIRSTENERGY GENERATION CORP.
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INDIANA MICHIGAN POWER COMPANY	KENTUCKY UTILITIES COMPANY
By	By

IN WITNESS WHEREOF, the parties hereto have caused this Amended and Restated Inter-Company Power Agreement to be duly executed and delivered by their proper and duly authorized officers as of September 10, 2010.

OHIO VALLEY ELECTRIC CORPORATION	ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.
By Its	By
APPALACHIAN POWER COMPANY	BUCKEYE POWER GENERATING LLC
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OHIO POWER COMPANY	SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
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COMPANY	MONONGAHELA POWER COMPANY
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OHIO POWER COMPANY	SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
By Its	By Conald E. Christian Its Associat

PENINSULA GENERATION COOPERATIVE

By Daniel H. DeCoeur

Its President

APPROVED AS TO FORM:

BRIAN E. VALICE ATTORNEY FOR PENINSULA GENERATION COOPERATIVE

## Allegheny Energy Supply Company, L.L.C.

and

## Monongahela Power Company

## Appalachian Power Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

Approval of the Virginia State Corporation Commission

Filing with the Public Service Commission of West Virginia

**Buckeye Power Generating, LLC** 

None

## Columbus Southern Power Company

## The Dayton Power and Light Company

## Duke Energy Ohio, Inc.

## FirstEnergy Generation Corp.

## Indiana Michigan Power Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

Filing with the Indiana Utility Regulatory Commission

## Kentucky Utilities Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

Consent or approval of, or filings or registrations with, the Kentucky Public Service Commission may be required

## Louisville Gas and Electric Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

Consent or approval of, or filings or registrations with, the Kentucky Public Service Commission may be required

## **Ohio Power Company**

Peninsula Generation Cooperative

None

## Southern Indiana Gas and Electric Company

Exhibit KMM-3

## **ANNUAL REPORT — 2012**

**OHIO VALLEY ELECTRIC CORPORATION** 

and subsidiary

INDIANA-KENTUCKY ELECTRIC CORPORATION

## Ohio Valley Electric Corporation

GENERAL OFFICES, 3932 U.S. Route 23, Piketon, Ohio 45661

Ohio Valley Electric Corporation (OVEC) and its wholly owned subsidiary, Indiana-Kentucky Electric Corporation (IKEC), collectively, the Companies, were organized on October 1, 1952. The Companies were formed by investor-owned utilities furnishing electric service in the Ohio River Valley area and their parent holding companies for the purpose of providing the large electric power requirements projected for the uranium enrichment facilities then under construction by the Atomic Energy Commission (AEC) near Portsmouth, Ohio.

OVEC, AEC and OVEC's owners or their utility-company affiliates (called Sponsoring Companies) entered into power agreements to ensure the availability of the AEC's substantial power requirements. On October 15, 1952, OVEC and AEC executed a 25-year agreement, which was later extended through December 31, 2005 (DOE Power Agreement). On September 29, 2000, the DOE gave OVEC notice of cancellation of the DOE Power Agreement. On April 30, 2003, the DOE Power Agreement terminated in accordance with the notice of cancellation.

OVEC and the Sponsoring Companies signed an Inter-Company Power Agreement (ICPA) on July 10, 1953, to support the DOE Power Agreement and provide for excess energy sales to the Sponsoring Companies of power not utilized by the DOE or its predecessors. Since the termination of the DOE Power Agreement on April 30, 2003, OVEC's entire generating capacity has been available to the Sponsoring Companies under the terms of the ICPA. The Sponsoring Companies and OVEC entered into an Amended and Restated ICPA, effective as of August 11, 2011, which extends its term to June 30, 2040.

OVEC's Kyger Creek Plant at Cheshire, Ohio, and IKEC's Clifty Creek Plant at Madison, Indiana, have nameplate generating capacities of 1,086,300 and 1,303,560 kilowatts, respectively. These two generating stations, both of which began operation in 1955, are connected by a network of 705 circuit miles of 345,000-volt transmission lines. These lines also interconnect with the major power transmission networks of several of the utilities serving the area.

The current Shareholders and their respective percentages of equity in OVEC are:

Allegheny Energy, Inc. 1	3.50
American Electric Power Company, Inc.*	39.17
Buckeye Power Generating, LLC <sup>2</sup>	18.00
The Dayton Power and Light Company <sup>3</sup>	4.90
Duke Energy Ohio, Inc. <sup>4</sup>	9.00
Kentucky Utilities Company <sup>5</sup>	2.50
Louisville Gas and Electric Company <sup>5</sup>	5.63
Ohio Edison Company <sup>1</sup>	0.85
Ohio Power Company** <sup>6</sup>	4.30
Peninsula Generation Cooperative <sup>7</sup>	6.65
Southern Indiana Gas and Electric Company <sup>8</sup>	1.50
The Toledo Edison Company <sup>1</sup>	_4.00
	<u>100.00</u>

These investor-owned utilities comprise the Sponsoring Companies and currently share the OVEC power participation benefits and requirements in the following percentages:

Allegheny Energy Supply Company LLC <sup>1</sup>	3.01
Appalachian Power Company <sup>6</sup>	15.69
Buckeye Power Generating, LLC <sup>2</sup>	18.00
The Dayton Power and Light Company <sup>3</sup>	4.90
Duke Energy Ohio, Inc. <sup>4</sup>	9.00
FirstEnergy Generation, LLC <sup>1</sup>	4.85
Indiana Michigan Power Company <sup>6</sup>	7.85
Kentucky Utilities Company <sup>5</sup>	2.50
Louisville Gas and Electric Company <sup>5</sup>	5.63
Monongahela Power Company <sup>1</sup>	0.49
Ohio Power Company <sup>6</sup>	19.93
Peninsula Generation Cooperative <sup>7</sup>	6.65
Southern Indiana Gas and Electric Company <sup>8</sup>	1.50
•	100.00

Some of the Common Stock issued in the name of:

Subsidiary or affiliate of:

<sup>1</sup>FirstEnergy Corp.

<sup>2</sup>Buckeye Power, Inc.

<sup>3</sup>The AES Corporation

<sup>4</sup>Duke Energy Corporation

<sup>5</sup>PPL Corporation

<sup>6</sup>American Electric Power Company, Inc.

<sup>7</sup>Wolverine Power Supply Cooperative, Inc.

<sup>8</sup>Vectren Corporation

<sup>\*</sup>American Gas & Electric Company

<sup>\*\*</sup>Columbus and Southern Ohio Electric Company

# OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

## A Message from the President

Ohio Valley Electric Corporation and its subsidiary, Indiana-Kentucky Electric Corporation, observed their 60<sup>th</sup> anniversary as corporate entities on October 1, 2012. Over the years, the companies' long-established competitive operating efficiency and performance have proved to be valuable to our owners, the Sponsoring Companies. Going forward, we will continue to focus on our values — safety, operational excellence, cost controls and environmental compliance.

#### FLUE GAS DESULFURIZATION (FGD) PROJECTS

The first FGD scrubber at Kyger Creek was successfully placed into service in November 2011, and the second Kyger FGD scrubber began successful operation in February 2012. Both scrubbers continue to meet our environmental performance expectations. As designed, the Kyger Creek scrubbers achieve 98 percent sulfur dioxide (SO<sub>2</sub>) removal efficiency.

The first Clifty Creek plant FGD system was successfully placed into service in March 2013, and the second FGD system began successful operation in May 2013. These FGDs are also designed to achieve 98 percent SO<sub>2</sub> removal efficiency, and initial data shows that the Clifty Creek FGD systems will perform as designed.

#### **ENERGY SALES**

OVEC's use factor — the ratio of power scheduled by the Sponsoring Companies to power available — for the combined on- and off-peak periods averaged 69.4 percent in 2012 compared with 89.6 percent in 2011. The on-peak use factor averaged 82.9 percent in 2012 compared with 98.9 percent in 2011. The off-peak use factor averaged 52.4 percent in 2012 and 77.5 percent in 2011.

In 2012, OVEC delivered 10.34 million MWh to the Sponsoring Companies compared with 14.20 million MWh in 2011.

#### **POWER COSTS**

In 2012, OVEC's average power cost to the Sponsoring Companies was \$62.86 per MWh compared with \$50.86 per MWh in 2011. The total Sponsoring Company power costs were \$650 million in 2012 compared with \$722 million in 2011. The lower energy sales in 2012 accounted for the majority of the increase in the cost per MWh in 2012. Mild weather, a soft energy market and low-cost natural gas generation were responsible for lower energy sales in 2012.

#### 2013 ENERGY SALES OUTLOOK

In 2013, the demand for energy remains weak as the national economy continues to recover and natural gas generation continues to compete with coal-fired generation. OVEC projects that these factors will continue to impact the Sponsors' scheduling of OVEC's power in 2013. As a result, OVEC anticipates the combined use factor for 2013 will be approximately 75 percent.

#### **COST CONTROL INITIATIVES**

In 2012 and continuing in 2013, OVEC has been engaged in a continuous improvement initiative to control costs, improve operating performance and explore opportunities to enhance the value of the OVEC investment. This work will produce sustainable savings through OVEC's partnering with the workforce in forming change management teams.

#### **AVAILABILITY**

In 2012, the combined equivalent availability of the five generating units at Kyger Creek and the six units at Clifty Creek was 78.9 percent compared with 83.0 percent in 2011.

#### **OVEC FERC ORDER 1000 COMPLIANCE**

The Federal Energy Regulatory Commission (FERC) Order 1000 issued in July 2011 requires transmission providers, including OVEC, to participate in regional and interregional transmission planning. Because OVEC is not a member of a Regional Transmission Organization that provides such planning to its members, OVEC partnered with LG&E/KU to join the Southeast Regional Transmission Planning (SERTP) group. The SERTP had been formed in 2007 by a group of utilities led by Southern Company. Working with this group, OVEC was able to submit a compliance filing to the FERC for the regional planning portion of Order 1000 in February 2013. A ruling on this filing is expected from the FERC later this summer. OVEC is currently working with the SERTP on developing a filing to address the interregional portion of Order 1000. As it did for the regional filing, the FERC has granted an extension of the interregional filing date from April until July 2013.

#### DOE ARRANGEMENTS WITH OVEC

In 2012, OVEC purchased 245,994 MWh of power and energy from other electricity suppliers for delivery and use by the Department of Energy (DOE) for its Portsmouth facility. At the request of the DOE, OVEC makes these limited purchases of power and energy under the terms and conditions of an Arranged Power Agreement with the DOE.

As ordered by the FERC, the North American Electric Reliability Corporation (NERC) registered OVEC as the load-serving entity for the DOE load at the Portsmouth facility. OVEC is working with Sponsor representatives to mitigate any impacts, other than additional NERC compliance obligation, that could result from this additional NERC registration. Discussions continue with the DOE on assuming responsibility for the remaining high-voltage substation at the facility.

#### **ENVIRONMENTAL COMPLIANCE**

OVEC and IKEC have a strong commitment to maintain compliance with all applicable federal, state and local environmental rules and regulations. During 2012, the Kyger Creek and Clifty Creek plants operated in compliance with their respective air emission limits, and the Companies received no notices of violation from any of the environmental

agencies responsible for overseeing the status of our environmental compliance activities.

#### **SAFETY**

OVEC and IKEC are committed to providing a safe and healthy place to work for all employees. In 2012, the Companies continued making progress on their transition to a culture that leads with safety. Safety training on Human Performance Improvement tools was initiated in 2012 and will continue in 2013. Strong leadership and the involvement of all employees will help ensure that we achieve and sustain the desired goal of zero harm.

#### **BOARD OF DIRECTORS AND OFFICERS CHANGES**

In December 2012, James R. Haney, vice president, compliance & regulated services and chief FERC compliance officer of FirstEnergy Services Company, was elected to serve as a director of OVEC following the resignation of Stanley F. Szwed. Also in December 2012, Charles D. Lasky, vice president, fossil fleet operations of FirstEnergy Generation, LLC, was elected a director of IKEC and appointed to the Executive Committee of OVEC and IKEC. succeeding Stanley F. Szwed. Mr. Szwed had served on the OVEC and IKEC boards and as a member of the Executive Committee of both companies since 2003. Effective March 1, 2013, Lana L. Hillebrand, senior vice president and chief administrative officer of American Electric Power Company, Inc., was elected a director of OVEC and a member of the OVEC Human Resources Committee, replacing Pablo A. Vegas. Mr. Vegas had served on the OVEC board and as a member of the Human Resources Committee since 2012.

In January 2013, Julie Sloat, senior vice president and treasurer for American Electric Power Company, Inc., was elected assistant secretary and assistant treasurer of OVEC and IKEC.

Hetale & Colors

Nicholas K. Akins President

June 24, 2013

# OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2012 AND 2011

	2012	2011
ASSETS		
ELECTRIC PLANT:		
At original cost	\$1,985,645,118	\$1,782,236,938
Less — accumulated provisions for depreciation	1,115,363,691	1,041,198,318
2000 accommended provisions for depreciation	1,113,303,071	1,041,170,310
	870,281,427	741,038,620
Construction in progress	645,484,896	684,076,875
Total electric plant	1,515,766,323	1,425,115,495
CURRENT ASSETS:		
Cash and cash equivalents	19,924,318	4,752,223
Accounts receivable	36,952,825	40,901,450
Fuel in storage	79,550,095	71,696,998
Materials and supplies	27,464,418	27,805,915
Property taxes applicable to future years	2,503,440	2,521,920
Emission allowances	86,649	28,519
Deferred tax assets	18,302,793	13,213,395
Income taxes receivable	15,832,666	1,441,451
Regulatory assets	8,277,357	
Prepaid expenses and other	2,168,143	1,907,652
Total current assets	211,062,704	164,269,523
REGULATORY ASSETS:		
Unrecognized postemployment benefits	2 408 750	2 412 695
Pension benefits	2,498,759 30,561,325	2,412,685 50,922,795
Postretirement benefits	1,324,775	2,980,610
1 Ostromont bonomb	1,324,773	2,980,010
Total regulatory assets	34,384,859	56,316,090
DEFERRED CHARGES AND OTHER:		
Unamortized debt expense	14,485,787	13,714,625
Deferred tax assets	22,265,884	31,902,804
Long-term investments	120,351,712	106,177,206
Special deposits - restricted	57,938,752	100,177,200
Other	103,107	222,482
omor	103,107	
Total deferred charges and other	215,145,242	152,017,117
TOTAL	\$1,976,359,128	\$1,797,718,225
		(Continued)

# OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

CONSOLIDATED BALANCE SHEETS AS OF DECEMBER 31, 2012 AND 2011

CADITAL IZATION AND LIADUITIES	2012	2011
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION:		
Common stock, \$100 par value — authorized, 300,000 shares;		
outstanding, 100,000 shares in 2012 and 2011	\$ 10,000,000	\$ 10,000,000
Long-term debt	1,358,347,337	1,197,204,828
Line of credit borrowings	60,000,000	100,000,000
Retained earnings	5,293,968	4,037,278
Total capitalization	1,433,641,305	1,311,242,106
CURRENT LIABILITIES:		
Current portion of long-term debt	238,138,903	135,797,658
Accounts payable	53,916,997	78,722,972
Deferred revenue — advances for construction	19,389,380	31,084,284
Accrued other taxes	8,651,108	8,811,972
Regulatory liabilities	2,586,594	2,973,856
Accrued interest and other	25,822,574	22,909,899
Total current liabilities	348,505,556	280,300,641
COMMITMENTS AND CONTINGENCIES (Note 13)		
REGULATORY LIABILITIES:		
Decommissioning and demolition	14,230,459	10,610,565
Investment tax credits	3,393,146	3,393,146
Net antitrust settlement	1,823,929	1,823,929
Income taxes refundable to customers	38,645,647	40,284,930
Total regulatory liabilities	58,093,181	56 112 570
Total regulatory haddrities	36,093,161	56,112,570
OTHER LIABILITIES:		
Pension liability	30,561,325	50,922,795
Asset retirement obligations	20,961,379	19,809,316
Postretirement benefits obligation	82,097,623	76,918,112
Postemployment benefits obligation	2,498,759	2,412,685
Total other liabilities	136,119,086	150,062,908
TOTAL	\$1,976,359,128	\$1,797,718,225
See notes to consolidated financial statements.		(Concluded)

# OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

## CONSOLIDATED STATEMENTS OF INCOME AND RETAINED EARNINGS FOR THE YEARS ENDED DECEMBER 31, 2012 AND 2011

	2012	2011
OPERATING REVENUES — Sales of electric energy to:		
Department of Energy	\$ 9.097.306	ው 11 <i>ርላጋ ንናና</i>
Sponsoring Companies	\$ 9,097,306 661,721,951	\$ 11,643,355
Sponsoring Companies	001,721,931	705,294,774
Total operating revenues	670,819,257	716,938,129
OPERATING EXPENSES:		
Fuel and emission allowances consumed in operation	302,925,697	397,543,208
Purchased power	8,552,565	10,912,769
Other operation	101,967,242	95,597,681
Maintenance	89,645,354	81,451,764
Depreciation	85,140,820	56,131,434
Taxes — other than income taxes	10,765,327	11,207,820
Income taxes	893,533	851,608
	<del></del>	
Total operating expenses	599,890,538	653,696,284
OPERATING INCOME	70,928,719	63,241,845
OTHER INCOME	10,920,111	10,167,078
INCOME BEFORE INTEREST CHARGES	81,848,830	73,408,923
INTEREST CHARGES:		
Amortization of debt expense	4,606,617	1,478,943
Interest expense	74,985,523	69,259,876
· · · · · · · · · · · · · · · · · · ·		
Total interest charges	79,592,140	70,738,819
NET INCOME	2,256,690	2,670,104
RETAINED EARNINGS — Beginning of year	4,037,278	2,367,174
CASH DIVIDENDS ON COMMON STOCK	(1,000,000)	(1,000,000)
RETAINED EARNINGS — End of year	\$ 5,293,968	\$ 4,037,278

See notes to consolidated financial statements.

# OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

### CONSOLIDATED STATEMENTS OF CASH FLOWS FOR THE YEARS ENDED DECEMBER 31, 2012 AND 2011

	2012	2011
OPERATING ACTIVITIES:		
Net income	\$ 2,256,690	\$ 2,670,104
Adjustments to reconcile net income to net cash provided by (used in) operating activities:		
Depreciation	85,140,820	56,131,434
Amortization of debt expense Deferred taxes/refundable taxes	4,606,617	1,478,943
(Gain) on marketable securities	2,908,239	(1,236,767)
Changes in assets and liabilities:	(6,345,075)	(5,844,074)
Accounts receivable	2.040.626	2.515.000
Fuel in storage	3,948,625	3,517,008
Materials and supplies	(7,853,097)	(8,859,671)
Property taxes applicable to future years	341,497	(4,853,014)
Emission allowances	18,480	(19,920)
Income taxes receivable	(58,130)	612,810
Prepaid expenses and other	(14,391,215) (260,491)	12,430,808
Other regulatory assets	11,638,471	496,868 (43,323,464)
Other assets	11,030,471	(117,906)
Other noncurrent assets	119,375	(222,242)
Accounts payable	2,571,729	13,822,449
Deferred revenue - advances for construction	(11,694,904)	16,858,709
Accrued taxes	(160,864)	299,402
Accrued interest and other	2,912,675	235,410
Other liabilities	(13,943,822)	61,025,439
Other regulatory liabilities	5,248,035	(8,904,125)
Net cash provided by operating activities	67,003,655	96,198,201
INVESTING ACTIVITIES:		
Electric plant additions	(203,169,352)	(151 562 120)
Proceeds from sale of LT investments	20,342,154	(151,562,139) 26,095,488
Purchases of long-term investments	(86,110,337)	(38,955,548)
Net cash used in investing activities	(268,937,535)	(164,422,199)
FINANCING ACTIVITIES:		
Issuance of Senior 2012 Bonds	000 400 000	
Issuance of Senior 2010 Bonds	299,403,938	-
Loan origination cost	- (5.255.550)	100,000,000
Repayment of Senior 2006 Notes	(5,377,779)	(3,807,975)
Repayment of Senior 2007 Notes	(14,730,774)	(15,842,599)
Repayment of Senior 2008 Notes	(10,392,343)	(10,524,555)
Proceeds from line of credit	(10,797,067)	(12,853,086)
Payments on line of credit	160,000,000 (200,000,000)	80,000,000
Dividends on common stock	(1,000,000)	(85,000,000) (1,000,000)
Net cash provided by financing activities	217,105,975	50,971,785
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	15,172,095	(17,252,213)
CASH AND CASH EQUIVALENTS — Beginning of year	4,752,223	22,004,436
CASH AND CASH EQUIVALENTS — End of year	\$ 19,924,318	\$ 4,752,223
CLIDDLE MENTE AL DICCLOCUDE C		
SUPPLEMENTAL DISCLOSURES: Interest paid	\$ 74,160,307	\$ 69,615,825
Income taxes paid (received) — net	\$ 12,504,500	\$ (7,486,412)
Non-cash electric plant additions included in accounts payable at December 31	\$ 8,654,116	\$ 36,031,820
See notes to consolidated financial statements.		

## OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2012 AND 2011

#### 1. ORGANIZATION AND SIGNIFICANT ACCOUNTING POLICIES

Consolidated Financial Statements — The consolidated financial statements include the accounts of Ohio Valley Electric Corporation (OVEC) and its wholly owned subsidiary, Indiana-Kentucky Electric Corporation (IKEC), collectively, the Companies. All intercompany transactions have been eliminated in consolidation.

Organization — The Companies own two generating stations located in Ohio and Indiana with a combined electric production capability of approximately 2,256 megawatts. OVEC is owned by several investor-owned utilities or utility holding companies and two affiliates of generation and transmission rural electric cooperatives. These entities or their affiliates comprise the Sponsoring Companies. The Sponsoring Companies purchase power from OVEC according to the terms of the Inter-Company Power Agreement (ICPA), which has a current termination date of June 30, 2040. Approximately 27% of the Companies' employees are covered by a collective bargaining agreement that expires August 31, 2014.

Prior to 2004, OVEC's primary commercial customer was the U.S. Department of Energy (DOE). The contract to provide OVEC-generated power to the DOE was terminated in 2003 and all obligations were settled at that time. Currently, OVEC has an agreement to arrange for the purchase of power (Arranged Power), under the direction of the DOE, for resale directly to the DOE. All purchase costs are billable by OVEC to the DOE.

Rate Regulation — The proceeds from the sale of power to the Sponsoring Companies are designed to be sufficient for OVEC to meet its operating expenses and fixed costs, as well as earn a return on equity before federal income taxes. In addition, the proceeds from power sales are designed to cover debt amortization and interest expense associated with financings. The Companies have continued and expect to continue to operate pursuant to the cost plus rate of return recovery provisions at least to June 30, 2040, the date of termination of the ICPA.

The accounting guidance for Regulated Operations provides that rate-regulated utilities account for and report assets and liabilities consistent with the economic effect of the way in which rates are established, if the rates established are designed to recover the costs of providing the regulated service and it is probable that such rates can be charged and collected. The Companies follow the accounting and reporting requirements in accordance with the guidance for Regulated Operations. Certain expenses and credits subject to utility regulation or rate determination normally reflected in income are deferred on the accompanying consolidated balance sheets and are recognized in income as the related amounts are included in service rates and recovered from or refunded to customers.

# OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

### NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2012 AND 2011

The Companies' regulatory assets, liabilities, and amounts authorized for recovery through Sponsor billings at December 31, 2012 and 2011, were as follows:

	2012	2011
Regulatory assets:		
Current assets:		
Lease termination costs/liquidated damages	\$ 5,225,467	\$ -
Unrecognized loss on coal sales	3,051,890	
Total	8,277,357	
Other assets:		
Unrecognized postemployment benefits	\$ 2,498,759	\$ 2,412,685
Pension benefits	30,561,325	50,922,795
Postretirement benefits	1,324,775	2,980,610
Total	34,384,859	56,316,090
Total regulatory assets	\$42,662,216	\$56,316,090
Regulatory liabilities:		
Current liabilities:		
Deferred credit — EPA emission allowance proceeds Advance collection of interest	\$ 274,687 	\$ 269,506 2,704,350
Total	2,586,594	2,973,856
	<del></del>	
Other liabilities:		
Decommissioning and demolition	\$14,230,459	\$10,610,565
Investment tax credits	3,393,146	3,393,146
Net antitrust settlement	1,823,929	1,823,929
Income taxes refundable to customers	38,645,647	40,284,930
Total	58,093,181	56,112,570
Total regulatory liabilities	\$60,679,775	\$59,086,426

Regulatory Assets — Regulatory assets consist primarily of postretirement benefits, income taxes billable to customers, and pension benefits. Income taxes billable to customers are billed to customers in the period when the related deferred tax liabilities are realized. The fuel related costs, including railcar lease

## OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2012 AND 2011

termination costs and liquidated damages, will be billed to customers in 2013. All other regulatory assets are being recovered on a long-term basis.

Regulatory Liabilities —The regulatory liabilities classified as current in the accompanying consolidated balance sheet as of December 31, 2012, consist primarily of interest expense collected from customers in advance of expense recognition. These amounts outstanding will be credited to customer bills during 2013. Other regulatory liabilities consist primarily of income taxes refundable to customers, postretirement benefits, and decommissioning and demolition costs. Income taxes refundable to customers are credited to customer bills in the period when the related deferred tax assets are realized. The Companies' current ratemaking policy recovers postretirement benefits in an amount equal to estimated benefit accrual cost plus amortization of unfunded liabilities, if any. As a result, related regulatory liabilities are being credited to customer bills on a long-term basis. The remaining regulatory liabilities are awaiting credit to customer bills in a future period that is yet to be determined.

In 2003, the DOE terminated the DOE Power Agreement with OVEC, entitling the Sponsoring Companies to 100% of OVEC's generating capacity under the terms of the ICPA. Under the terms of the DOE Power Agreement, OVEC was entitled to receive a "termination payment" from the DOE to recover unbilled costs upon termination of the agreement. The termination payment included unbilled postretirement benefit costs. In 2003, OVEC recorded a settlement payment of \$97 million for the DOE obligation related to postretirement benefit costs. The regulatory liability for postretirement benefits recorded at December 31, 2012 and December 31, 2011, represents amounts collected in historical billings in excess of the Generally Accepted Accounting Principles net periodic benefit costs, including the DOE termination payment.

Cash and Cash Equivalents — Cash and cash equivalents primarily consist of cash and money market funds and their carrying value approximates fair value. For purposes of these statements, the Companies consider temporary cash investments to be cash equivalents since they are readily convertible into cash and have original maturities of less than three months.

Electric Plant — Property additions and replacements are charged to utility plant accounts. Depreciation expense is recorded at the time property additions and replacements are billed to customers or at the date the property is placed in service if the in-service date occurs subsequent to the customer billing. Customer billings for construction in progress are recorded as deferred revenue-advances for construction. These amounts are closed to revenue at the time the related property is placed in service. Depreciation expense and accumulated depreciation are recorded when financed property additions and replacements are recovered over a period of years through customer debt retirement billing. All depreciable property will be fully billed and depreciated prior to the expiration of the ICPA. Repairs of property are charged to maintenance expense.

Fuel in Storage, Emission Allowances, and Materials and Supplies — The Companies maintain coal, reagent, and oil inventories for use in the generation of electricity and emission allowance inventories for regulatory compliance purposes due to the generation of electricity. These inventories are valued at average cost, less reserves for obsolescence. Materials and supplies consist primarily of replacement parts necessary to maintain the generating facilities and are valued at average cost.

# OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

### NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2012 AND 2011

Long-Term Investments — Long-term investments consist of marketable securities that are held for the purpose of funding postretirement benefits and decommissioning and demolition costs. These securities have been classified as trading securities in accordance with the provisions of Investments — Debt and Equity Securities accounting guidance. Trading securities reflected in Long-Term Investments are carried at fair value with the unrealized gain or loss, reported in Other Income. The cost of securities sold is based on the specific identification cost method. The fair value of most investment securities is determined by reference to currently available market prices. Where quoted market prices are not available, we use the market price of similar types of securities that are traded in the market to estimate fair value. See Fair Value Measurements in Note 10. Due to tax limitations, the amounts held in the postretirement benefits portfolio have not yet been transferred to the Voluntary Employee Beneficiary Association (VEBA) trusts (see Note 8). Long-term investments primarily consist of municipal bonds, money market mutual fund investments, and mutual funds. Net unrealized gains (losses) recognized during 2012 and 2011 on securities still held at the balance sheets date were \$6,250,092 and \$5,844,074, respectively.

**Special Deposits** — Special deposits consist of money market mutual funds held by trustees restricted for use in specific construction projects. The fair value of special deposits at the balance sheet date was \$57,938,752.

Money market mutual funds reflected in special deposits are carried at fair value with the related investment income reported in Other Income. The cost of securities sold is based on the specific identification method. The fair value of money market mutual funds is determined by reference to currently available market prices and, as such, is considered Level 1. There were no unrealized gains or losses recognized on this portfolio during 2012.

Fair Value Measurements of Assets and Liabilities — The accounting guidance for Fair Value Measurements and Disclosures establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). Where observable inputs are available, pricing may be completed using comparable securities, dealer values and general market conditions to determine fair value. Valuation models utilize various inputs that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets and other observable inputs for the asset or liability.

Unamortized Debt Expense — Unamortized debt expense relates to loan origination costs incurred to secure financing. These costs are being amortized using the effective yield method over the life of the related loans.

Asset Retirement Obligations and Asset Retirement Costs — The Companies recognize the fair value of legal obligations associated with the retirement or removal of long-lived assets at the time the obligations are incurred and can be reasonably estimated. The initial recognition of this liability is accompanied by a corresponding increase in depreciable electric plant. Subsequent to the initial recognition, the liability is adjusted for any revisions to the expected value of the retirement obligation (with corresponding adjustments to electric plant) and for accretion of the liability due to the passage of time.

## OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2012 AND 2011

These asset retirement obligations are primarily related to obligations associated with future asbestos abatement at certain generating stations and certain plant closure costs.

Balance — January 1, 2011	\$ 30,999,653
Accretion Liabilities settled Revision in cash flow estimates	2,130,471 (338,375) (12,982,433)
Balance — December 31, 2011	19,809,316
Accretion Liabilities settled Revision in cash flow estimates	1,429,394 (277,331)
Balance — December 31, 2012	\$ 20,961,379

The revised estimated costs are recorded in the accompanying balance sheets. The asset retirement obligations originally assumed a decommissioning and demolition date consistent with the ICPA expiring in 2026. As the ICPA was extended an additional 14 years to 2040, the cash flow estimates were revised to reflect the new decommissioning and demolition date, which resulted in a decreased obligation as of December 31, 2011.

The Companies do not recognize liabilities for asset retirement obligations for which the fair value cannot be reasonably estimated. The Companies have asset retirement obligations associated with transmission assets at certain generating stations. However, the retirement date for these assets cannot be determined; therefore, the fair value of the associated liability currently cannot be estimated and no amounts are recognized in the consolidated financial statements herein.

**Income Taxes** — The Companies use the liability method of accounting for income taxes. Under the liability method, the Companies provide deferred income taxes for all temporary differences between the book and tax basis of assets and liabilities which will result in a future tax consequence. The Companies account for uncertain tax positions in accordance with the accounting guidance for Income Taxes.

**Use of Estimates** — The preparation of consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Subsequent Events — In preparing the accompanying financial statements and disclosures, the Companies reviewed subsequent events through April 10, 2013, which is the date the consolidated financial statements were issued.

# OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

### NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2012 AND 2011

#### 2. RELATED-PARTY TRANSACTIONS

Transactions with the Sponsoring Companies during 2012 and 2011 included the sale of all generated power to them, the purchase of Arranged Power from them and other utility systems in order to meet the Department of Energy's power requirements, contract barging services, railcar services, and minor transactions for services and materials. The Companies have Power Agreements with Louisville Gas and Electric Company, Duke Energy Ohio, Inc., The Dayton Power and Light Company, Kentucky Utilities Company, Ohio Edison Company, and American Electric Power Service Corporation as agent for the American Electric Company, Duke Energy Ohio, Inc., The Dayton Power and Light Company, The Toledo Edison Company, Ohio Edison Company, Kentucky Utilities Company, and American Electric Power Service Corporation as agent for the American Electric Power System Companies.

At December 31, 2012 and 2011, balances due from the Sponsoring Companies are as follows:

	2012	2011
Accounts receivable	\$34,343,741	\$36,650,231

American Electric Power Company, Inc. and subsidiary company owned 43.47% of the common stock of OVEC as of December 31, 2012. The following is a summary of the principal services received from the American Electric Power Service Corporation as authorized by the Companies' Boards of Directors:

	2012	2011
General services Specific projects	\$ 3,216,482 12,746,357	\$ 3,656,595 9,612,272
Total	\$15,962,839	\$13,268,867

General services consist of regular recurring operation and maintenance services. Specific projects primarily represent nonrecurring plant construction projects and engineering studies, which are approved by the Companies' Boards of Directors. The services are provided in accordance with the service agreement dated December 15, 1956, between the Companies and the American Electric Power Service Corporation.

#### 3. COAL SUPPLY

The Companies have coal supply agreements with certain nonaffiliated companies that expire at various dates from the year 2013 through 2017. Pricing for coal under these contracts is subject to contract provisions and adjustments. The Companies currently have 94% of their 2013 coal requirements under long-term agreements of one year or greater. These contracts are based on rates in effect at the time of purchase. During 2012, OVEC failed to meet the contracted obligations relating to one coal transportation contract, which resulted in liquidated damages of \$2,227,781. These costs are payable to vendors and recoverable from the Sponsor Companies within the next 12 months and are recorded as current regulatory assets (see Note 1).

# OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

### NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2012 AND 2011

#### 4. ELECTRIC PLANT

Electric plant at December 31, 2012 and 2011, consists of the following:

	2012	2011
Steam production plant	\$1,898,140,562	\$1,695,243,965
Transmission plant	74,777,994	74,443,405
General plant	12,699,998	12,523,004
Intangible	26,564	26,564
	1,985,645,118	1,782,236,938
Less accumulated depreciation	1,115,363,691	1,041,198,318
	870,281,427	741,038,620
Construction in progress	645,484,896	684,076,875
Total electric plant	\$1,515,766,323	\$1,425,115,495

All property additions and replacements are fully depreciated on the date the property is placed in service, unless the addition or replacement relates to a financed project. The majority of financed projects placed in service over the past 5 years have been recorded to steam production plant with depreciable lives ranging from 32 to 45 years. However, as the Companies' policy is to bill in accordance with the principal billings of the debt agreements, all financed projects are being depreciated in line with principal payments on outstanding debt.

#### 5. BORROWING ARRANGEMENTS AND NOTES

OVEC has an unsecured bank revolving line of credit agreement with a borrowing limit of \$275 million as of December 31, 2012, and \$225 million as of December 31, 2011. The \$225 million line of credit was renewed in June 2010, increased to \$275 million in April 2012, and has an expiration date of June 18, 2015. At December 31, 2012 and 2011, OVEC had borrowed \$60 million and \$100 million, respectively, under this line of credit. Interest expense related to line of credit borrowings was \$3,139,158 in 2012 and \$2,216,871 in 2011. During 2012 and 2011, OVEC incurred annual commitment fees of \$412,458 and \$573,958, respectively, based on the borrowing limits of the line of credit.

# OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

#### NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2012 AND 2011

#### 6. LONG-TERM DEBT

The following amounts were outstanding at December 31, 2012 and 2011:

	Interest Rate	2012	2011
Senior 2006 Notes:			
2006A due February 15, 2026	5.80 %	\$ 292,095,074	\$ 306,042,656
2006B due June 15, 2040	6.40	61,252,481	62,035,673
Senior 2007 Notes:		,,	02,032,073
2007A-A due February 15, 2026	5.90	132,475,263	138,983,105
2007A-B due February 15, 2026	5.90	33,362,594	35,001,279
2007A-C due February 15, 2026	5.90	33,628,247	35,279,980
2007B-A due June 15, 2040	6.50	30,609,314	31,003,872
2007B-B due June 15, 2040	6.50	7,708,654	7,808,021
2007B-C due June 15, 2040	6.50	7,770,034	7,870,192
Senior 2008 Notes:		, ,	.,
2008A due February 15, 2026	5.92	41,334,943	43,362,126
2008B due February 15, 2026	6.71	83,014,206	86,898,218
2008C due February 15, 2026	6.71	84,578,521	88,408,080
2008D due June 15, 2040	6.91	44,242,121	44,765,728
2008E due June 15, 2040	6.91	45,010,851	45,543,556
Series 2009 Notes:		, ,	- , , +
2009A due February 15, 2013	1.96	100,000,000	100,000,000
Series 2009 Bonds:		• •	,,
2009A due February 1, 2026	0.11	25,000,000	25,000,000
2009B due February 1, 2026	0.11	25,000,000	25,000,000
2009C due February 1, 2026	0.12	25,000,000	25,000,000
2009D due February 1, 2026	0.12	25,000,000	25,000,000
2009E due October 1, 2019	5.63	100,000,000	100,000,000
Series 2010 Bonds:			, , ,
2010A due June 29, 2014	1.48	50,000,000	50,000,000
2010B due June 29, 2016	1.48	50,000,000	50,000,000
Series 2012 Bonds:			, , , , , ,
2012A due June 1, 2032	4.95	77,091,234	_
2012A due June 1, 2039	5.05	122,312,703	-
2012B due June 1, 2040	0.12	50,000,000	_
2012C due June 1, 2040	0.11	50,000,000	<del></del> _
Total debt		1,596,486,240	1,333,002,486
Current portion of long-term debt		238,138,903	135,797,658
Total long-term debt		\$ 1,358,347,337	\$ 1,197,204,828

All of the OVEC amortizing unsecured senior notes have maturities scheduled for February 15, 2026, or June 15, 2040, as noted in the previous table.

### OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

### NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2012 AND 2011

During 2009, OVEC issued \$100 million variable rate non-amortizing unsecured senior notes (2009A Notes) in private placement, a series of four \$25 million variable rate non-amortizing tax exempt pollution control bonds (2009A, B, C, and D Bonds), and \$100 million fixed rate non-amortizing tax exempt pollution control bonds (2009E Bonds). The variable rates listed above reflect the interest rate in effect at December 31, 2012.

The 2009 Series A, B, C, and D Bonds are secured by irrevocable transferable direct-pay letters of credit, expiring August 12, 2013, and August 21, 2013, issued for the benefit of the owners of the bonds. The interest rate on the bonds are adjusted weekly, and bondholders may require repurchase of the bonds at the time of such interest rate adjustments. OVEC has entered into an agreement to provide for the remarketing of the bonds if such repurchase is required. The 2009A, B, C, and D Series Bonds are current, as they are callable at any time.

In December 2010, OVEC established a borrowing facility under which OVEC borrowed, in 2011, \$100 million variable rate bonds due February 1, 2040. In June 2011, the \$100 million variable rate bonds were issued as two \$50 million non-amortizing pollution control revenue bonds (Series 2010A and 2010B) in a short-term bank arrangement for three years and five years, respectively.

During 2012, OVEC issued \$200 million fixed rate tax-exempt midwestern disaster relief revenue bonds (2012A Bonds) and two series of \$50 million variable rate tax-exempt midwestern disaster relief revenue bonds (2012B and 2012C Bonds). The 2012A, 2012B, and 2012C Bonds will begin amortizing June 1, 2027, to their respective maturity dates. The variable rates listed above reflect the interest rate in effect at December 31, 2012.

The 2012B and 2012C Bonds are secured by irrevocable transferable direct-pay letters of credit, expiring June 28, 2014, and June 28, 2015, issued for the benefit of the owners of the bonds. The interest rates on the bonds are adjusted weekly, and bondholders may require repurchase of the bonds at the time of such interest rate adjustments. OVEC has entered into agreements to provide for the remarketing of the bonds if such repurchase is required. The 2012B and 2012C Bonds are current, as they are callable at any time.

In 2013, the \$100 million 2009A Notes were retired on February 15, 2013, with funding from the issuance of \$100 million 2013A variable rate non-amortizing unsecured senior notes (2013A Notes). The 2013A Notes mature on February 15, 2018. As a result, the 2009A Notes are excluded from current liabilities and classified as long term at December 31, 2012.

The annual maturities of long-term debt as of December 31, 2012, are as follows:

2013	\$ 38,138,903
2014	90,496,382
2015	43,000,194
2016	95,559,472
2017	48,483,907
2018–2040	1,280,807,382
Total	\$1,596,486,240

# OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

### NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2012 AND 2011

#### 7. INCOME TAXES

OVEC and IKEC file a consolidated federal income tax return. The effective tax rate varied from the statutory federal income tax rate due to differences between the book and tax treatment of various transactions as follows:

	2012	2011
Income tax expense at 35% statutory rate State income taxes — net of federal benefit	\$1,102,283 549	\$1,232,599
Temporary differences flowed through to customer bills Permanent differences and other	(224,609) 15,310	(181,531) (228,753) 29,293
Income tax provision	\$ 893,533	\$ 851,608
Effective tax rate	28.4 %	24.2 %
Components of the income tax provision were as follows:		
	2012	2011
Current income tax (benefit)/expense Deferred income tax expense/(benefit)	\$ (9,609,247) 10,502,780	\$ 5,004,517 (4,152,909)
Total income tax provision	\$ 893,533	\$ 851,608

OVEC and IKEC record deferred tax assets and liabilities based on differences between book and tax basis of assets and liabilities measured using the enacted tax rates and laws that will be in effect when the differences are expected to reverse. Deferred tax assets and liabilities are adjusted for changes in tax rates. The deferred tax assets recorded in the accompanying consolidated balance sheets consist primarily of the net deferred taxes on depreciation, postretirement benefits obligation, asset retirement obligations, regulatory assets, and regulatory liabilities.

To the extent that the Companies have not reflected credits in customer billings for deferred tax assets, they have recorded a regulatory liability representing income taxes refundable to customers under the applicable agreements among the parties. The regulatory liability was \$38,645,647 and \$40,284,930 at December 31, 2012 and 2011, respectively.

# OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

### NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2012 AND 2011

Deferred income tax assets (liabilities) at December 31, 2012 and 2011, consisted of the following:

	2012	2011
Deferred tax assets:		
Deferred revenue — advances for construction	\$ 6,789,730	\$ 10,967,289
AMT credit carryforwards	2,574,572	2,574,572
Federal net operating loss	9,392,878	-
Postretirement benefit obligation	28,748,763	27,328,379
Pension liability	9,207,805	16,511,400
Postemployment benefit obligation	875,010	851,254
Asset retirement obligations	7,340,209	6,989,207
Miscellaneous accruals	2,742,592	2,833,433
Regulatory liability — investment tax credits	1,188,204	1,197,184
Regulatory liability — net antitrust settlement	638,700	643,527
Regulatory liability — asset retirement costs	4,983,191	3,743,665
Regulatory liability — income taxes refundable		
to customers	13,844,317	14,613,570
Total deferred tax assets	88,325,971	88,253,480
Deferred tax liabilities:		
Prepaid expenses	(622,408)	(587,327)
Electric plant	(29,477,415)	(19,226,351)
Unrealized gain/loss on marketable securities	(5,616,658)	(3,453,921)
Regulatory asset — postretirement benefits	(463,906)	(1,051,631)
Regulatory asset — pension benefits	(10,701,897)	(17,966,797)
Regulatory asset — unrecognized postemployment benefits	(875,010)	(851,254)
Total deferred tax liabilities	(47,757,294)	(43,137,281)
Deferred income tax assets	\$ 40,568,677	\$ 45,116,199
Current deferred income taxes Non-current deferred income taxes	\$ 18,302,793 22,265,884	\$ 13,213,395 31,902,804

The accounting guidance for Income Taxes addresses the determination of whether the tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under this guidance, the Companies may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. The Companies have not identified any uncertain tax positions as of December 31, 2012 and 2011, and accordingly, no liabilities for uncertain tax positions have been recognized.

# OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

#### NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2012 AND 2011

On March 23, 2010, President Obama signed into law the Patient Protection and Affordable Care Act (the PPAC Act). The PPAC Act is a comprehensive health care reform bill that includes revenue-raising provisions of nearly \$400 billion over 10 years through tax increases on high-income individuals, excise taxes on high-cost group health plans, and new fees on selected health-care-related industries. In addition, on March 30, 2010, President Obama signed into law the reconciliation measure, which modifies certain provisions of the PPAC Act.

An employer offering retiree prescription drug coverage that is at least as valuable as Medicare Part D coverage is currently entitled to a federal retiree drug subsidy. Employers can currently claim a deduction for the entire cost of providing the prescription drug coverage even though a portion of the cost is offset by the subsidy they receive. However, the PPAC Act repealed the current rule permitting a deduction of the portion of the drug coverage expense that is offset by the Medicare Part D subsidy. This provision of the PPAC Act as modified by the reconciliation measure is effective for taxable years beginning after December 31, 2012.

During 2012, the passage of the PPAC Act resulted in a reduction of the postemployment benefits deferred tax asset of approximately \$80,000 and a reduction to the related regulatory liability (income taxes refundable to customers) of approximately \$80,000.

The Companies file income tax returns with the Internal Revenue Service and the states of Ohio, Indiana, and the Commonwealth of Kentucky. The Companies are no longer subject to federal tax examinations for tax years 2007 and earlier. The Companies are currently under audit by the Internal Revenue Service for the tax years ended December 31, 2008 through December 31, 2011. The Companies are no longer subject to State of Indiana tax examinations for tax years 2007 and earlier. The Companies are no longer subject to Ohio and the Commonwealth of Kentucky examinations for tax years 2006 and earlier.

#### 8. PENSION PLAN, OTHER POSTRETIREMENT AND POSTEMPLOYMENT BENEFITS

The Companies have a noncontributory qualified defined benefit pension plan (the Pension Plan) covering substantially all of their employees. The benefits are based on years of service and each employee's highest consecutive 36-month compensation period. Employees are vested in the Pension Plan after five years of service with the Companies.

Funding for the Pension Plan is based on actuarially determined contributions, the maximum of which is generally the amount deductible for income tax purposes and the minimum being that required by the Employee Retirement Income Security Act of 1974 (ERISA), as amended. The full cost of the pension benefits and related obligations has been allocated to OVEC and IKEC in the accompanying consolidated financial statements. The allocated amounts represent approximately a 57% and 43% split between OVEC and IKEC, respectively, as of December 31, 2012, and approximately a 56% and 44% split for OVEC and IKEC, respectively, as of December 31, 2011. The Pension Plan's assets as of December 31, 2012 consist of investments in equity and debt securities.

In addition to the Pension Plan, the Companies provide certain health care and life insurance benefits (Other Postretirement Benefits) for retired employees. Substantially all of the Companies' employees become eligible for these benefits if they reach retirement age while working for the Companies. These and similar benefits for active employees are provided through employer funding and insurance policies.

### OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

### NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2012 AND 2011

In December 2004, the Companies established Voluntary Employee Beneficiary Association (VEBA) trusts. In January 2011, the Companies established an IRC Section 401(h) account under the Pension Plan.

All of the trust funds' investments for the pension and postemployment benefit plans are diversified and managed in compliance with all laws and regulations. Management regularly reviews the actual asset allocation and periodically rebalances the investments to targeted allocation when appropriate. The investments are reported at fair value under the Fair Value Measurements and Disclosures accounting guidance.

All benefit plan assets are invested in accordance with each plan's investment policy. The investment policy outlines the investment objectives, strategies, and target asset allocations by plan. Benefit plan assets are reviewed on a formal basis each quarter by the OVEC/IKEC Qualified Plan Trust Committee.

The investment philosophies for the benefit plans support the allocation of assets to minimize risks and optimize net returns.

Investment strategies include:

- Maintaining a long-term investment horizon.
- Diversifying assets to help control volatility of returns at acceptable levels.
- Managing fees, transaction costs, and tax liabilities to maximize investment earnings.
- Using active management of investments where appropriate risk/return opportunities exist.
- Keeping portfolio structure style neutral to limit volatility compared to applicable benchmarks.

The target asset allocation for each portfolio is as follows:

Pension Plan Assets	Target
Domestic equity International and global equity Fixed income	15.0 % 15.0 70.0
VEBA Plan Assets	Target
Domestic equity International and global equity Fixed income Cash	20.0 % 20.0 57.0 3.0

Each benefit plan contains various investment limitations. These limitations are described in the investment policy statement and detailed in customized investment guidelines or documented by mutual fund prospectus. These investment guidelines require appropriate portfolio diversification and define security concentration limits. Each investment manager's portfolio is compared to an appropriate diversified benchmark index.

# OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

#### NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2012 AND 2011

#### Equity investment limitations:

- No security in excess of 5% of all equities.
- Cash equivalents must be less than 10% of each investment manager's equity portfolio.
- Individual securities must be less than 15% of each manager's equity portfolio.
- No investment in excess of 5% of an outstanding class of any company.
- No securities may be bought or sold on margin or other use of leverage.
- As otherwise defined by fund prospectus.

**Fixed Income Limitations** — As of December 31, 2012, the Pension Plan fixed income allocation consists of managed accounts composed of U.S. Government, corporate, and municipal obligations. The VEBA benefit plans' fixed income allocation is composed of a variety of fixed income managed accounts and mutual funds. Investment limitations for these fixed income funds are defined by manager prospectus.

Cash Limitations — Cash and cash equivalents are held in each trust to provide liquidity and meet short-term cash needs. Cash equivalent funds are used to provide diversification and preserve principal. The underlying holdings in the cash funds are investment grade money market instruments, including money market mutual funds, certificates of deposit, treasury bills, and other types of investment-grade short-term debt securities. The cash funds are valued each business day and provide daily liquidity. Projected Pension Plan and Other Postretirement Benefits obligations and funded status as of December 31, 2012 and 2011, are as follows:

# OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

### NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2012 AND 2011

•	Pensi	on Plan	Other Postretirement Benefits			
	2012	2011	2012	2011		
Change in projected benefit obligation:						
Projected benefit obligation — beginning						
of year	\$192,294,158	\$150,799,587	\$171,866,123	\$ 123,680,352		
Service cost	7,050,298	5,235,212	6,411,493	4,318,132		
Interest cost	8,383,604	7,862,149	7,442,065	6,727,007		
Plan participants' contributions	_	- -	908,758	846,824		
Benefits paid	(3,536,952)	(3,142,434)	(4,449,852)	(4,937,587)		
Net actuarial (gain)/loss	(9,114,566)	31,589,560	7,821,460	40,723,781		
Medicare subsidy	_	<u>-</u>	323,844	507,614		
Expenses paid from assets	(69,383)	(49,916)	<u>-</u>	<del></del>		
Projected benefit obligation — end						
of year	195,007,159	192,294,158	190,323,891	171,866,123		
Change in fair value of plan assets:						
Fair value of plan assets — beginning						
of year	141,371,363	127,044,744	94,948,011	92,356,147		
Actual return on plan assets	21,180,806	11,418,969	10,538,257	288,095		
Expenses paid from assets	(69,383)	(49,916)	-	-		
Employer contributions	5,500,000	6,100,000	5,957,250	5,891,110		
Plan participants' contributions	-	-	908,758	846,824		
Medicare subsidy	-	-	323,844	503,422		
Benefits paid	(3,536,952)	(3,142,434)	(4,449,852)	(4,937,587)		
Fair value of plan assets — end						
of year	164,445,834	141,371,363	108,226,268	94,948,011		
(Underfunded) status — end of year	\$ (30,561,325)	\$ (50,922,795)	\$ (82,097,623)	\$ (76,918,112)		

See Note 1 for information regarding regulatory assets related to the Pension Plan and Other Postretirement Benefits plan.

