EXHIBIT NO. ___________

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Power Company and Columbus Southern Power Company for Authority to Merge and Related Approvals.	)	Case No. 10-2376-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.	)	Case No. 11-346-EL-SSO Case No. 11-348-EL-SSO
In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Certain Accounting Authority	)	Case No. 11-349-EL-AAM Case No. 11-350-EL-AAM
In the Matter of the Application of Columbus Southern Power Company to Amend its Emergency Curtailment Service Riders	)	Case No. 10-343-EL-ATA
In the Matter of the Application of Ohio Power Company to Amend its Emergency Curtailment Service Riders	)	Case No. 10-344-EL-ATA
In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company.	)	Case No. 10-2929-EL-UNC
In the Matter of the Application of Columbus Southern Power Company for Approval of a Mechanism to Recover Deferred Fuel Costs Ordered Under Ohio Revised Code 4928.144	)	Case No. 11-4920-EL-RDR
In the Matter of the Application of Ohio Power Company for Approval of a Mechanism to Recover Deferred Fuel Costs Ordered Under Ohio Revised Code 4928.144	)	Case No. 11-4921-EL-RDR

TESTIMONY OF WILLIAM A. ALLEN
IN SUPPORT OF THE STIPULATION AND RECOMMENDATION
ON BEHALF OF
COLUMBUS SOUTHERN POWER COMPANY
AND
OHIO POWER COMPANY

Filed: September 13, 2011

INDEX TO DIRECT TESTIMONY OF
WILLIAM A. ALLEN

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO
TESTIMONY OF
WILLIAM A. ALLEN
IN SUPPORT OF THE SEPTEMBER 7, 2011
STIPULATION AND RECOMMENDATION

PERSONAL DATA

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is William A. Allen, and my business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am employed by the American Electric Power Service Corporation (AEPSC) as Director of Regulatory Case Management. AEPSC supplies engineering, financing, accounting, and planning and advisory services to the eleven electric operating companies of the American Electric Power System, two of which are Columbus Southern Power Company (CSP) and Ohio Power Company (OPCo).

Q. WOULD YOU PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. Yes. I received a Bachelor of Science in Nuclear Engineering from the University of Cincinnati in 1996 and a Master of Business Administration from the Ohio State University in 2004.

I was employed by AEPSC beginning in 1992 as a Coop Engineer in the Nuclear Fuels, Safety and Analysis department and upon completing my degree in 1996 was hired on a permanent basis in the Nuclear Fuel section of the same department. In January 1997, the Nuclear Fuel section became a part of Indiana Michigan Power Company (I&M) due to a corporate restructuring. In 1999, I transferred to the Business Planning section of the Nuclear Generation Group as a Financial Analyst. In 2000, I transferred back to AEPSC into the Regulatory Pricing and Analysis section as a Regulatory Consultant. In 2003, I transferred into the Corporate Financial Forecasting department as a Senior Financial Analyst. In 2007, I was promoted to the position of Director of Operating Company Forecasts. In that role, I was primarily responsible for the supervision of the financial forecasting and analysis of the AEP System's eleven operating companies, including CSP and OPCo. I was named to my current position in June 2010.

Q. WHAT ARE YOUR RESPONSIBILITIES AS DIRECTOR OF REGULATORY CASE MANAGEMENT?

A. I am primarily responsible for the supervision, oversight and preparation of major filings with state utility commissions and the Federal Energy Regulatory Commission.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN ANY REGULATORY PROCEEDINGS?

A. Yes. I have submitted testimony on behalf of I&M before the Michigan Public Service Commission and the Indiana Utility Regulatory Commission in a variety of cases. I have also testified on behalf of Appalachian Power Company in fuel related proceedings before the West Virginia Public Service Commission and the Virginia State Corporation Commission.

PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to describe various elements of the September 7, 2011 Stipulation and Recommendation (Stipulation) including the Generation Resource Rider (GRR), the Fuel Adjustment Clause (FAC) mechanism, the Distribution Investment Rider (DIR), the Storm Damage Recovery mechanism, the RPM Set-Aside Allotment Rules, the Phase In Recovery Rider (PIRR), Securitization of the PIRR regulatory assets, analysis of the quantifiable benefits of the ESP as compared to the expected results under a Market Rate Offer (MRO). Also, I provide *pro forma* financial statements that show the effect of the ESP on the Company for the duration of the plan.

Q. WHAT EXHIBITS ARE YOU SPONSORING?

A. I am sponsoring the following exhibits:

Exhibit WAA-1	Additional Information for the FAC
Exhibit WAA-2	Distribution Investment Rider
Exhibit WAA-3	Securitization Model
Exhibit WAA-4	Quantifiable Benefits of the ESP
Exhibit WAA-5	Pro Forma Financial Projections

GENERATION RESOURCE RIDER

Q. WILL ANY CHARGES BE INCLUDED IN CUSTOMER BILLS AS A DIRECT RESULT OF THE INCLUSION OF THE GRR PROVISION INCLUDED IN PARAGRAPH IV.1.d (PAGE 6) OF THE STIPULATION?