On December 8, 2003, the President of the United States of America signed into law the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act). The Act introduced a prescription drug benefit to retirees as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a prescription drug benefit that is actuarially equivalent to the benefit provided by Medicare. The Companies believe that the coverage for prescription drugs is at least actuarially equivalent to the benefits provided by Medicare for most current retirees because the benefits for that group substantially exceed the benefits provided by Medicare, thereby allowing the Companies to qualify for the subsidy. The Companies' employer contributions for Other Postretirement Benefits in the above table are net of subsidies received of \$323,844 and \$503,422 for 2012 and 2011, respectively. The Companies have accounted for the subsidy as a reduction of the benefit obligation detailed in the above table. The benefit obligation was reduced by approximately \$0 and \$500,000 as of December 31, 2012 and 2011, respectively. See Note 7 for changes in the tax law surrounding the new health care bill.

# OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

#### NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2012 AND 2011

The accumulated benefit obligation for the Pension Plan was \$167,595,378 and \$154,437,821 at December 31, 2012 and 2011, respectively.

Components of Net Periodic Benefit Cost — The Companies record the expected cost of Other Postretirement Benefits over the service period during which such benefits are earned.

Pension expense is recognized as amounts are contributed to the Pension Plan and billed to customers. The accumulated difference between recorded pension expense and the yearly net periodic pension expense, as calculated under the accounting guidance for Compensation — Retirement Benefits, is billable as a cost of operations under the ICPA when contributed to the pension fund. This accumulated difference has been recorded as a regulatory asset in the accompanying consolidated balance sheets

	Pension Plan			stretirement nefits
	2012	2011	2012	2011
Service cost Interest cost	\$ 7,050,298 8,383,604	\$ 5,235,212 7,862,149	\$ 6,411,493	\$ 4,318,132
Expected return on plan assets Amortization of prior service cost	(8,522,609) 189,437	(7,693,957) 189,437	7,442,065 (5,516,937)	6,727,007 (5,282,524)
Recognized actuarial loss	2,086,365	109,437	(379,000) 1,577,730	(379,000) (133,988)
Total benefit cost	9,187,095	5,592,841	9,535,351	5,249,627
Pension and other postretirement benefits expense recognized in the consolidated statements of income and retained earnings and				
billed to Sponsoring Companies under the ICPA	\$ 5,500,000	\$ 6,100,000	\$ 5,500,000	\$ 4,908,485

# OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

### NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2012 AND 2011

The following table presents the classification of Pension Plan assets within the fair value hierarchy at December 31, 2012 and 2011:

	Fair Value Measurements at Reporting Date Using				
2012	Quoted Prices in Active Market for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)		
Domestic equity International and global equity Cash and cash equivalents U.S. Treasury securities Corporate securities Municipal securities Total fair value	\$23,558,247 17,292,251 4,924,712 - - - - \$45,775,210	\$ - 8,550,837 - 6,804,928 92,091,492 11,223,367 \$118,670,624	\$ - - - - - - - - - - -		
2011  Domestic equity International and global equity Cash and cash equivalents	\$21,716,581 14,047,289 5,302,174	\$ - 6,902,062	\$ - -		
U.S. Treasury securities  Total fair value	\$41,066,044	93,403,257 \$100,305,319	<u> </u>		

# OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

### NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2012 AND 2011

The following table presents the classification of VEBA and 401(h) account assets within the fair value hierarchy at December 31, 2012 and 2011:

Fair Value Measurements at Reporting Date Using **Quoted Prices** Significant in Active Other **Significant** Market for Observable Unobservable **Identical Assets** Inputs Inputs 2012 (Level 1) (Level 2) (Level 3) Domestic equity \$21,360,870 International and global equity 22,601,305 Fixed income mutual funds 48,177,536 Fixed income securities 13,581,890 Cash and cash equivalents 2,504,667 Total fair value \$94,644,378 \$13,581,890 \$ 2011 Domestic equity \$19,752,467 \$ International and global equity 31,865,804 Fixed income mutual funds 37,880,252 Cash and cash equivalents 5,449,488 Total fair value \$94,948,011

Pension Plan and Other Postretirement Benefit Assumptions — Actuarial assumptions used to determine benefit obligations at December 31, 2012 and 2011, were as follows:

	Pension	Plan		Benefits		
	2012	2011	2012		201	1
			Medical	Life	Medical	Life
Discount rate Rate of compensation increase	4.29 % 3.00	4.40 % 4.00	4.40 % N/A	4.30 % 3.00	4.40 % N/A	4.40 % 4.00

# OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

### NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2012 AND 2011

Actuarial assumptions used to determine net periodic benefit cost for the years ended December 31, 2012 and 2011, were as follows:

	Pension	Plan	Othe	r Postretire	ement Benef	its
	2012	2011	201	2	201	1
			Medical	Life	Medical	Life
Discount rate	4.40 %	5.50 %	4.40 %	4.40 %	5.50 %	5.50 %
Expected long-term return on						
plan assets	6.00	6.00	5.60	6.50	5.60	5.60
Rate of compensation increase	4.00	4.00	N/A 4.00		N/A	4.00

In selecting the expected long-term rate of return on assets, the Companies considered the average rate of earnings expected on the funds invested or to be invested to provide for plan benefits. This included considering the Pension Plan and VEBA trusts' asset allocation, as well as the target asset allocations for the future, and the expected returns likely to be earned over the life of the Pension Plan and the VEBAs.

Assumed health care cost trend rates at December 31, 2012 and 2011, were as follows.

	2012	2011
Health care trend rate assumed for next year — participants under 65	8.00 %	8.50 %
Health care trend rate assumed for next year — participants over 65	8.00	8.50
Rate to which the cost trend rate is assumed to decline (the ultimate		
trend rate) — participants under 65	5.00	5.00
Rate to which the cost trend rate is assumed to decline (the ultimate		
trend rate) — participants over 65	5.00	5.00
Year that the rate reaches the ultimate trend rate	2019	2019

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	One-Percentage Point Increase	One-Percentage Point Decrease
Effect on total service and interest cost Effect on postretirement benefit obligation	\$ 3,134,278 36,349,761	\$ (2,355,685) (28,085,825)

**Pension Plan and Other Postretirement Benefit Assets** — The asset allocation for the Pension Plan and VEBA trusts at December 31, 2012 and 2011, by asset category was as follows:

	Pension	n Plan	VEBA T	rusts	
	2012	2011	2012	2011	
Asset category:					
Equity securities	30 %	30 %	41 %	41 %	
Debt securities	70	70	59	59	

# OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

# NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2012 AND 2011

**Pension Plan and Other Postretirement Benefit Contributions**— The Companies expect to contribute \$6,400,000 to their Pension Plan and \$7,661,448 to their Other Postretirement Benefits plan in 2013.

Estimated Future Benefit Payments — The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

Years Ending December 31	Pension Plan	Other Postretirement Benefits
2013	\$ 4,175,740	\$ 5,651,448
2014	4,804,038	5,992,604
2015	5,537,299	6,385,523
2016	6,393,997	6,983,700
2017	7,237,682	7,567,996
Five years thereafter	50,302,520	45,794,286

Postemployment Benefits — The Companies follow the accounting guidance in Compensation — Non-Retirement Postemployment Benefits and accrue the estimated cost of benefits provided to former or inactive employees after employment but before retirement. Such benefits include, but are not limited to, salary continuations, supplemental unemployment, severance, disability (including workers' compensation), job training, counseling, and continuation of benefits, such as health care and life insurance coverage. The cost of such benefits and related obligations has been allocated to OVEC and IKEC in the accompanying consolidated financial statements. The allocated amounts represent approximately a 45% and 55% split between OVEC and IKEC, respectively, as of December 31, 2012, and approximately a 46% and 54% split between OVEC and IKEC, respectively, as of December 31, 2011. The liability is offset with a corresponding regulatory asset and represents unrecognized postemployment benefits billable in the future to customers. The accrued cost of such benefits was \$2,498,759 and \$2,412,685 at December 31, 2012 and 2011, respectively.

**Defined Contribution Plan** — The Companies have a trustee-defined contribution supplemental pension and savings plan that includes 401(k) features and is available to employees who have met eligibility requirements. The Companies' contributions to the savings plan equal 100% of the first 1% and 50% of the next 5% of employee-participants' contributions. Benefits to participating employees are based solely upon amounts contributed to the participants' accounts and investment earnings. By its nature, the plan is fully funded at all times. The employer contributions for 2012 and 2011 were \$1,942,045 and \$1,804,270, respectively.

#### 9. ENVIRONMENTAL MATTERS

Title IV of the 1990 Clean Air Act Amendments (CAAAs) required the Companies to reduce sulfur dioxide (SO<sub>2</sub>) emissions in two phases: Phase I in 1995 and Phase II in 2000. The Companies selected a fuel switching strategy to comply with the emission reduction requirements. The Companies also purchased additional SO<sub>2</sub> allowances. The cost of these purchased allowances has been inventoried and

### OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

### NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2012 AND 2011

included on an average cost basis in the cost of fuel consumed when used. The cost of unused allowances at December 31, 2012 and 2011, was \$86,649 and \$28,519, respectively.

Title IV of the 1990 CAAAs also required the Companies to comply with a nitrogen oxides ( $NO_x$ ) emission rate limit of 0.84 lb/mmBtu in 2000. The Companies installed overfire air systems on all eleven units at the plants to comply with this limit. The total capital cost of the eleven overfire air systems was approximately \$8.2 million.

During 2002 and 2003, Ohio and Indiana finalized respective  $NO_x$  State Implementation Plan (SIP) Call regulations that required further significant  $NO_x$  emission reductions for coal-burning power plants during the ozone control period. The Companies installed selective catalytic reduction (SCR) systems on ten of their eleven units to comply with these rules. The total capital cost of the ten SCR systems was approximately \$355 million.

On March 10, 2005, the United States Environmental Protection Agency (the U.S. EPA) issued the Clean Air Interstate Rule (CAIR) that required further significant reductions of SO<sub>2</sub> and NO<sub>x</sub> emissions from coal-burning power plants. On March 15, 2005, the U.S. EPA also issued the Clean Air Mercury Rule (CAMR) that required significant mercury emission reductions for coal-burning power plants. These emission reductions were required in two phases: 2009 and 2015 for NO<sub>x</sub>; 2010 and 2015 for SO<sub>2</sub>; and 2010 and 2018 for mercury. Ohio and Indiana subsequently finalized their respective versions of CAIR and CAMR. In response, the Companies determined that it would be necessary to install flue gas desulfurization (FGD) systems at both plants to comply with these new rules. Following completion of the necessary engineering and permitting, construction was started on the new FGD systems.

In February 2008, the D.C. Circuit Court of Appeals issued a decision which vacated the federal CAMR and remanded the rule to the U.S. EPA with a determination that the rule be rewritten under the maximum achievable control technologies (MACT) provision of Section 112(d) of the Clean Air Act. A group of electric utilities and the U.S. EPA requested a rehearing of the decision, which was denied by the Court. Following those denials, both the group of electric utilities and the U.S. EPA requested that the U.S. Supreme Court hear the case. However, in February 2009, the U.S. EPA withdrew its request and the group of utilities' request was denied. These actions left the original court decision in place, which vacated the federal CAMR and remanded the rule to the U.S. EPA with a determination that the rule be rewritten under the MACT provision of Section 112(d) of the Clean Air Act. The U.S. EPA has subsequently written a replacement rule for the regulation of coal-fired utility emissions of mercury and other hazardous air pollutants. This replacement rule was published in the Federal Register on February 16, 2012, and it is referred to as the Mercury and Air Toxics Standards (or MATS) rule. The rule became final on April 16, 2012, and OVEC-IKEC must be in compliance by April 15, 2015 (absent qualifying for and securing a one-year extension from the state regulatory agencies).

In July 2008, the D.C. Circuit Court of Appeals issued a decision that vacated the federal CAIR and remanded the rule to the U.S. EPA. In September 2008, the U.S. EPA, a group of electric utilities and other parties filed petitions for rehearing. In December 2008, the D.C. Circuit Court of Appeals granted the U.S. EPA's petition and remanded the rule to the U.S. EPA without vacatur, allowing the federal CAIR to remain in effect while a new rule was developed and promulgated. Following the remand, the U.S. EPA promulgated a replacement rule to CAIR. This new rule is called the Cross-State Air Pollution Rule (CSAPR) and it was issued on July 6, 2011, and it was scheduled to go into effect on January 1,

# OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

### NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2012 AND 2011

2012. However, on December 30, 2011, the D.C. Circuit Court issued an indefinite "stay" of the CSAPR rule until the Court considers the numerous state, trade association, and industry petitions filed to have the rule either stayed or reviewed. The Court also instructed the U.S. EPA to keep CAIR in place while they consider the numerous petitions. On August 21, 2012, in a 2-1 decision, the D.C. Circuit Court vacated the CSAPR rule and ordered the U.S. EPA to keep CAIR in effect until a CSAPR replacement rule is promulgated. The U.S. EPA and other parties filed a petition seeking rehearing before the entire D.C. Circuit Court on October 5, 2012, and on January 24, 2013, the Court denied all petitions for rehearing. The U.S. EPA and other parties may now petition the U.S. Supreme Court to review the D.C. Circuit Court's decision on CSAPR. In the interim, CAIR will remain in effect.

In December 2008, the Boards of Directors of the Companies authorized a delay in construction of the FGD at the Clifty Creek plant of at least 18 months due to economic uncertainty in the capital markets.

In March 2009, the Boards of Directors also authorized a delay in the tie-in of the FGD systems of all five generating units at the Kyger Creek plant pending an investigation into the structural integrity of the internal components of two newly constructed jet bubbling reactors (JBRs), which are major components of the FGD system. Extensive studies were conducted relating to this design issue, which affected the FGD construction projects at both the Kyger Creek and Clifty Creek plants, and as a result, the Boards of Directors authorized a complete redesign and replacement of the JBR internal components to resolve this structural integrity issue.

In December 2010, the Boards of Directors authorized the completion of the FGD construction projects at the Kyger Creek and Clifty Creek plants with the redesign and replacement of the JBR internal components. The Kyger Creek plant FGD system became fully operational during the second quarter of 2012 and the Clifty Creek plant FGD system is expected to be fully operational by the end of the second quarter of 2013. One of the two FGD systems at Kyger Creek began successful operations in November 2011. The second FGD at Kyger Creek began operating in the first quarter of 2012.

Additional  $SO_2$  and  $NO_x$  allowances were purchased to operate the Clifty Creek generating units to comply with the reinstated CAIR environmental emission rules during the 2012 compliance period. With the Kyger Creek FGD system now fully operational and with the Clifty Creek FGD systems scheduled to become operational in 2013, and with the 10 SCR systems operational at both plants, management does not currently anticipate the need to purchase additional  $SO_2$  allowances in 2013; however, there may be a need to purchase limited  $NO_x$  allowances in 2013 and beyond.

Clifty Creek's two FGD scrubbers are scheduled to come online in March and May of 2013. As a result, OVEC is positioned to meet the anticipated reductions in  $SO_2$  and  $NO_x$  emissions that are required under the CSAPR rule if the U.S. EPA ultimately prevails on its petition before the Supreme Court and CSAPR is reinstated. Alternatively, OVEC is also positioned to meet comparable emissions reductions that may be required by an equivalent replacement rule should the D.C. Circuit Court decision ultimately stand.

Once all FGD systems are fully operational, OVEC expects to have adequate  $SO_2$  allowances available without having to rely on market purchases if the CSAPR rules are upheld in their current form; however, additional  $NO_x$  allowances or additional  $NO_x$  controls may be necessary for Clifty Creek Unit 6.

## OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

### NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2012 AND 2011

Management expects that, with the SCRs and FGD systems fully functional, OVEC will be able to meet the emissions requirements outlined in the Mercury and Air Toxics Standards (MATS) rule by the April 15, 2015, compliance deadline.

The total cost to complete the new Kyger Creek and Clifty Creek FGD systems and the associated landfills is currently estimated not to exceed \$1.35 billion, including the amounts expended to date and included in construction in progress in the accompanying balance sheets.