A. No. The GRR provision included in the Stipulation provides the Company with a mechanism to seek recovery of costs associated with the Turning Point solar project and the MR6 project during the term of the ESP, only if the Commission in a subsequent rider case approves a charge associated with one of those facilities. I have been advised by counsel that it is permissible under R.C. 4928.143(B)(2)(b) and (c) for the Commission to establish the GRR as part of approving AEP Ohio's 2012-2016 ESP with an initial rate of zero; there will only be a non-zero rate for the GRR after such time, if at all, that the Commission approves a project-specific charge for inclusion in the GRR as part of deciding a future rider case during the term of the ESP. It is also my understanding that, under Paragraph IV.1.d (page 6) of the Stipulation, the Parties have reserved their right to contest or otherwise take positions in the separate future cases that will determine whether to establish a nonbypassable charge and the appropriate level of the charge through the GRR.

Q. PARAGRAPH IV.1.d (PAGE 6) STATES THAT "PARTIES AGREE THAT ANY NONBYPASSABLE SURCHARGE APPROVED BY THE COMMISSION FOR INCLUSION IN THE GRR SHALL REFLECT THE NET COST OF THE FACILITY, INCLUDING FUEL AND OPERATING AND MAINTENANCE COSTS, ASSOCIATED WITH THE FACILITY." CAN YOU EXPLAIN WHAT IS MEANT BY "NET COST"?

A. Under Paragraph IV.1.r (page 13) of the Stipulation, the manner in which to include any dedicated resources of the EDU in any auction-based SSO procurement process will be developed in a stakeholder process and addressed in any competitive bid process. The net cost concept can work whether the GRR unit supplies SSO load or is purely a financial transaction in the PJM market. SSO customers would pay the bid price of the unit if the unit bids and clears into the SSO auction. All customers pay the net cost of the unit – the total cost less the revenues received including those received either from the SSO auction or from the PJM market. Per Paragraph IV.2.d (page 24) of the Stipulation, all revenues, products, and services of the EDU associated with GRR projects will be used to offset the Commission approved cost of the plant. In times when market prices are high it is likely that the GRR unit will clear the SSO auction and provide lower cost energy for SSO customers. Even if the unit does not clear the SSO auction and market prices subsequently rise customers will benefit from the GRR unit as a result of increased revenues received in the market.

FUEL ADJUSTMENT CLAUSE MECHANISM

Q. PLEASE REVIEW THE CURRENT FAC.

A. The Companies' current FAC began in 2009 as part of the 2009-2011 ESP. The FAC recovers the actual cost of fuel, purchased power, including capacity and other variable production costs such as environmental variable costs.

Q. PLEASE REVIEW THE ACCOUNTS INCLUDED IN THE CURRENT FAC.

A. The following is a list of accounts that are currently included in the FAC along with a brief description of each account.

- **501 Fuel –** This account includes the cost of fuel and transportation costs used in the production of steam for generation of electricity. For the

Companies, this is the vast majority of variable costs associated with energy production. The fees associated with the FAC audit are also charged to this account.

- **502 Steam Expenses (Environmental subaccounts) –** This account includes the cost of material and expenses used in the production of steam for the generation of electricity. In recent years the majority of the expenses recorded in this account have been for chemicals used in environmental equipment such as selective catalytic reduction (SCR) equipment and flue gas desulfurization (FGD) equipment. These chemicals are referred to as environmental consumables and include lime, limestone, trona, and urea. Lime and limestone are used in FGDs to remove sulfur from the post combustion process. Urea is the primary chemical agent used in the removal of NO_X. Trona is necessary to hinder the formation of SO_3, where an FGD and SCR are used in tandem. Any new environmental-related chemicals that may be required in the future will be included in the FAC.
- **509 Allowances –** This account records the cost of emission allowances to cover the emission of effluents such as SO_2 and NO_X.
- **518 Nuclear Fuel Expense –** This account includes the net amortization of the cost of nuclear fuel assemblies. The Companies do not own or operate a nuclear generating plant, are not currently incurring this cost, and are not expecting to incur this expense in the foreseeable future.

- **547 Fuel –** This account includes the cost of fuel used in facilities other than steam electric generation, such as a simple cycle gas peaking unit. Fuel costs for combined cycle gas plants are recorded in Account 501.
- **555 Purchased Power –** This account records the cost of electricity purchases including transactions under the AEP Pool and renewable energy contracts. It includes both energy and demand or capacity charges. PJM Interconnection L.L.C. (PJM) ancillary services that are recorded in Account 555 are not included in the FAC, but are included in the Transmission Cost Recovery Rider (TCRR).
- **507 Rents (Applicable subaccounts only) –** If a purchased power contract or unit power sale is required to be recorded as a lease per accounting rules, then the demand charge associated with the purchased power contract may be recorded in this account. Currently, there are no demand charges recorded in this account for the Companies.
- **557 Other Expenses (Power Supply – applicable subaccounts only) –** This account records the cost of renewable energy credits (RECs) to meet the renewable requirements of S.B. 221.
- **411.8 Gains from Disposition of Allowances and 411.9 Losses from Disposition of Allowances –** If gains or losses are experienced on the sale or other disposition of emission allowances, they are recorded in these accounts. Regular sales of allowances occur at the annual EPA auction resulting in gains each year. Sales to third parties are periodically made and settlements under the Federal Energy Regulatory Commission (FERC)

approved AEP Interim Allowance Agreement (IAA) can result in gains and losses.

- **Other Accounts and subaccounts –** If environmental, fuel, purchased power and renewable expenses or taxes are recorded in accounts or subaccounts not specifically mentioned in this testimony, the Companies may include them in the FAC. For example a carbon tax could be implemented and recorded in a tax account. Clearly, such a federally mandated carbon or energy tax would be recoverable though the FAC.

Q. DOES THE STIPULATION PROPOSE TO CONTINUE THE FAC IN THIS ESP?

A. Yes. However, under the Stipulation Account 557 and the REC expense are removed from the fuel clause, and REC expense will be recovered through a new AER. In addition, bundled purchased power products, or REPAs, currently recorded in Account No. 555, will be split into their REC and non-REC components. The REC component will be recovered through the AER and the non-REC portion will continue to be recovered through the FAC. I will discuss the AER later in this testimony. In addition, the Company will include in the AER the capital carrying costs associated with the solar panels installed on several of the Company’s service centers that are also currently included within FAC Account 557.

Q. IN ADDITION TO THE INFORMATION YOU HAVE ALREADY PROVIDED ON THE FAC, ARE YOU PROVIDING ANY ADDITIONAL INFORMATION PURSUANT TO O.A.C. 4901:1-35-03(C)(9)(a)?

A. Yes Exhibit WAA-5 provides additional information as specified in this section of the O.A.C., including the generating plants that the FAC cost pertains to and a narrative pertaining to the Company's procurement policies and procedures regarding FAC fuel costs.

Q. WILL CORPORATE SEPARATION HAVE AN IMPACT ON PURCHASED POWER COSTS?

A. Yes. If corporate separation occurs prior to June 1, 2015, the EDU will need to enter into bilateral contracts to procure the energy needed to serve its SSO obligation. These bilateral contracts will include recovery of costs that have historically been covered under base rates and not included in the FAC. These purchased power costs would be recoverable through the FAC. Paragraph IV.1.m (Page 8), provides that "the FAC will accommodate pass through of bilateral contractual arrangement between AEP Ohio (or the successor electric distribution utility entity) and an AEP affiliate as needed to supply generation services, provided that customers will pay the equivalent non-fuel and fuel generation rates as they would pay under the Stipulation prior to full legal corporation separation and Pool modification/termination."

DISTRIBUTION INVESTMENT RIDER

Q. PLEASE EXPLAIN THE DISTRIBUTION INVESTMENT RIDER.

A. The Stipulation (Paragraph IV.1.n, Page 8) provides for the approval of a rider that will allow carrying costs on incremental distribution plant. The carrying charge rate will include elements to allow the Company an 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 net investment associated with FERC Plant Accounts 360-374. The return earned on such plant will be based on the cost of debt of 5.34%, a cost of preferred stock of 4.40%, and a return on common equity of 10.50% utilizing a 47.06% debt, 0.19% preferred stock and 52.75% common equity capital structure. The net capital additions included for recognition under the DIR will reflect gross plant in-service incurred post-2000 adjusted for growth in accumulated depreciation. The DIR shall be adjusted quarterly to reflect in-service net capital additions. Capital additions recovered through riders authorized by the Commission to recover distribution capital additions, will be identified and excluded from the rider and the annual cap. The DIR annual revenue shall be capped at $86 million in 2012, $104 million in 2013 and $124 million in 2014 and the first five months in 2015. The DIR will end on May 31, 2015. Each January the costs in the DIR investments shall be reviewed for prudence by an independent auditor under the direction of Staff and funded by the Company. For any year that the revenue collected under the DIR is less than the annual cap allowance, as established above, then the difference between the revenue collected and the cap shall be applied to increase the level of the subsequent period's cap.

Q. PLEASE EXPLAIN WHY THE DIR INCLUDES NET ADDITIONS POST-2000?

A. The Company has not had a distribution base rate case to reflect these plant additions since the Commission first established unbundled distribution rates for the Companies in 2000.