On November 6, 2009, the Companies received a Section 114 Information Request from the U.S. EPA. The stated purpose of the information request was for the U.S. EPA to obtain the necessary information to determine if the Kyger Creek and Clifty Creek plants have been operating in compliance with the Federal Clean Air Act. Attorneys for the Companies subsequently contacted the U.S. EPA and established a schedule for submission of the requested information. Based on this schedule, all requested information was submitted to the U.S. EPA by March 8, 2010.

In late December 2011, OVEC-IKEC received a letter dated December 21, 2011, from the U.S. EPA requesting follow-up information. Specifically, the U.S. EPA asked for an update on the status of the FGD scrubber projects at both plants as well as additional information on any other new emissions controls that either have been installed or are planned for installation since the last submittal we filed on March 8, 2012. This information was prepared and filed with the U.S. EPA in late January 2012. In the fall of 2012, following an on-site visit, the U.S. EPA made an informal request that OVEC provide the agency with a monthly email progress report on the Clifty Creek FGD project until both FGD systems are operational in 2013. As of this date, the only communication OVEC has had with the U.S. EPA related to either the original Section 114 data submittal or the supplemental data filing made in 2011 are the monthly email progress reports.

#### 10. FAIR VALUE MEASUREMENTS

The accounting guidance for Financial Instruments requires disclosure of the fair value of certain financial instruments. The estimates of fair value under this guidance require the application of broad assumptions and estimates. Accordingly, any actual exchange of such financial instruments could occur at values significantly different from the amounts disclosed. As cash and cash equivalents, current receivables, current payables, and line of credit borrowings are all short term in nature, their carrying amounts approximate fair value.

OVEC utilizes its trustee's external pricing service in its estimate of the fair value of the underlying investments held in the benefit plan trusts and investment portfolios. The Companies' management reviews and validates the prices utilized by the trustee to determine fair value. Equities and fixed income securities are classified as Level 1 holdings if they are actively traded on exchanges. Certain fixed income securities do not trade on an exchange and do not have an official closing price. Pricing vendors calculate bond valuations using financial models and matrices. Fixed income securities are typically classified as Level 2 holdings because their valuation inputs are based on observable market data. Observable inputs used for valuing fixed income securities are benchmark yields, reported trades, broker/dealer quotes, issuer spreads, bids, offers, and economic events. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments.

### OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

#### NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2012 AND 2011

As of December 31, 2012 and 2011, the Companies held certain assets that are required to be measured at fair value on a recurring basis. These consist of investments recorded within special deposits and long-term investments. The special deposits consist of money market mutual funds restricted for use on certain projects. The investments consist of money market mutual funds, equity mutual funds, and fixed income municipal securities. Changes in the observed trading prices and liquidity of money market funds are monitored as additional support for determining fair value, and unrealized gains and losses are recorded in earnings.

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. Furthermore, while the Companies believe their valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different fair value measurement at the reporting date.

**Long-Term Investments** — Assets measured at fair value on a recurring basis at December 31, 2012 and 2011, were as follows:

Fair Value Measurements at Reporting Date Using **Quoted Prices** Significant in Active Other Significant Market for Observable Unobservable **Identical Assets** Inputs Inputs 2012 (Level 1) (Level 2) (Level 3) Equity mutual funds \$21,192,480 \$ Fixed income municipal securities 96,088,024 Cash and cash equivalents 61,009,960 Total fair value \$82,202,440 \$96,088,024 \$ 2011 Equity mutual funds \$17,515,143 Fixed income municipal securities 86,556,577 Cash and cash equivalents 2,105,486 Total fair value \$19,620,629 \$86,556,577

Long-Term Debt — The fair values of the senior notes and fixed rate bonds were estimated using discounted cash flow analyses based on current incremental borrowing rates for similar types of borrowing arrangements. These fair values are not reflected in the balance sheets.

# OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

### NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2012 AND 2011

The fair values and recorded values of the senior notes and fixed and variable rate bonds as of December 31, 2012 and 2011, are as follows:

		2	012			2	011	
		Fair Value	R	Recorded Value		Fair Value	R	ecorded Value
Senior 2006 Notes	\$	351,945,355	\$	292,095,074	\$	346,562,704	\$	306,042,656
2006 Notes Extended		80,253,001		61,252,481		71,775,275		62,035,673
Senior 2007 Notes		241,074,733		199,466,104		238,414,890		209,264,364
2007 Notes Extended		60,951,383		46,088,002		54,417,306		46,682,085
Senior 2008 Notes		262,552,244		208,927,670		259,006,749		218,668,424
2008 Notes Extended		122,856,716		89,252,972		109,748,707		90,309,284
Senior 2009A Notes		100,000,000		100,000,000		98,520,000		100,000,000
2009A Bonds		25,000,000		25,000,000		25,000,000		25,000,000
2009B Bonds		25,000,000		25,000,000		25,000,000		25,000,000
2009C Bonds		25,000,000		25,000,000		25,000,000		25,000,000
2009D Bonds		25,000,000		25,000,000		25,000,000		25,000,000
2009E Bonds		115,638,000		100,000,000		110,750,000		100,000,000
2010A&B Bonds		100,000,000		100,000,000		100,000,000		100,000,000
2012A Bonds		82,713,600		77,091,234		-		-
2012A Bonds		130,217,472		122,312,703		_		-
2012B&C Bonds	_	100,000,000	_	100,000,000	_		_	<u> </u>
Total	\$	1,848,202,504	<u>\$</u>	1,596,486,240	<u>\$ 1</u>	1,489,195,631	\$	1,333,002,486

#### 11. LEASES

OVEC has entered into operating leases to secure railcars for the transportation of coal in connection with the fuel switching modifications at the OVEC and the IKEC generating stations. OVEC has railcar lease agreements that extend to as long as December 31, 2025, with options to exit the leases under certain conditions. The amount in property under capital leases is \$2,277,088 with accumulated depreciation of \$460,693 and \$141,434 as of December 31, 2012 and 2011, respectively. OVEC also has various other operating leases with other property and equipment. During 2012, OVEC terminated certain railcar lease agreements, which resulted in lease termination costs of \$3,497,300. As of December 31, 2012, OVEC had billed Sponsor Companies \$499,614 resulting in a balance of \$2,997,686 that will be recovered from the Sponsor Companies within the next 12 months. This amount is to be recorded in current regulatory assets (see Note 1) and is not included in the lease payments below.

# OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

### NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2012 AND 2011

Future minimum lease payments for capital and operating leases at December 31, 2012, are as follows:

Years Ending December 31	Operating	Capital
2013	\$ 1,834,312	\$ 535,492
2014	1,050,918	527,119
2015	850,338	351,787
2016	4,504	139,313
2017	-	119,119
Thereafter	-	573,220
Total future minimum lease payments	\$ 3,740,072	2,246,050
Less estimated interest element		590,372
Estimated present value of future minimum lease payments		\$1,655,678

The annual operating lease cost incurred was \$3,310,227 and \$3,435,766 for 2012 and 2011, respectively, and the annual capital lease cost incurred was \$437,084 and \$138,376 for 2012 and 2011, respectively.

#### 12. COMMITMENTS AND CONTINGENCIES

The Companies are party to or may be affected by various matters under litigation. Management believes that the ultimate outcome of these matters will not have a significant adverse effect on either the Companies' future results of operation or financial position.

\* \* \* \* \* \*

# OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

#### INDEPENDENT AUDITORS' REPORT

To the Board of Directors of Ohio Valley Electric Corporation:

We have audited the accompanying consolidated financial statements of Ohio Valley Electric Corporation and its subsidiary company, Indiana-Kentucky Electric Corporation (the "Companies"), which comprise the consolidated balance sheets as of December 31, 2012 and 2011, and the related consolidated statements of income and retained earnings and cash flows for the years then ended, and the related notes to the consolidated financial statements.

#### Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

#### **Auditors' Responsibility**

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Companies' preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Companies' internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

#### Opinion

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Companies as of December 31, 2012 and 2011, and the results of their operations and their cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

DELOITTE & TOUCHE LLP

DEOME : TOUGHE LIP

April 10, 2013

# OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

#### OVEC PERFORMANCE—A 5-YEAR COMPARISON

	2012	2011	2010	2009	2008
Net Generation (MWh)	10,514,762	14,468,168	14,634,079	15,260,922	15,260,029
Energy Delivered (MWh) to:					
DOE	207,692	253,157	249,139	264,664	270,369
Sponsors	10,340,568	14,199,025	14,421,180	15,069,699	15,026,497
Maximum Scheduled (MW) by:					
DOE	36	39	39	39	45
Sponsors	2,165	2,247	2,223	2,212	2,216
Power Costs to:					
DOE	\$9,097,000	\$11,643,000	\$11,207,000	\$11,451,000	\$18,539,000
Sponsors	\$650,027,000	\$722,153,000	\$671,671,000	\$632,506,000	\$605,355,000
Average Price (MWh):					
DOE	\$43.802	\$45.993	\$44.984	\$43.266	\$68.570
Sponsors	\$62.862	\$50.859	\$46.575	\$41.972	\$40.286
Operating Revenues	\$670,819,000	\$716,938,000	\$690,687,000	\$648,593,000	\$621,813,000
Operating Expenses	\$599,891,000	\$653,696,000	\$618,790,000	\$584,881,000	\$566,798,000
Cost of Fuel Consumed	\$302,926,000	\$397,543,000	\$358,507,000	\$329,448,000	\$340,213,000
Taxes (federal, state, and local)	\$11,659,000	\$12,059,000	\$11,208,000	\$12,298,000	\$10,808,000
Payroll	\$61,907,000	\$57,141,000	\$55,609,000	\$56,589,000	\$53,694,000
Fuel Burned (tons)	5,290,009	7,310,107	7,506,530	7,900,894	7,891,440
Heat Rate (Btu per kWh, net generation)	10,581	10,467	10,310	10,299	10,236
Unit Cost of Fuel Burned (per mmBtu)	\$2.72	\$2.63	\$2.38	\$2.10	\$2.18
Equivalent Availability (percent)	78.9	83.0	81.0	81.6	80.5
Power Use Factor (percent)	69.40	89.61	92.82	96.29	96.39
Employees (year-end)	828	810	783	809	817

### OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

#### **DIRECTORS**

#### **Ohio Valley Electric Corporation**

- 1,2 ANTHONY J. AHERN, Columbus, Ohio President and Chief Executive Officer Buckeye Power Generating, LLC
- NICHOLAS K. AKINS, Columbus, Ohio President and Chief Executive Officer American Electric Power Company, Inc.
  - ERIC D. BAKER, Cadillac, Michigan
    President and Chief Executive Officer
    Wolverine Power Supply Cooperative, Inc.
  - WILLIAM S. DOTY, Evansville, Indiana Executive Vice President – Utility Operations Vectren Corporation
  - JAMES R. HANEY, Akron, Ohio Vice President, Compliance & Regulated Services and Chief FERC Compliance Officer FirstEnergy Services Company
- <sup>2</sup> LANA L. HILLEBRAND, Columbus, Ohio Senior Vice President and Chief Administrative Officer American Electric Power Company, Inc.
  - **DENNIS A. LANTZY**, Dayton, Ohio Senior Vice President Generation DPL Inc.

- <sup>1</sup> CHARLES D. LASKY, Akron, Ohio Vice President, Fossil Fleet Operations FirstEnergy Generation, LLC
- <sup>2</sup> MARK C. McCULLOUGH, Columbus, Ohio Executive Vice President - Generation American Electric Power Company, Inc.
  - STEVEN K. NELSON, Coshocton, Ohio Chairman, Buckeye Power Board of Trustees The Frontier Power Company
  - PATRICK W. O'LOUGHLIN, Columbus, Ohio Vice President and Chief Operating Officer Buckeye Power Generating, LLC
  - ROBERT P. POWERS, Columbus, Ohio Executive Vice President and Chief Operating Officer American Electric Power Company, Inc.
- <sup>2</sup> PAUL W. THOMPSON, Louisville, Kentucky Chief Operating Officer LG&E and KU Energy LLC
- JOHN N. VOYLES, Louisville, Kentucky Vice President, Transmission and Generation Services LG&E and KU Energy LLC
- CHARLES WHITLOCK, Cincinnati, Ohio President, Midwest Commercial Generation Duke Energy Corporation

#### **Indiana-Kentucky Electric Corporation**

- <sup>1</sup> ANTHONY J. AHERN, Columbus, Ohio President and Chief Executive Officer Buckeye Power Generating, LLC
- NICHOLAS K. AKINS, Columbus, Ohio President and Chief Executive Officer American Electric Power Company, Inc.
  - PAUL CHODAK, Fort Wayne, Indiana President and Chief Operating Officer Indiana Michigan Power
  - WILLIAM S. DOTY, Evansville, Indiana Executive Vice President – Utility Operations Vectren Corporation

- WAYNE D. GAMES, Evansville, Indiana Vice President – Power Supply Vectren Corporation
- <sup>1</sup> CHARLES D. LASKY, Akron, Ohio Vice President, Fossil Fleet Operations FirstEnergy Generation, LLC
- MARC E. LEWIS, Fort Wayne, Indiana Vice President – External Relations Indiana Michigan Power

#### OFFICERS-OVEC AND IKEC

NICHOLAS K. AKINS President

MARK A. PEIFER
Vice President and
Chief Operating Officer

**DAVID E. JONES**Vice President-Operations

<sup>1</sup>Member of Executive Committee. <sup>2</sup>Member of Human Resources Committee. JOHN D. BRODT Chief Financial Officer, Secretary and Treasurer

RONALD D. COOK Assistant Secretary, Assistant Treasurer and Supply Chain Director JULIE SLOAT
Assistant Secretary and
Assistant Treasurer

Exhibit KMM-4

#### OHIO POWER COMPANY'S RESPONSE

#### TO INDUSTRIAL ENERGY USERS-OHIO'S

# DISCOVERY REQUEST PUCO CASE NO. 13-2385-EL-SSO et al. SECOND SET

#### **INTERROGATORY**

INT-2-001 During the technical conference held at the Commission offices on January 8,

2014, AEP-Ohio stated that it had estimates of the impact of the proposed Power

Purchase Agreement Rider. Provide the estimates of the Power Purchase

Agreement Rider for each year of the proposed electric security plan ("ESP").

#### **RESPONSE**

See COMPETITIVELY-SENSITIVE CONFIDENTIAL IEU 2-001 Attachments 1 through 3.