Q. PLEASE DESCRIBE THE DIR MECHANISM.

A. Exhibit WAA-2 shows the methodology for calculating the revenue requirement for the DIR. In Case Nos. 05-842-EL-ATA and 05-843-EL-ATA, the Company received an increase in base distribution rates and offsetting decrease in transmission rates. The distribution revenue increase associated with these cases will be removed from the current distribution revenue requirement. Also deducted will be the revenue requirement related to distribution capital expenditures already established through the Enhanced Service Reliability Rider (ESRR). The net plant of the solar panels for both the Newark and Athens Distribution centers as well as the net plant for gridSMART® will be removed to reflect collection of these costs through other riders. The Company is proposing to update this rider quarterly based on the incremental increase in the net plant balance as shown on Form 3Q, which is filed quarterly with the Federal Energy Regulatory Commission (FERC). The adjustments associated with ESRR will be calculated annually, after the audit for the ESRR has taken place. The adjustment for the solar panels and gridSMART® assets will be updated quarterly with the DIR filing. This rider will be subject to over/under recovery. Because the costs are directly related to the Company's infrastructure, the rider will be collected as a percentage of base distribution revenue. The initial rate will be set in a separate proceeding before this Commission. Company witness Hamrock discusses benefits of the DIR.

STORM DAMAGE RECOVERY MECHANISM

Q. PLEASE EXPLAIN THE STORM DAMAGE RECOVERY MECHANISM?

A. Given the volatility of major storms and major storm damage restoration O&M expenses from year to year, the Company proposed that a Storm Damage Recovery mechanism be established. Consistent with the recommendation of Staff witness Hecker in Case Nos. 11-346-EL-SSO et al., the Stipulation includes such a mechanism (Paragraph IV.1.p, Page 11) with an annual baseline of $5.0 Million. This mechanism is necessary to preserve forecasted O&M for planned maintenance activities. If funds are constantly diverted to cover the expense of major storms, it could disrupt the completion of planned maintenance and ultimately have an impact on the reliability of the system. The Company will defer the actual expense above or below the baseline for future recovery or refund.

Q. WOULD THE STORM DAMAGE RECOVERY MECHANISM INCLUDE CAPITAL COSTS INCURRED AS A RESULT OF A MAJOR STORM?

A. No. Capital costs would become a component of the DIR or would be included in rate base in the next distribution rate case.

RPM SET-ASIDE ALLOTMENT RULES

Q. WHY WERE THE RPM SET-ASIDE ALLOTMENT RULES DEVELOPED?

A. In order to preserve and expand retail shopping in Ohio, the Company agreed to provide a fixed and annually increasing amount of its capacity to CRES providers serving retail load in Ohio at an RPM based price instead of a cost based price. The RPM Set Aside Allotment Rules were developed to provide a structured approach to assigning this discounted capacity. These rules are referenced in Paragraph IV.2.b and are provided in detail in Appendix C of the Stipulation.

Q. PARAGRAPH IV.2.B.3 (PAGE 21) STATES "IT IS THE CUSTOMER THAT RETAINS THE RIGHT TO THE RPM-PRICED CAPACITY IN THE EVENT THE CUSTOMER CHANGES FROM ONE CRES PROVIDER TO ANOTHER." CAN YOU EXPLAIN THE IMPORTANCE OF THIS STATEMENT?

A. Yes. This statement is very important to the development of a robust competitive market in Ohio and will help shopping customers receive a lower price and/or greater value than they would otherwise. Since a shopping customer retains the right to the RPM-priced capacity they can continue to shop for a better deal from competing CRES providers. If the right to this capacity were to revert to the CRES provider when a customer chose another CRES provider, customers would have a disincentive to switch providers and may ultimately result in higher prices for shopping customers.

Q. THE STIPULATION INCLUDES A PROVISION THAT THE RPM-PRICED CAPACITY SET-ASIDE "SHALL INITIALLY BE ALLOCATED ON A PRO RATA BASIS AMONG THE RESIDENTIAL, COMMERCIAL AND THE INDUSTRIAL CLASSES BASED UPON PROJECTED KWH CONSUMPTION FOR A PERIOD OF APPROXIMATELY 4 MONTHS

AFTER THE FILING OF THE STIPULATION." WHY IS THIS PROVISION IMPORTANT?

A. This provision will allow a broad spectrum of customers to benefit from this discounted capacity and allow shopping to develop in classes that have seen limited shopping to date. This provision will allow a greater variety of customers an opportunity to shop and CRES providers an opportunity to market to these customer classes. After this approximately four month transition period, all customers and customer classes will have access to this discounted capacity without regard to an allocation among the customer classes, within the confines of the RPM set-aside percentages.

Q. THE RPM SET-ASIDE RULES INCLUDE SEVERAL REFERENCES TO A "VALIDLY EXECUTED CONTRACT." PLEASE ELABORATE ON THE MEANING THIS PHRASE.

A. A validly executed contract is an agreement between the CRES and a customer for retail electric service.

Q. WOULD THIS INCLUDE A CONTRACT BETWEEN A CRES AND A GOVERNMENTAL AGGREGATION ENTITY?

A. No. This is not an agreement between a CRES and a customer. There are two types of governmental aggregation; opt-in and opt-out. In either case, there is no agreement between a CRES and a customer until the customer has opted-in to the governmental aggregation or has not opted-out of the governmental aggregation. The contract between the CRES and the customer would occur at the time that the customer opted-in or did not avail themselves of the opportunity to opt-out.

Q. THE RPM SET-ASIDE RULES INCLUDE SEVERAL REFERENCES TO A "SINGLE ELECTRIC BILLING METER." WHERE MULTIPLE METERS ARE USED AT THE SAME LOCATION TO BILL AN INDIVIDUAL CUSTOMER ARE THESE CONSIDERED SINGLE ELECTRIC BILLING METERS?

A. Yes. Where there is a logical billing location, referred to as an SDI, which is billed on a combined basis by AEP Ohio these multiple meters will be considered a single billing meter.

Q. HOW WILL UNMETERED LOADS BE ADDRESSED FOR PURPOSES OF THE RPM SET-ASIDE CAP?

A. A KWh allotment will be assigned to these loads consistent with the quantities specified in the tariffs or as specified in the contract.

Q. IF THERE ARE ELEMENTS OF THE RPM SET-ASIDE RULES THAT CRES PROVIDERS OR OTHER PARTIES FEEL ARE UNCLEAR IS THERE A PROCESS TO CLARIFY THE RULES?

A. Yes. As part of the Stipulation, the Signatory Parties have agreed to meet within two weeks of the filing of the Stipulation to develop a more detailed implementation plan. An initial meeting will occur by September 21, 2011.

<u>PHASE IN RECOVERY RIDER</u>

Q. PLEASE DISCUSS THE ELEMENTS OF THE STIPULATION RELATED TO THE PHASE IN RECOVERY RIDER.

A. The stipulation includes several provisions (Paragraph IV.6) that relate to the PIRR. Paragraph IV.6.A includes a provision that reduces the carrying charge applicable to the PIRR regulatory asset from the weighted average cost of capital (WACC) rate (11.15% as recently filed in Case Nos. 11-4920-EL-RDR and 11-4921-EL-RDR) previously approved by the Commission in Case Nos. 08-917-EL-SSO and 08-918-EL-SSO to a debt rate of 5.34%. Lowering the carrying charge rate from 11.15% to 5.34% reduces the carrying charges that customers are responsible for by $35.2 million in 2012 and by $153.4 million over the seven year recovery period (2012-2018).

Q. PARAGRAPH IV.6.b OF THE STIPULATION INCLUDES A PROVISION THAT DELAYS COLLECTION OF THE PIRR FROM RESIDENTIAL CUSTOMERS BY UP TO 12 MONTHS. HOW MUCH WILL RESIDENTIAL CUSTOMERS SAVE IN 2012 AS A RESULT OF THIS CHANGE?

A. The 12-month delay in the collection of the PIRR from residential customers will save residential customers approximately $34.4[1] million in 2012 or $2.32 per month for a typical customer using 1,000 kWh per month.

Q. IF THE PIRR REGULATORY ASSETS ARE NOT SECURITIZED, WILL THE DELAY IN THE COLLECTION OF THE PIRR HAVE AN IMPACT ON RESIDENTIAL CUSTOMERS IN 2013 THROUGH 2018?

A. Yes. Over the period 2013 through 2018 a typical residential customer would see total increased costs of $10.68 ($1.78 annually[2]) compared to total savings of $27.84 in 2012.

[1] $2.32/MWh * 14,831 GWh = $34.4 million
[2] ($2.469/MWh – $2.321/MWh) * 12 MWh/yr = $1.78/yr

Q. IF THE PIRR REGULATORY ASSETS ARE NOT SECURITIZED, WILL THE DELAY IN THE COLLECTION OF THE PIRR FROM RESIDENTIAL CUSTOMERS HAVE AN IMPACT ON NON-RESIDENTIAL CUSTOMERS IN 2013 THROUGH 2018?

A. Yes, the delay in collection of the PIRR from residential customers would result in a small increase in the PIRR that all customers would see over the period 2013 through 2018, approximately $0.143 per MWh[3].

<u>SECURITIZATION OF PIRR REGULATORY ASSETS</u>

Q. PARAGRAPH IV.6.C OF THE STIPULATION STATES "ONCE SECURITIZATION IS COMPLETED, ALL CUSTOMERS WILL BENEFIT FROM LOWER PIRR CHARGES FROM THAT POINT GOING FORWARD." HAVE YOU ESTIMATED THE SAVINGS THAT WOULD RESULT FROM SECURITIZATION OF THE PIRR REGULATORY ASSETS?

A. Yes. Without securitization the PIRR would be $2.38 per MWh from 2013 through 2018 and with securitization that rate would drop to $1.13 per MWh from 2013 through 2025. The net present value of the customer payments without securitization would be $532 million and the net present value of the customer payments with securitization would be $460 million resulting in a savings of $72 million. The securitization model, including assumptions and cash flows, is provided as Exhibit WAA-3.