Exhibit KMM-5

CONFIDENTIAL

AEP Ohio OVEC Data 2015-2018  Based on Aug market data assumptions in 2013 LRP forecast  OVEC Gapacity UCAP  OVEC Capacity (S/MVH)  Energy Revenue (S000)  OVEC Capacity & Service (S000)  OVEC Capacity (S/MVH)  Energy Revenue (S000)  OVEC Capacity & Service (S/MVH)  Energy Revenue (S000)  OVEC Cost (Bref-some var) (S/MVH)  OVEC Energy (Gov)  OVEC Capacity & Service (S/MVH)  Energy Revenue (S000)  OVEC Cost (Bref-some var) (S/MVH)  OVEC Energy (Gov)  OVEC Cost (Bref-some var) (S/MVH)  Energy Revenue (S000)  OVEC Cost (Bref-some var) (S/MVH)  Energy Revenue (S000)  OVEC Cost (Bref-some var) (S/MVH)  OVEC Cost (Bref-some var) (S/MVH)  OVEC Energy (Gov)  OVEC Revenue (Gapacity & Energy)  OVEC Cost (Bref-some var) (S/MVH)  OVEC Cost (Bref-some var) (S/MVH)  OVEC Revenue (Gapacity & Energy)  OVEC Cost (Bref-some var) (S/MVH)  OVEC Revenue (Gapacity & Energy)  OVEC Cost (Bref-some var) (S/MVH)  OVEC Cost (Bref-some var) (S/MVH)  OVEC Cost (Bref-some var) (S/MVH)  OVEC Revenue (Gapacity & Energy)  OVEC Cost (Bref-some var) (S/MVH)  OVEC Revenue (Gapacity & Energy)  OVEC Revenue (Gapacity & Gapacity & Gapacity & Gapacity & Gapacity & Gapacity & Gapacity										IEU Set 2
Jul-15   Aug-15   Sep-15   Oct-15   Nov-15   Dec-15   Jan-16   Fe     Jul-15   Aug-15   Sep-15   Oct-15   Nov-15   Dec-15   Jan-16   Fe     393   393   393   393     393   393   393     393   393   393     393   393   393     393   393   393     393   393   393     393   393   393     393   393   393     314   31   30   314   316     1,656   1,656   1,656   1,656   1,656   1,656     1,656   1,656   1,656   1,656   1,656     1,656   1,656   1,656   1,656     1,656   1,656   1,656   1,656     1,656   1,656   1,656   1,656     1,656   1,656   1,656   1,656     1,656   1,656   1,656   1,656     1,656   1,656   1,656   1,656     1,656   1,656   1,656   1,656     1,656   1,656   1,656   1,656     1,656   1,656   1,656     1,656   1,656   1,656     1,656   1,656   1,656     1,656   1,656   1,656     1,656   1,656   1,656     1,656   1,656   1,656     1,656   1,656   1,656     1,656   1,656   1,656     1,656   1,656   1,656     1,656   1,656   1,656     1,656   1,656   1,656     1,656   1,656   1,656     1,656   1,656   1,656     1,656   1,656   1,656     1,656   1,656     1,656   1,656     1,656   1,656     1,656   1,656     1,656   1,656     1,656   1,656     1,656   1,656     1,656   1,656     1,656   1,656     1,656   1,656     1,656   1,656     1,656   1,656     1,656   1,656     1,656   1,656     1,656   1,656     1,656     1,656   1,656     1,656   1,656     1,656   1,656     1,656     1,656   1,656     1,656	National	崖				J	Sompetitive	الاباد Senstive	e Confident	RPD-2-001 ial Attachment 1
1407   15.964   16.964   16.	AEP Ohio OVEC Data 2015-2018						-			Page 1 of 4
Jul-15         Aug-15         Sep-15         Oct-15         Nov-15         Dec-15         Jan-16         Feb-16           393 <th>Based on Aug market data assum</th> <th>iptions in 20</th> <th>13 LRP fore</th> <th>cast</th> <th></th> <th></th> <th></th> <th></th> <th></th> <th></th>	Based on Aug market data assum	iptions in 20	13 LRP fore	cast						
acity UCAP  393 393 393 393 393 393 393 393 393 3		Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16
Figy (GWH) and Charge* for capacity (\$/MW-Day)  136 136 136 136 136 136 136 136 136 13	OVEC Capacity UCAP	393	393	393	393	393	393	393	393	393
revenue (\$600)  1,602	OVEC Energy (GWH)									
For capacity (\$/MW-Day)	OVEC Demand Charge*									
## month   30   31   31   30   31   31   31   30   31   31	RPM price for capacity (\$/MW-Day)	136	136	136	136	136	136	136	136	136
tevenue (\$ 000)	# Days in month	30	31	31	30	31	30	31	31	29
renue (\$000) Sis (\$000	Capacity Revenue (\$ 000)	1,602	1,656	1,656	1,602	1,656	1,602	1,656	1,656	1,549
t (Demand + Fuel)  1,812 (209) 323 2,252 2,625 2,615 1,990 694  7 mo  7 mo  7 mo  11.407 15.964 15.996 8.691	Energy Market Price (\$/MWH) Energy Revenue (\$000) OVEC Cost [NEC+some var] (\$/MWH) OVEC COGS (\$000) OVEC Energy Gross Margin									
enue (Capacity & Energy) t (Demand + Fuel)  1,812 (209) 323 2,252 2,625 2,615 1,990 694  7 mo  7 mo  7 mo  11.407 15.964 15.996 8.691										
1,812       (209)       323       2,252       2,625       2,615       1,990       694         7 mo       5 mo         2015       2016       2017       2018         11,407       15,964       15,996       8,691	OVEC Revenue (Capacity & Energy) OVEC Cost (Demand + Fuel) OVEC Total									
15 2016 2017 2 407 15.964 15.996	PPA Rider	1,812	(508)	323	2,252	2,625	2,615	1,990	694	1,326
15 2016 2017 2 407 15.964 15.996		•	7 mo			5 mo				
15.964 15.996		L	2015	2016	2017	2018				
		J	11.407	15,964	15,996	8.691				

Case No. 13-2385-EL-SSO

\*OVEC demand charge has been decreased \$10M annually (versus the projections from OVEC) to reflect lean improvements/process optimization

ent 1 of 4		393			59	30	669									78	
tachment Page 2 of	Nov-16	m		-			9									2,478	
Competitively- Senstive Confidential Attachment 1 Page 2 of 4	Oct-16	393			59	31	723									2,466	,
senstive Cor	Sep-16	393			59	30	669									2,056	
petitively- S	Aug-16	393			59	31	723									(187)	•
Com	Jul-16	393			59	31	723									(470)	•
	Jun-16	393			59	30	669									1,637	
	May-16	393			136	31	1,656									1,264	
	Apr-16	393			136	30	1,602									1,449	
	Mar-16	393			136	31	1,656									1,003	
AEP Ohio OVEC Data 2015-2018 ONFIDENTIAL Based on Aug market data assump		OVEC Capacity UCAP	OVEC Energy (GWH)	OVEC Demand Charge*	RPM price for capacity (\$/MW-Day)	# Days in month	Capacity Revenue (\$ 000)	Fnerov Market Price (\$/MWH)	Energy Revenue (\$000)	OVEC Cost [NEC+some var] (\$/MWH)	OVEC COGS (\$000)	OVEC Energy Gross Margin	OVEC Revenue (Capacity & Energy)	OVEC Cost (Demand + Fuel)	OVEC Total	PPA Bider	

IEU Set 2 RPD-2-001

Case No. 13-2385-EL-SSO

\*OVEC demand charge has been decrease

							POBLIC	VERSION	
Case No. 13-2385-EL-SSO IEU Set 2 RPD-2-001 Competitively- Senstive Confidential Attachment 1 Page 3 of 4		393	10		31				(1,005)
EU 9	Aug-17								(17)
III RP RP: Tach	٨								
13-2 al At	r	393			31				78)
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S Cor	$\vdash$	33			30				0
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O	Apr-17	393		<u>.</u> ,		59			2,475
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		393		59	31	723			91
	Mar-17	33		υ,		7			1,946
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	-17	393		S	, ,	653			2,363
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	17	393		59	31	723			1,580
	Jan-17								
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$\equiv$	Dec-16								2
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	5			M-D			(+) (\$/W	Energ	
				N/\$)		6	/MW	y & l	
5-20	5	٩	۱) rge*	city		\$ 00	e (\$/ 000)	pacit d + F	
201	<u>م</u>	, UC,	GW!	caba	ቱ	nne	t Pric Le (\$ C+sc 000)	(Cal	
AEP Ohio OVEC Data 2015-2018	:	OVEC Capacity UCAP	OVEC Energy (GWH) OVEC Demand Charge*	RPM price for capacity (\$/MW-Day)	# Days in month	Capacity Revenue (\$ 000)	Energy Market Price (\$/MWH) Energy Revenue (\$000) OVEC Cost [NEC+some var] (\$/MWH) OVEC COGS (\$000)	OVEC Energy Gross Margin  OVEC Revenue (Capacity & Energy)  OVEC Cost (Demand + Fuel)  OVEC Total	
AEP Ohio OVEC Dat	3	Cap	C Ene	price	/s in	city I	By M 3y Re 3y Cos 3 COC	OVEC Reve OVEC Cost OVEC Total	PPA Rider
AEP OVE	5	OVEC	OVEC	ZPM	♯ Daγ	Capa	Energ Energ OVEC	OVEC DVEC DVEC	PPA !
		_	- 0			•			

\*OVEC demand charge has been decrease

			PUBLIC VE	KSIUN	
×	393	31			1,985
Ne N		-			ਜ
Apr-18	393	30			2,216
Mar-18	393	31			1,637
Feb-18	393	28			1,918
N=18	393	31			934
Dec-17	393	31			1,637
Nov-17	393	30			1,865
Oct-17	393	31			1,767
Sen-17	393	30			1,483
Based on Aug market data assump	OVEC Capacity UCAP OVEC Energy (GWH) OVEC Demand Charge*	RPM price for capacity (\$/MW-Day) # Days in month Capacity Revenue (\$ 000)	Energy Market Price (\$/MWH) Energy Revenue (\$000) OVEC Cost [NEC+some var] (\$/MWH) OVEC COGS (\$000) OVEC Energy Gross Margin	OVEC Revenue (Capacity & Energy) OVEC Cost (Demand + Fuel) OVEC Total	PPA Rider
	Sen-17 Oct-17 Nov-17 Dec-17 Jan-18 Feb-18 Mar-18 Apr-18	arket data assump    Sep-17	t data assump  Sep-17 Oct-17 Nov-17 Dec-17 Jan-18 Feb-18 Mar-18 May-18  393 393 393 393 393 393 393 393 393 39	data assump           Sep-17         Oct-17         Nov-17         Dec-17         Jan-18         Feb-18         Mar-18         Apr-18         May-18           AW-Day)         30         31         30         31         31         30         31           (5/MWH)         (5/MWH)	Sep.17 Oct-17 Nov-17 Dec-17 Jan-18 Feb-18 Mar-18 May-18 May-18 393 393 393 393 393 393 393 393 393 39

\*OVEC demand charge has been decrease

Exhibit KMM-6

CONFIDENTIAL

Power Curve: AEP-CARBON Market Date: LTF FT 2013H1 Base Nominal 2013 C9 27 xlsx

<u>25</u> 135.5 922 228.72 252.75 101.9 98.4 102.3 263.77 151.5 2,198 217.16 87.5 129.6 2026 61.8 6, 153.31 61,36 24.7 36,6 2,199 23.0 34.0 2,199 28.7 42.5 2,199 # 2 27.4 45.87 2,189 84.27 38.0 \$6.3 2,199 23.6 58,65 35.0 78.53 3,6 46.9 60.02 24.2 OVEC Total

Summary Financial Statement

Spread Option Model Only

Philipped & Confidential Prepared of the Request of Counsed 37.96 15.3 (15.58) (6.3) (119.86) (48,3) (71.6) \$100 Million - Fleeting Tates LOC Beaves District - Andon's real Foundary 2009 A.D.
\$100 Million - Foundary and Foundary 2009 A.D.
\$100 Million - Scripty Beaves District - Andon's Remark 2010-A83
\$100 Million - Scripty Beaves District - IAA The Service 2010-A83
\$100 Million - Scripty Beaves District - IAA The Service 2010-A83
\$100 Million - Scribty Beaves District - IAA The Service 2010-A83
\$100 Million - Scribty Beaves Compared AD Projected Capital Intervenements and Deal Costs (EVPA Component AD Projected Administration and Marinhamance Costs (CPA Component B) Projected Administration and Marinhamance Casts (CPA Component B) Projected Component B) Projected Administration and Marinhamance Casts (CPA Component B) Projected Component B) Pro Add Baals Total Transmission Coett Frem Demand Charge
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Properbor Coetts (ICPA Compount B)
Total Properbor of transmis and a rund/lyers paid 2008-2013.
Total Properbor Stat \$3,000 Coetts (ICPA Compount B)
Capabl Irrovonerate Root Coetts (ICPA Compount B)
Liabo Countries (ICPA Compount B)
Liabo Countries (ICPA Compount B)
Total Properbor Transmission Coetts (ICPA Compount B))
Seedia Strowers Transmission Coett Projected Ammai Capital Improvement Dosis (sortuding SCR, IPRB Coal Sortot, FCD and Other Financial Proposition)
Projected Kings CO Levilli Capital Coals or Proside State American Experient Projected Capital Coals for Prison 2-4 and Landill Capital Coals for Prison 2-4 and Landill Experient Projected Capital Foundary (Administry Coal)
Scott Capital Capital Capital Capital Coals for Prison 2-4 and Landill Experient Projected Capital Ca 571/2013 Demand Charge Extrinsic Value Fuel + VOM Average Price (Generation-Wid.) (\$/Mwh) Memo: Fwd Power Strips (Avg. ALL Hrs.) NOx (Sessonal) Emission Rate (bs/MMBtu) Revenues Capacity (five)
Midinarun Turn Down (Mw)
Capacity Factor
Net Generation (Gwh)
Fuel Impa (GOO MWBiu)
Fuel Impa (GOO MWBiu)
Fuel Impa (Kox Sassenan) (GOO MWBiu) Other Incremental Margin: (\$KweYr,)
UGAP Marker Value
SOZ Allowance Credits (@ Marker)
NOX Allowance Credits (@ Marker)
GROSS MARGIN - Total NET INCOME CONTRIBUTION Mercury Emissions (19s)
Mercury Emissions (19s)
SOZ Emissions (40n)
SOZ Emissions (40n)
NOX (Seasonall Emissions (40ns) CO2 Emission Rate (Ibs/MMBtu) GROSS MARGIN - Energy Heat Rate - Avg. (Btuffwh) CO2 Emissions (ktons) Income Taxes Est 40.3% ninnaio Value - Cost of Sales (S/Nwh) Fuel + VOM EBI

nt 2.xlsx

IEU RPD 2-001 Competitively-Sansitive Confide

Case No. 13-2385 EL-SSO 15U Set 2 RPD-2-001 Competitively-Sensitive Confidential Attachment 2 Page 2 of 7

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Ohio Total (19.9%) Summary Financial Statement Spread Option Model Only

Power Curve: AEP-CARBON
Market Date: LTF\_FT\_2013H1\_Base\_Nominal\_2013\_09\_27.xlsx

438   438	(\$Millions)	2015	2016	2017	2018	2019	2020	2021	2022	2023
n (Gwh) n (Swh) n (Swh	Capacity (Mw)	438	438	438	438	438	438	438	438	438
on m (Gwh) on MMBtu on MMBtu on MMBtu sion Rate sions (thons sion Rate sions (thons sion Rate onal) Em onal) Em OM MARGIN h) on MARGIN on MARGIN	Minimum Turn Down (Mw)									
n (Gwh) D MMBtu D MMBtu N Seaso N M Seaso	Capacity Factor									
MARGIN MA	Net Generation (Gwh)									
x Seaso x Seaso sis (ktons sion Rate sion Rate sion Rate sion Rate sion Rate sion Rate (Value CVAI OM	Fuel Input (000 MMBtu)									
wance Comment of the	Fuel Input (Nox Seasonal) (000 MMBtu)									
is (ktons sie (ktons sion Rate sions (Rate sions (Rate sion Rate ion Rate i	Heat Rate Avg. (Btu/Kwh)									
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onal) Emonal Consults (Value OM	NOx (Seasonal) Emissions (ktons)									
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wance Cowarice (Comment of Comment of Commen	Fuel + VOM									
h) OM MARGIN h) -Yr.) -Yr.) larket Va owance C owance C owance C owance C owance C owance C	Average Price (Generation-Wtd.) (\$/Wwn)									
h) OM MARGIN h) -Yr.) larket Va owance C owance C in ARGIN MARGIN -Yr.)	Memo: Fwd Power Strips (Avg. ALL Hrs.)									
h) OM MARGIN  Th) -Yr.) larket Va owance C  Wance C  Wance C  WARGIN	ost of Sales									
GROSS MARGIN - Energy (\$/Mwt) (\$/Mwt) (\$/Mwt/r.) Other Incremental Margin: (\$/Mwt/r.) UCAP Market Value SOZ Allowance Credits (@ Market) NOX Allowance Credits (@ Market) (\$/Kwt/r.) (\$/Kwt/r.) (\$/Kwt/r.) (\$/Kwt/r.)	(TwW/S)									
(SMWr) (SMWr) (SMWr) (SMW-Yr.)  Other Incremental Margin: (SKW-Yr.)  UCAP Market Value SO2 Allowance Credits (@ Market)  NOX Allowance Credits (@ Market)  GROSS MARGIN - Total (SKW-Yr.) (SKW-Yr.) (SKW-Yr.) (SKW-Yr.)	Fuel + VOM									
(S/Nwt) (S/Nwt) (S/Nwt) (S/Nwt-Yr.)  Other Incremental Margin: (S/Nw-Yr.)  UCAP Market Value SO2 Allowance Credits (@ Market) NOX Allowance Credits (@ Market) (GROSS MARGIN - Total (S/Nw-Yr.) (S/Nw-Yr.) (S/Nw-Mb.) (S/Nw-Mb.)	GROSS MARGIN - Fnerry									
Other Incremental Margin:  (\$/Kw-Yr.)  UCAP Market Value \$\text{SO2 Allowance Credits (@ Market)}\$  NOX Allowance Credits (@ Market)  GROSS MARGIN - Total  (\$/Kw-Yr.)  (\$/Kw-Yr.)  (\$/Kw-Yr.)	(Fig. 11) (44VS)									
Other Incremental Margin:  (\$IKw-Yr.) UCAP Market Value SO2 Allowance Credits (@ Market) NOX Allowance Credits (@ Market) GROSS MARGIN - Total (\$IKw-Yr.) (\$IKw-Yr.) (\$IKw-Mo.) SJ1/2013 Demand Charge)	(S/Kw-Yr.)									
(\$/Kw-Yr.) UCAP Market Value SO2 Allowance Credits (@ Market) NOx Allowance Credits (@ Market) GROSS MARGIN - Total (\$/Kw-Yr.) (\$/Kw-Yr.)	Other Incremental Margin:									
UCAP Market Value SO2 Allowance Credits (@ Market) NOx Allowance Credits (@ Market) GROSS MARGIN - Total (S/Kw-Yr.) (\$/Kw-Mc.) (\$/Kw-Mc.)	(\$/Kw-Yr.)									
SO2 Allowance Credits (@ Market)  NOx Allowance Credits (@ Market)  GROSS MARGIN - Total  (\$/Kw-Yr.)  (\$/Kw-Mo.)  S/1/2013 Demand Charge	UCAP Market Value									
NOx Allowance Credits (@ Market) GROSS MARGIN - Total (\$/Kw-Yr.) (\$/Kw-Mo.) 5/1/2013 Demand Charge	SO2 Allowance Credits (@ Market)									
GROSS MARGIN - Total (S/Kw-Yr.) (\$/Kw-Mo.) 5/1/2013 Demand Charge.	NOx Allowance Credits (@ Market)									
	GROSS MARGIN - Total									
	(S/Kw-Yr.)									
	ı									