[3] $2.380/MWh - $2.237/MWh = $0.143/MWh

	With Securitization	Without Securitization
Rate	$1.13/MWh	$2.38/MWh
Net Present Value	$460M	$532M

QUANTIFICATION OF ESP BENEFITS

Q. HAVE YOU REVIEWED THE ESP VERSUS MRO PRICE TEST THAT COMPANY WITNESS THOMAS PRESENTED IN HER TESTIMONY?

A. Yes. Company witness Thomas has developed a comparison of the prices that non-shopping customers would pay under the ESP pricing provisions included in the Stipulation and the expected prices under an MRO. Based on the assumption that 79%, 69% and 59% of the load in 2012, 2013 and 2014/15[4], respectively, of AEP Ohio chooses not to shop and takes service under SSO rates, this results in a savings of $151 million over the first 41 months of the ESP (including the 2012 net MTR charge of $24M), $130 million on a net present value (NPV) basis. This analysis is presented in Exhibit WAA-4.

Q. IS THIS THE ONLY QUANTIFIABLE BENEFIT OF THE ESP?

A. No, it is not. There are several other benefits that customers will receive under the ESP that would not be expected to occur under an MRO.

Q. PLEASE IDENTIFY THOSE ADDITIONAL BENEFITS.

A. As part of this ESP AEP Ohio is providing capacity to CRES providers at a significant discount than would be expected under an MRO. As I have previously discussed, AEP Ohio has agreed to reduce the carrying costs on the PIRR regulatory assets from the WACC rate previously approved by the Commission

[4] January 1, 2014 through May 31, 2015.

in Case Nos. 08-917-EL-SSO and 08-918-EL-SSO to a debt rate of 5.34%. AEP Ohio has also agreed not to seek recovery from customers of generation-related costs associated with implementing corporate separation (Paragraph IV.1.q, Page 11). In addition, AEP Ohio has agreed to provide funding for the Partnership With Ohio (PWO) initiative of $3 million annually and the Ohio Growth Fund (OGF) initiative of $5 million annually during the term of the ESP.

Q. HAVE YOU ESTIMATED THE VALUE OF THESE ADDITIONAL BENEFITS?

A. Yes, I have estimated the net present value (NPV) of each of these benefits. As shown in Exhibit WAA-4, the NPV benefit of the discounted capacity provided to CRES is $856 million, the NPV benefit of the reduced PIRR carrying cost rate is $104 million, and the NPV benefit of the PWO and OGF initiatives is $27 million. The total NPV benefit of the ESP versus the expected result under an MRO is $1,118 million.

Q. CAN YOU QUANTIFY THE POTENTIAL BENEFIT OF THE SEET ROE THRESHOLD INCLUDED IN PARAGRAPH IV.1.g (PAGE 7) OF THE STIPULATION?

A. Yes. In the Opinion and Order in Case No. 10-1261-EL-UNC, the Commission determined that a SEET threshold of 17.6% was appropriate. Applying the 4.1% difference in the SEET threshold approved in that case and the threshold agreed to in the Stipulation to the expected 2015 equity balance could result in added customer protection of approximately $120 million.

PRO FORMA FINANCIALS

Q. HAVE YOU OR SOMEONE UNDER YOUR SUPERVISION PREPARED *PRO FORMA* FINANCIAL PROJECTIONS REFLECTING THE STIPULATION?

A. Yes, attached to my testimony as Exhibit WAA-5 are an income statement, balance sheet and cash flow for the Company showing the effect of the ESP Stipulation's implementation upon the Company for the duration of the proposed ESP. These projections include an assumption that corporate separation is completed January 1, 2013. The exhibit provides the list of assumptions that were used to prepare the financial statements. I have also included in this exhibit the methodology used in deriving the pro forma projections.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes it does.

INFORMATION PROVIDED PURSUANT TO OAC 4901:1-35-03(C)(9)(a)

General Fuel Requirements

The generating units of CSP and OPCo (AEP Ohio) and the other AEP System- East Zone operating companies, which are predominantly coal-fired, are managed to ensure adequate fuel supplies to meet normal burn requirements in both the short-term and the long-term. American Electric Power Service Corporation (AEPSC), acting as agent for AEP Ohio, is responsible for the procurement and delivery of fuel and chemicals used for environmental compliance (consumables) to AEP Ohio's generating stations. AEPSC's primary objective is to assure a continuous supply of quality fuel at the lowest cost reasonably possible. Deliveries are arranged so that sufficient fuel and consumables are available at all times. The quality of the delivered coal is fundamental to achieving and maintaining compliance with the applicable environmental limitations and operating efficiencies.

AEP Ohio proposes to pass any net gains on the sale of emission allowances through the FAC. AEP does not have a practice of re-selling coal contracts, however, if it did so it would pass any cost savings or profits related to Ohio generating resources through the FAC.

Coal and Gas Procurement Process

Coal delivery requirements are determined by taking into account existing coal inventory, forecasted coal consumption, and adjustments for contingencies that necessitate an increase or decrease in coal inventory levels. Sources of coal are determined by taking into account contractual obligations and existing sources of supply.