14.17

5.7

3.7

7.6

4.7

6.3 8.3

8,

3.0

(1.2)

(9.6)

NET INCOME CONTRIBUTION

(\$/Kw-Yr.) - Income Taxes Est 40.3%

Ohio Tota Summary Finan

Ohio Total (19.9%)
Summary Financial Statement
Spread Option Model Only

Power Curve: AEP-CARBON

Market Date: LTF FT 2013H1\_Base\_Nominal\_2013\_09\_27.xlsx

2023

2022		9.13
2021		18.76
2020		11.67
2019		15.63
2018		11.94
2017		7.55
2016		(3.10)
2015		(23.85)
(acciling)	overnent Costs (ex- Capital Costs for Piapital Costs for Piapital Costs for Pitzation and Short- nsecured Notes - Secured Notes - Secured Notes - Secured Notes - Secured Notes - Soles - Series 2009- OK Backed Bonds OK GDA Tax Exempt 20 FA Tax E	EBIT
	+ ++++	

Summary Financial Statement Spread Option Model Only Ohio Total (19.9%)

Power Curve: AEP-CARBON

Market Date: LTF\_FT\_2013H1\_Base\_Nominal\_2013\_09\_27.xlsx

2023

2021

2022

2020

2019

2018

2017

2016

2015

(\$Millions)

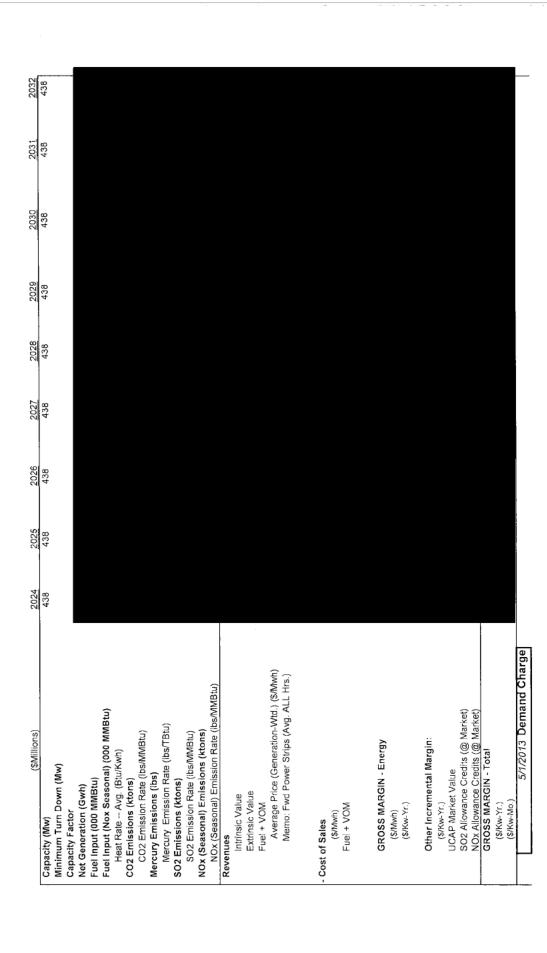
Notes

Generation, Revenues and Cost down to Gross Margin based on Asset Analysis Model. Fixed Costs with add back for transmission charges based on OVEC Demand Charge.

Competitively-Sensitive Confidential Attachment 2

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Page 6 of 7	
Competitively-Sensitive Confidential Attachment 2	
T00-7-014	

2-001

45.16 45.52 50,30 48.60 50.50 43.22 30.51 12.21 11.34 Assumption of financing due to multi-year project 2 Total Project Cost \$3,070,000 assuming avg int a Projected Clifty FGD Landfill Capital Costs for Pha Add Back: Total Transmission Cost: From Den Capital Improvements (not financed) (Projected C Labor Overheads (Projected Administration and G Special Services T&S (Projected Administration at Projected Annual Capital Improvement Costs (exc Projected Kyger FGD Landfill Capital Costs for Ph Projected Debt Expense Amortization and Short-T \$445 Million - 5.80% Senior Unsecured Notes - Se 5300 Million - 5.90% Senior Unsecured Notes - Se \$50 Million - 5.92% Senior Unsecured Notes - Ser S300 Million - 6,71% Senior Unsecured Notes - Se \$100 Million - Floating Rate Notes - Series 2009-A \$100 Million - Floating Rate LOC Backed Bonds -\$100 Million - 5.625% Bonds - OAQDA Tax Exem \$100 Million - Floating Rate Bonds - IFA Tax Exen \$200 Million - 5.00% Bonds - IFA Tax Exempt 20 Projected Capital Improvements and Debt Cost Projected Operation and Maintenance Costs (ICP) Projected Administration and General Costs (ICPA Projected Transmission and Dispatch Costs (ICP/ Projected Postretirement Benefit Obligation (ICPA Projected Decommissioning and Demolition Oblig. Projected Transmission and Dispatch Costs (ICPA Debt Cost - Capital Project 8 Gas Circuit Breakers Property Tax (Projected Taxes (ICPA Component \$100 Million - Floating Rate - IFA Tax Exempt 201 Total Projected Demand Costs (ICPA Components) Projected ROE Costs (ICPA Component D) Projected Taxes (ICPA Component C) Total Transmission Cost (\$/Kw-Yr.) EBIT

27.0 18.2

18.3 27.2

20.3 30.0

19.6 29.0

20.4 30.1

17.4

12.3

9

4.6 6.8

NET INCOME CONTRIBUTION

Income Taxes Est 40.3%

25.8

18.2

(\$Millions)	

Notes Generation, Revenues and Cost down to Gross Fixed Costs with add back for transmission ch

Exhibit KMM-7

CONFIDENTIAL

2,198 87.45 35.2 112.55 65 2,199 803 150.89 151.36 171.50 69 2,199 61.0 105.08 2,198 423 32 23 13.0 2024 16.4 Market Date: Price Forecast Nominal FTCA CSAPR2 2011 11 22 xts 2,199 60.42 24.3 2.139 14.0 2,199 80,47 32,4 Power Curve: AEP-CARBON 2,139 87.06 27.0 2,159 96.23 38.4 2018 69.80 28.1 Spread Option Model Only Privileged & Confidential Prepared at the Request of Course 34.73 14,0 Summary Financial Statement OVEC Total 37.89 153 (46.2) (114.72) Projected Kyper TOD Leads Capital Capital Robin Projected Kyper TOD Leads Capital Robin Projected Capi Projected Operation and Machinemous Costs (ICPA Component 8)
Projected Administration and General Costs (ICPA Component 8)
Projected Tearnisistation and Delegach Costs (ICPA Component 8)
Projected Tearnisistation and Delegach Costs (ICPA Component 8)
Projected Tearnisistation and Delegach Component 9
Projected Security Costs (ICPA Component 9)
Projected Decorrings and Obmillion Obligation (ICPA Component 8)
Total Projected Demand Costs (ICPA Component 8) Add Back Tetal Transmission Cost: From Demand Charge
Projected Transmission To Upgeth Crost (CPA Component S)
Projected Transmission Throughout Crost (CPA Component S)
Passurption of Mannies (Protect S)
Projected Component (Protect S)
Projected Captaining ang Int at 4% 30gra
Captail Improvement for Captaining ang Int at 4% 30gra
Captail Improvement for Captaining ang Int at 4% 30gra
Leadr Overheads (Projected Taxes (CPA Component C))
Leadr Overheads (Projected Administration and General Costs (ICPA Component B))
Total Transmission Cast
Internative Component S)

Total Transmission Cast
Internative Component B) 5/1/2013 Demand Charge Projected Annual Capital Improvement Costs (excluding SCR, PRB Coal Switch, FGD and Other Financed Project Capacity (Mw)
Minimum Tunn Down (f/w)
Capacity (British Tunn)
Capacity (British Tunn)
Capacity (British Tunn)
Feel Insuer (Too Minish)
Feel Insuer (Too Minish)
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Martin Refers And (Bushalla))
Martin Refers And (Bushalla)) hrtrasi Value Exfirst Value Fuel volue Average Phoe (Senention-Wid.) (SiMMh.) Meno: Fvel Pover Strips (Avg. ALL Hrs.) Mercury Emissions (this amendation) wherevery Emissions (this amendation) and Emissions (the minimal management of the minimal management (the minimal management (the minimal management (the minimal management ) and (desemble). Emissions (the minimal management ) and (desemble) Emissions (the minimal management). (SYN-Y7)
UCAP Market Value
SO2 Allowance Creatis (@ Market)
NO2 Allowance Creatis (@ Market)
GROSS MARGHT - Total Other Incremental Margin: GROSS MARGIN - Energy Income Taxes Est 40.3% Cost of Sales (\$/Mmh) Fuel + VOM

IEU RPD 2-001 Competitively-Sensitive Confidential

24.4

0.0

8.9

41.7

20.7

22.7

(88.5)

NET INCOME CONTRIBUTION

							Competitive	Case No. 13-2385-EL-SSO IEU Set 2 RPD-2-001 Competitively-Sensitive Confidential Attachment 3 Page 2 of 7	Case No. 13-2385-EL-SSO IEU Set 2 RPD-2-001 onfidential Attachment 3 Page 2 of 7	385-EL-SSO  EU Set 2  RPD-2-001  achment 3  Page 2 of 7
CONFIDENTIAL	Ohio Total Summary Financial Statement Spread Option Model Only	otal :ial Statem Model Onl	ent ly		Pow	Power Curve: AEP-CARBON Market Date: Price_Forecast	ARBON orecast_Nominal_	AEP-CARBON Price_Forecast_Nominal_FTCA_CSAPR2_2011_11	011 11 2	
Capacity (Mw) Minimum Turn Down (Mw)	2015	2016 438	2017	2018	2019	<u>2020</u> 438	2021	2022.	2023	
Capacity Factor  Net Generation (Gwh)  Fuel Input (000 MMBtu)  Fuel Input (Nox Seasonal) (000 MMBtu)  Heat Rate Avg. (Btu/Kwh)  CO2 Emissions (ktons)  CO2 Emission Rate (Ibs/MMBtu)										
Mercury Emissions (lbs) Mercury Emission Rate (lbs/TBtu) SO2 Emissions (ktons) SO2 Emission Rate (lbs/MMBtu) NOx (Seasonal) Emissions (ktons) NOx (Seasonal) Emission Rate (lbs/MMBtu)										
Revenues Intrinsic Value Extinsic Value Fuel + VOM Average Price (Generation-Wtd.) (\$/Mwh) Memo: Fwd Power Strips (Avg. ALL Hrs.)										
- Cost of Sales (\$/Awth) Fuel + VOM										
GROSS MARGIN - Energy (\$/Mwr) (\$/Kw-Yr.)										
Other Incremental Margin: (\$/Kw-Yr.) UCAP Market Value SO2 Allowance Credits (@ Market) NOx Allowance Credits (@ Market)										
GROSS MARGIN - Total (\$/Kw-Yr.) (\$/Kw-Mo.)										
5/1/2013 Demand Charge	٥l									

ATTIVE OF THE PERSON OF THE PE							Competitiv	Case No. 13-2385-EL-SSO   IEW Set 2   RPD-2-001     RPD-2-001     RPD-2-001     RPD-2-001     RPD-2-001     RPD-3-001     RPD-3-	Case No. 13-2385-EL-SSO  EU Set 2   RPD-2-001   Case 2   Case 2	385-EL-SSO IEU Set 2 RPD-2-001 tachment 3 Page 3 of 7
THE CONTRACT OF THE PARTY OF TH	Ohio Total Summary Financial Statement Spread Option Model Only	Ohio Total ummary Financial Statemel Spread Option Model Only	tement Only		Pow	Power Curve: AEP-CARBON Market Date: Price Forecast	ARBON orecast Nominal	Power Curve: AEP-CARBON Market Date: Price_Forecast_Nominal_FTCA_CSAPR2_2011_11_22	011_11_2	
(\$Millions) Projected Annual Capital Improvement Costs (exclu Projected Kyger FGD Landfill Capital Costs for Phasil Projected Clifty FGD Landfill Capital Costs for Phasil Projected Detail Costs Senior Unsecured Notes - Series S300 Million - 5.90% Senior Unsecured Notes - Series S300 Million - 5.71% Senior Unsecured Notes - Series S100 Million - Floating Rate Notes - Series 2009-A \$100 Million - Floating Rate LOC Backed Bonds - O \$100 Million - Floating Rate LOC Backed Bonds - O \$100 Million - Floating Rate Loc Backed Bonds - O \$100 Million - Floating Rate - IFA Tax Exempt 2012 Projected Capital Improvements and Debt Costs (ICPA Projected Capital Improvements and Debt Costs (ICPA Projected Administration and General Costs (ICPA Projected Administration and Binpatch Costs (ICPA Projected Postreitement Benefit Obligation (ICPA Component C) Projected Decommissioning and Demolition Obligat Total Project Osts (ICPA Component Benefit Obligation (ICPA Cepted Decommission and Dispatch Costs (ICPA Component Costs (ICPA Component Costs (ICPA Component Costs) (ICPA Compon	2015 ind Charge 18-2013, %, 30yrs	2016	2017	2018	<u>2018</u>	2020	<u>2021</u>	2022	2023	
Total Transmission Cost	(22.83)	7.56	6	13.89	2. 2. 2.	13.34	16.01	20,00	12.02	
(\$/Kw-Yr)	(22:03)	P	6							
me Taxes Est 40.3%	(9.2)	3,0	2.8	5.6	7.6	4.0	6.5	2.8	8 6	
NET INCOME CONTRIBUTION	(13.6)	4.5	4.1	8.3	11.3	8.0	9.6	4.1	7.2	

Case No. 13-2385-€L-SSO	IFU Set 2	RPD-2-001	Competitively-Sensitive Confidential Attachment 3	Page 4 of 7

Ohio Total

Summary Financial Statement Spread Option Model Only

2018

2019

2020

Market Date: Price\_Forecast\_Nominal\_FTCA\_CSAPR2\_2011\_11\_23

Power Curve: AEP-CARBON

2022

2023

2021

2017

2016

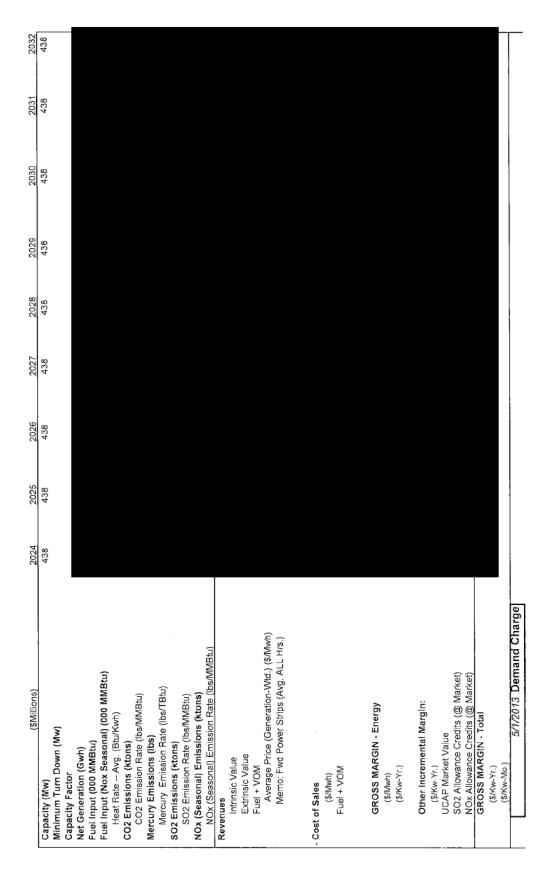
2015

(\$Millions)

Generation, Revenues and Cost down to Gross Margin based on Asset Analysis Model. Fixed Costs with add back for transmission charges based on OVEC Demand Charge.