INFORMATION PROVIDED PURSUANT TO OAC 4901:1-35-03(C)(9)(a)

AEP Ohio's total coal requirements are met using a portfolio of long-term arrangements and spot-market purchases. Long-term contracts support a relatively stable and consistent supply of coal. Spot purchases are used to provide flexibility in scheduling contract deliveries, to accommodate changing demand, and to cover shortfalls in deliveries caused by force majeure and other unforeseeable or unexpected circumstances. Occasionally, spot purchases are also made to test-burn any promising and potential new long-term sources of fuel in order to determine their acceptability as a fuel source in a given power plant's generating units.

All long-term and most spot purchases of coal for AEP Ohio's plants are made based on the evaluation of competitive bids. Additional short-term purchases are made based on an evaluation of offers (both solicited and unsolicited) from suppliers compared to current published market prices as well as other offers for tonnage of acceptable quality. In all cases, the goal is securing the lowest reasonable delivered price on a cents-per-million-BTU basis.

AEP Ohio's day-to-day needs for natural gas are generally unpredictable and are generally purchased on a day-ahead and intra-day basis as needed for peaking requirements. Natural gas is competitively purchased and primarily obtained in the spot market with prices on a daily index or a daily fixed price. The Company has arranged for both firm and interruptible transportation service from various inter-state pipelines, which provide flexible supplies from multiple production areas.

Inventory

AEP Ohio attempts to maintain in storage at each plant an adequate coal and consumables

INFORMATION PROVIDED PURSUANT TO OAC 4901:1-35-03(C)(9)(a)

supply to meet normal burn requirements. However, in situations where coal supplies fall below prescribed minimum levels, the Company attempts to conserve coal supplies. In the event of a severe coal shortage, AEP Ohio and the AEP System-East Zone operating companies would implement procedures for the orderly reduction of the consumption of electricity, in accordance with the Emergency Operating Plan.

Generating Unit Information

The generating units that AEP Ohio owns are included in the table below. The table also lists major environmental equipment that has been added to the units: Flue Gas Desulfurization (FGD) for the control of SO_2 emissions, and Selective Catalytic Reduction (SCR) for the control of NO_X emissions. The costs associated with these generating units are included in the FAC as set out in the Company's testimony in its ESP filing.

INFORMATION PROVIDED PURSUANT TO OAC 4901:1-35-03(C)(9)(a)

AEP System - AEP Ohio
Existing Generation Capacity as of June 1, 2010

Plant Name	Unit No.	In-Service Date		Fuel Type	SCR Installation Year	FGD Installation Year
		CSP				
Beckjord	6	1969		Coal	--	--
Conesville	3	1962		Coal	--	--
Conesville	4	1973		Coal	2009	2009
Conesville	5	1976		Coal	2015	1976
Conesville	6	1978		Coal	2015	1978
Picway	5	1955		Coal	--	--
Stuart	1	1971		Coal	2004	2008
Stuart	2	1970		Coal	2004	2008
Stuart	3	1972		Coal	2004	2008
Stuart	4	1974		Coal	2004	2008
Zimmer	1	1991		Coal	2004	1991
Waterford	1-6	2002	(a)	Gas (CC)	2002	--
Darby	1-6	2002	(d)	Gas (CT)	2002	--
Lawrenceburg	1-6	2004	(d)	Gas (CC)	--	--
Stuart Diesel	1-4	1969		Oil (Diesel)	--	--
		OPCo				
Amos	3	1973		Coal	2004	2009
Cardinal	1	1967		Coal	2004	2008
Gavin	1	1974		Coal	2004	1994
Gavin	2	1975		Coal	2004	1994
Kammer	1	1958		Coal	--	--
Kammer	2	1958		Coal	--	--
Kammer	3	1959		Coal	--	--
Mitchell	1	1971		Coal	2007	2007
Mitchell	2	1971		Coal	2007	2007
Muskingum River	1	1953		Coal	--	--
Muskingum River	2	1954		Coal	--	--
Muskingum River	3	1957		Coal	--	--
Muskingum River	4	1958		Coal	--	--
Muskingum River	5	1968		Coal	2005	2015
Sporn	2	1950		Coal	--	--
Sporn	4	1952		Coal	--	--
Sporn	5	1960		Coal	--	--
OPCo Hydro		1983	(b)	Hydro	--	--

(a) Acquired in 2005
(b) Racine Hydro
(d) Acquired in 2007 by AEP Generating Co, CSP receives capacity and energy via agreement

INFORMATION PROVIDED PURSUANT TO OAC 4901:1-35-03(C)(9)(a)

Purchased Power

AEP Ohio makes power purchases from affiliates, non-affiliated companies and through the PJM market that will be included in the Companies' proposed FAC. AEP Ohio has contracts to purchase power from OVEC and Buckeye Power generating units, and from its affiliate, American Electric Generating Company's (AEG) Lawrenceburg plant.

AEP Power Pool and PJM

The 2009 FAC reflects the AEP Ohio generating resources being operated under the AEP Interconnection Agreement. AEP is a member of PJM and operates its fleet, including AEP Ohio's generating resources, in accordance with PJM protocols.