Page 5 of 7





17.40

10.4

19.5

17.9

20,4

18.0

12.5

3.8

NET INCOME CONTRIBUTION

fεU Set 2 RPD+2-001 Competitively-Sensitive Confidential Attachment 3 Page 6 of 7

2032

2031 22.40 9.0 2030 32.66 13.2 2029 30.03 121 2028 34.13 13.8 2027 30.12 12.1 2026 20.91 8.4 2.6 6.41 8.12 3.3 \$100 Million - Floating Rate LOC Backed Bonds - O \$200 Million - 5.00% Bonds - IFA Tax Exempt 2012 Projected Postretirement Benefit Obligation (ICPA C Projected Decommissioning and Demolition Obligat Total Projected Demand Costs (ICPA Componen Add Back: Total Transmission Cost: From Dem: Total Project Cost \$3,070,000 assuming avg int at 4 Property Tax (Projected Taxes (ICPA Component C Projected Annual Capital Improvement Costs (exclu Projected Kyger FGD Landfill Capital Costs for Phas Projected Clifty FGD Landfill Capital Costs for Phas Projected Debt Expense Amortization and Short-Ter \$445 Million - 5.80% Senior Unsecured Notes - Seri \$300 Million - 5.90% Senior Unsecured Notes - Seri \$50 Million - 5.92% Senior Unsecured Notes - Serie \$300 Million - 6.71% Senior Unsecured Notes - Seri \$100 Million - 5.625% Bonds - OAQDA Tax Exempt \$100 Million - Floating Rate Bonds - IFA Tax Exemt Projected Capital Improvements and Debt Costs Projected Administration and General Costs (ICPA: Projected Transmission and Dispatch Costs (ICPA) Projected Transmission and Dispatch Costs (ICPA) Assumption of financing due to multi-year project 20 Capital Improvements (not financed) (Projected Ca Labor Overheads (Projected Administration and Ger \$100 Million - Floating Rate - IFA Tax Exempt 2012-Debt Cost - Capital Project 8 Gas Circuit Breakers ( Special Services T&S (Projected Administration and Projected Operation and Maintenance Costs (ICPA \$100 Million - Floating Rate Notes - Series 2009-A Projected ROE Costs (ICPA Component D) Projected Taxes (ICPA Component C) (\$Millions) Total Transmission Cost Income Taxes Est 40.3% (\$/Kw-Yr.) EBIT

		2024			
2.x/s	12/2/2	Skylllions)	Notes Co.	Generation, Revenues and Cost down to Gross II	Fixed Costs with add back for transmission char

Exhibit KMM-8

### OHIO POWER COMPANY'S RESPONSE THE OFFICE OF THE OHIO CONSUMERS' COUNSEL'S

#### DISCOVERY REQUEST PUCO CASE NO. 13-2385-EL-SSO et al. FIFTH SET

#### INTERROGATORY

INT-5-094 Please refer to your response to IEU Set 2, INT-2-001, Confidential Attachment 1 and provide the following information:

- a. Provide a detailed description of each row;
- b. Identify the source of all raw data used in each row;
- c. Identify the August market data assumptions underlying the forecast; and
- d. Identify how the August market data assumptions (and any other assumptions) were developed and, if they were developed through a computer model, identify the computer model (including manufacturer, product model and serial number), and provide all inputs and assumptions.
- e. Please identify the date the forecast was prepared and the person(s) who was/were responsible for preparing the forecast.

#### RESPONSE

a. Detailed description of each row.

**OVEC capacity UCAP:** The unforced capacity available to PJM for AEP Ohio's portion of the OVEC units.

OVEC Energy (GWH): The forecasted energy produced and sold in a particular month.

**OVEC Demand Charge:** The demand charge OVEC bills AEP Ohio.

RPM price for capacity (\$/MW-Day): The PJM reliability pricing model price of capacity in that month.

# Days in month: Simply the number of days in the particular month used for calcuations.

Capacity Revenue (\$ 000): Revenue associated with the sale of the AEP Ohio's portion of OVEC UCAP capacity into the PJM.

Energy Market Price (\$/MWH): Market energy price for sale.

Energy Revenue (\$000): Revenue associated with selling AEP Ohio's portion of OVEC energy.

OVEC Cost [NEC + some var] (\$/MWH): Rate charged by OVEC for producing energy, including Net Energy Cost and other variable costs.

OVEC COGS (\$000): AEP Ohio's portion of OVEC cost of goods sold.

OVEC Energy Gross Margin: Energy Revenue minus COGS.

### OHIO POWER COMPANY'S RESPONSE THE OFFICE OF THE OHIO CONSUMERS' COUNSEL'S

#### DISCOVERY REQUEST

PUCO CASE NO. 13-2385-EL-SSO et al.

#### FIFTH SET

OVEC Revenue (Capacity & Energy): Total AEP Ohio OVEC monthly revenue, from adding capacity and energy revenue lines

OVEC Cost (Demand + Fuel): Total AEP Ohio OVEC monthly costs, from adding the demand costs and the variable costs, which includes fuel.

**OVEC Total:** Difference between the previous two lines, the net margin from AEP Ohio's OVEC share.

**PPA Rider:** The amount of the purchased power rider either charged to customers or credited them based upon AEP Ohio's OVEC sales.

b. Source of raw data (N/A indicates a calculation—the line is not "raw data")

OVEC capacity UCAP: AEP Resource Planning and Analysis.

OVEC Energy (GWH): AEP Resource Planning and Analysis.

OVEC Demand Charge: Forecast from OVEC. (modified based upon process improvement)

RPM price for capacity (\$/MW-Day): PJM.

# Days in month: Calendar.

Capacity Revenue (\$ 000): N/A

Energy Market Price (\$/MWH): AEP Resource Planning and Analysis.

Energy Revenue (\$000): N/A

OVEC Cost [NEC + some var] (\$/MWH): Forecast from OVEC.

OVEC COGS (\$000): N/A

OVEC Energy Gross Margin: N/A

OVEC Revenue (Capacity & Energy): N/A

OVEC Cost (Demand + Fuel): N/A

OVEC Total: N/A PPA Rider: N/A

- c. See OCC INT-094 Confidential Attachment 1
- d. See the Company's response to OCC INT-5-095, part c.
- e. This forecast was finalized in conjunction with the ESP III financial forecast filed on Dec 20, 2013 using market data assumptions September 2013 and October 2013 as prepared by various support functions at the request of Company witness Allen.

Prepared by: William A. Allen

### OHIO POWER COMPANY'S RESPONSE THE OFFICE OF THE OHIO CONSUMERS' COUNSEL'S

## DISCOVERY REQUEST PUCO CASE NO. 13-2385-EL-SSO et al. FIFTH SET

#### INTERROGATORY

INT-5-095 Please refer to your response to IEU Set 2, INT-2-001, Confidential Attachments 2 and 3, and provide the following information:

- a. Provide a detailed description of each row;
- b. Identify the source of all raw data used in each row;
- c. If inputs were developed through a computer model, identify the computer model (including manufacturer, product model and serial number), and identify all inputs and assumptions;
- d. Please explain the difference between Confidential Attachments 2 and 3, including any differences in inputs and assumptions; and
- e. Please identify the date the Summary Financial Statements were prepared and the person(s) who was/were responsible for preparing the Summary Financial Statements.

#### RESPONSE

- a. A line by line description is presented in OCC-INT-5-095 Attachment 1. Lines 49 through 82 are described in OCC-INT-5-095 Attachment 2.
- b. Raw input data includes

I.

- II. Fuel forecast data is provided by AEP's Fuels Emissions and Logistics and AEP's Fundamentals Analysis Group
- III. Unit performance characteristics, ie. heat rate, availability, maximum and minimum load capability, emission rates, is provided by AEP's and OVEC's engineering organizations.
- IV. Energy price forecast is provided by AEP's Fundamentals Analysis Group.
- V. Capacity price forecast is provided by AEP's Fundamentals Analysis Group.
- c. The primary tool used for developing the long-term, energy-related commodity pricing forecasts is the AURORAxmp Electric Market Model, developed and maintained by EPIS, Inc. (http://epis.com/), version 10.2.1005. There is no unique serial number, but it is licensed to American Electric Power Service Corporation. The AuroraXMP model iteratively generates

## OHIO POWER COMPANY'S RESPONSE THE OFFICE OF THE OHIO CONSUMERS' COUNSEL'S DISCOVERY REQUEST

PUCO CASE NO. 13-2385-EL-SSO et al. FIFTH SET

locational, but not company-specific, long-term capacity expansion plans, annual energy dispatch, fuel consumption and emission totals from inputs including fuel, load, emissions and capital costs, among others. The forecasts developed include: 1) monthly and annual locational power prices (in both nominal and real \$), 2) prices for various qualities of Central Appalachian ("CAPP"), Northern Appalachian ("NAPP"), Illinois Basin ("ILB"), Powder River Basin ("PRB") and Colorado coals, 3) monthly and annual locational natural gas prices, including the benchmark Henry Hub, 4) uranium fuel prices, 5) SO<sub>2</sub>, NO<sub>x</sub> (summer and annual) and CO<sub>2</sub> values, 6) locational heat rates, 7) capacity values, 8) renewable energy subsidies and 9) inflation factors.

- d. The difference between Attachments 2 and 3 is that Attachment 2 represents an updated Fundamentals forecast. In the upper right corner of page 1 for each attachment the Fundamentals forecast market date is shown. Please see Attachment #OCC-INT-5-095 for the gap analysis in Confidential Attachments 2 and 3 related to the Long-Term North American Energy Market Forecast.
- e. Attachment 2 was prepared on October 30, 2013. Attachment 1 was prepared on September 5, 2013. The forecast statements were prepared by various support functions at the request of Company witness Allen.

Prepared by: William A. Allen

Exhibit KMM-9

CONFIDENTIAL

#### OHIO POWER COMPANY'S RESPONSE

#### THE OFFICE OF THE OHIO CONSUMERS' COUNSEL'S

## DISCOVERY REQUEST PUCO CASE NO. 13-2385-EL-SSO et al. ELEVENTH SET

#### INTERROGATORY

- INT-11-272 IEU-INT-2-001 Conf. att. 1 page 1 states, "\* OVEC demand charge has been decreased \$10M annual (versus the projections from OVEC) to reflect lean improvements/process optimization"
  - a. Identify the demand charge projections from OVEC;
  - b. Has OVEC and/or you committed to making these "lean improvements/process optimization"?
  - c. Has OVEC or you committed to reducing the demand charge \$10M annually based on the "lean improvements/process optimization"?
  - d. Do you commit to the \$10M annual reduction in demand charge for purposes of the PPA Rider even if OVEC or you fail to implement the "lean improvements/process optimization"?

#### RESPONSE

a. OVEC provides yearly demand charges with OPCo (including CSP) having a 19.93% share.

2015: Total =	OPCo @ 19.93% =
2016: Total =	OPCo @ 19.93% =
2017: Total =	OPCo @ 19.93% =
2018: Total =	OPCo @ 19.93% =
,	-

- b. No.
- c. No.
- d. No.

Prepared by: William A. Allen

**Exhibit KMM-10** 

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

#### INTERROGATORY

INT-3-025

Is the continuation of the Distribution Credit Rider the only quantifiable benefit of the proposed ESP (as compared to the MRO) or are there other quantifiable benefits as well? Please identity any other benefits that the Company has quantified. (Reference: Allen testimony, page 5, lines 15-18.)

#### RESPONSE

The only benefit of the ESP that the Company has quantified at this time is the continuation of the Distribution Credit Rider. As indicated in the testimony of Company witness Allen (page 3 line 22 through page 4 line 1) "A comprehensive ESP can more holistically address many components of electric service, whereas a MRO is primarily a plan just for power procurement."

Prepared by: William A. Allen

Exhibit KMM-11

# OHIO POWER COMPANY'S RESPONSE TO INDUSTRIAL ENERGY USERS-OHIO'S DISCOVERY REQUEST PUCO CASE NO. 13-2385-EL-SSO et al. FIFTH SET

#### REQUEST FOR ADMISSION

RFA-5-001

Referencing IEU-Ohio Interrogatory 3-48 and AEP-Ohio's response thereto, admit that AEP-Ohio's proposed ESP tariffs do not provide shopping customers with the ability to avoid being billed twice for the non-market based transmission costs once AEP-Ohio implements the BTCR and assuming that the shopping customer is still billed for non-market based transmission costs from its CRES provider.

#### **RESPONSE**

Deny. Whether or not a customer will be billed twice for non-market based transmission costs will be dependent on the contract with their CRES provider.

Prepared by: Andrea E. Moore

Exhibit KMM-12

# OHIO POWER COMPANY'S RESPONSE TO INDUSTRIAL ENERGY USERS-OHIO'S DISCOVERY REQUEST PUCO CASE NO. 13-2385-EL-SSO et al. FIFTH SET

#### **INTERROGATORY**

INT-5-014

Referencing AEP-Ohio's response to IEU-Ohio Interrogatory 3-34, AEP-Ohio indicated that the proposed BTCR would "enable[] CRES providers to compete on a more uniform basis across Ohio." Will AEP-Ohio's BTCR include the exact same categories of transmission and transmission related costs and credits as Duke Energy Ohio, Inc.'s, FirstEnergy's, or the Dayton Power & Light Co.'s non-bypassable transmission riders?

#### RESPONSE

The Company's proposal generally includes the same major items as the other Ohio utilities. Based upon the Company's review of the provisions for other Ohio utilities, there are currently minor variances amongst the various other Ohio utilities.

Prepared By: Andrea E. Moore

Exhibit KMM-13

#### Summary of Switch Rates from EDUs to CRES Providers in Terms of Sales For the Month Ending December 31, 2013 (MWh)

Provider Name  Cleveland Electric Illuminating Company CRES Providers Total Sales EDU Share Electric Choice Sales Switch Rates	EDU Service Area CEI CEI CEI CEI	Quarter Ending 31-Dec 31-Dec 31-Dec 31-Dec 31-Dec	Year 2013 2013 2013 2013 2013	Residential Sales 120877 360642 481519 25.10% 74.90%	Commercial Sales 47523 496936 544459 8.73% 91.27%	Industrial Sales 48510 454212 502722 9.65% 90.35%	Total Sales 228568 1312107 1540675 14.84% 85.16%
Provider Name  Duke Energy Ohio CRES Providers Total Sales EDU Share Electric Choice Sales Switch Rates	EDU Service Area DUKE DUKE DUKE DUKE DUKE	Quarter Ending 31-Dec 31-Dec 31-Dec 31-Dec	Year 2013 2013 2013 2013 2013	Residential Sales 348067 335007 683074 50.96% 49.04%	Commercial Sales 87162 438815 525977 16.57% 83.43%	Industrial Sales 14739 421915 436654 3.38% 96.62%	Total Sales 457660 1314223 1771883 25.83% 74.17%
Provider Name  AEP - Ohio CRES Providers Total Sales EDU Share Electric Choice Sales Switch Rates	EDU Service Area AEP AEP AEP AEP	Quarter Ending 31-Dec 31-Dec 31-Dec 31-Dec	Year 2013 2013 2013 2013 2013	Residential Sales 1015544 379722 1395266 72.785% 27.215%	Commercial Sales 242958 955035 1197993 20.280% 79.720%	Industrial Sales 230193 1007334 1237527 18.601% 81,399%	Total Sales 1493773 2349176 3842949 38.870% 61.130%
Provider Name  The Dayton Power and Light Company CRES Providers Total Sales EDU Share Electric Choice Sales Switch Rates	EDU Service Area DPL DPL DPL DPL DPL	Quarter Ending 31-Dec 31-Dec 31-Dec 31-Dec	Year 2013 2013 2013 2013 2013	Residential Sales 267654 207358 475012 56.35% 43.65%	Commercial Sales 52026 238272 290298 17.92% 82.08%	Industrial Sales 5998 260676 266674 2.25% 97.75%	Total Sales 361273 773120 1134393 31.85% 68.15%

Source: PUCO, Energy & Environment

Note1: Total sales includes residential, commercial, industrial and other sales.

Note2: The switch rate calculation is intended to present the broadest possible picture of the state of retail electric competition in Ohio.

Appropriate calculations made for other purposes may be based on different data, and may yield different results.

Note3: "Total Sales" include "Other Sales" (e.g. street lighting).

Note4: CSP and OP have merged into AEP-Ohio

#### Summary of Switch Rates from EDUs to CRES Providers in Terms of Sales For the Month Ending December 31, 2013 (MWh)

Provider Name	EDU Service Area	Quarter Ending	Year	Residential Sales	Commercial Sales	Industrial Sales	Total Sales
Ohio Edison Company	OEC	31-Dec	2013	249799	51986	147153	460487
CRES Providers	OEC	31-Dec	2013	582031	500438	523541	1606930
Total Sales	OEC	31-Dec	2013	831830	552424	670694	2067417
EDU Share	OEC	31-Dec	2013	30.03%	9.41%	21.94%	22.27%
Electric Choice Sales Switch Rates	OEC	31-Dec	2013	69.97%	90.59%	78.06%	77.73%

Provider Name	EDU Service Area	Quarter Ending	Year	Residential Sales	Commercial Sales	Industrial Sales	Total Sales
Toledo Edison Company	TE	31-Dec	2013	63059	13112	103750	181740
CRES Providers	TE	31-Dec	2013	162771	154199	363313	680332
Total Sales	TE	31-Dec	2013	225830	167311	467063	862072
EDU Share	TE	31-Dec	2013	27.92%	7.84%	22.21%	21.08%
Electric Choice Sales Switch Rates	TE	31-Dec	2013	72.08%	92.16%	77.79%	78.92%

Source: PUCO, Energy & Environment

Note1: Total sales includes residential, commercial, industrial and other sales.

Note2: The switch rate calculation is intended to present the broadest possible picture of the state of retail electric competition in Ohio.

Appropriate calculations made for other purposes may be based on different data, and may yield different results.

Note3. "Total Sales" include "Other Sales" (e.g. street lighting).

Note4: CSP and OP have merged into AEP-Ohio

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in

Case No(s). 13-2385-EL-SSO, 13-2386-EL-AAM

Summary: Testimony Public Version of Kevin M. Murray on behalf of Industrial Energy Users-Ohio electronically filed by Mr. Steven T Nourse on behalf of Ohio Power Company