Economic Dispatch

AEP, along with other generators in PJM, "offer(s)" available generating units into the PJM market on a daily basis. PJM performs an economic dispatch for the PJM footprint to meet the load requirements with all available generation. After the end of the month AEP reconstructs, for cost allocation purposes, the economic dispatch for its units based on hourly generating unit output. This reconstruction assigns the resources used for Off-System Sales for each hour of the month. The resources at the top of the stack, i.e., those with higher variable costs, are assigned to Off-System Sales resulting in lower costs assigned to internal load customers.

AEP Ohio Proposed Distribution Investment Rider

Line		CSP	OPCo	AEP Ohio
1	2000 Distribution Net Plant			
2	Distribution Plant - Form 1 Page 207 Line 69	$ 1,094,289,026	$ 1,040,916,689	$ 2,135,205,715
3	Accumulated Depreciation - Form 1 Page 219 Line 24	$ 451,885,982	$ 309,699,840	$ 761,585,822
4=2-3	Net Distribution Plant	$ 642,403,044	$ 731,216,849	$ 1,373,619,893
5				
6	20XX Distribution Net Plant			
7	Distribution Plant - Form 1 Page 207 Line XX	TBD	TBD	TBD
8	Accumulated Depreciation - Form 1 Page 219 Line XX	TBD	TBD	TBD
9=7-8	Net Distribution Plant			
10				
11=9-4	Change in Distribution Net Plant			
12				
13	Solar Panel Net Plant Adjustment (Recovered through FAC)			
14				
15	gridSMART Net Plant Adjustment (Recovered through GS Rider)			
16				
17=11-13-15	Adjusted Distribution Net Plant			
18				
19	Carrying Charge Rate (See Page 2 of Exhibit WAA-1)			
20				
21=17*19	Rider Revenue			
22				
23	2006 Distribution Increase Case Nos. 05-842 & 05-843	$ 7,976,901	$ 11,907,391	$ 19,884,292
24				
25=21-23	Revised Rider Revenue			
26				
27	Capital Revenue Requirement for Veg Mgmt			
28				
29=25-27	Fully Adjusted Rider Revenue			
30				
31	Annual Base Distribution Revenue			
32				
33=29/31	AEP Ohio Percentage of Base Distribution Rate			%

AEP Ohio Proposed Distribution Investment Rider Carrying Charge Calculation

Calculation of Pre-Tax WACC Rate

Line #	Capital	Face Amount Outstanding	Percentage of Total Captial	Embedded Cost	Pre-tax WACC
1	Long-Term Debt	4,177,325,000	47.06%	5.34%	2.51%
2	Preferred Stock	16,625,800	0.19%	4.40%	0.01%
3	Common Stock	4,682,891,283	52.75%	10.50%	8.71%
4	**Total Pre-Tax WACC**	**8,876,842,083**	**100.00%**		**11.23%**

Calculation of Property and CAT Tax Rates

Line #		CSP Calc's	CSP Rate	Filing/Calc Reference
	Property Tax Expense			
5	Property Tax Expense	70,758,000		Vol. 1, Sch C-2.1 p 5, Ln 8, Col (F)
6	Gross Plant	1,853,590,000		Vol. 1, Sch B-2, Lns 3&4, Col (E)
7	Accum Depr	(772,540,000)		Vol. 1, Sch B-3, pg 2, Ln 16, (Col (I); & pg 3, Ln 14, Col (I).
8	Net Plant	1,081,050,000		Ln 6 - Ln 7
9	Property Tax Rate		6.55%	Ln 5 / Ln 8
10	CAT Tax Expense (Statutory Rate)		0.260%	Sch A-2, Ln 5, Col (C)
11	CSP Tax Carrying Rate Subtotal		6.805%	Ln 9 + Ln 10

Line #		OPCo Calc's	OPCo Rate	Filing/Calc Reference
	Property Tax Expense Rate			
12	Property Tax Expense	54,682,000		Vol. 2, Sch C-2.1 p 5, Ln 8, Col (F)
13	Gross Plant	1,707,371,000		Vol. 2, Sch B-2, Lns 3&4, Col (E)
14	Accum Depr	(570,888,000)		Vol. 2, Sch B-3, pg 2, Ln 16, (Col (I); & pg 3, Ln 14, Col (I).
15	Net Plant	1,136,483,000		Ln 13 - Ln 14
16			4.81%	Ln 12 / Ln 15
17	CAT Tax Expense (Statutory Rate)		0.260%	Vol. 2, Sch A-2, Ln 5, Col (C)
18	OPCo Tax Carrying Rate Subtotal		5.072%	Ln 16 + Ln 17

Weighted Average AEP Ohio Tax Carrying Rate Calculation

Line #		Rate	Filing/Calc Reference
19	AEP Ohio Weighted Property Tax Rate	5.66%	(Lns 5 + 12) / (Lns 8 + 15)
20	CAT Tax Expense (Statutory Rate)	0.260%	Sch A-2, Ln 5
21	**AEP Ohio Weighted Average Carrying Tax Rate**	**5.917%**	Ln 19 + Ln 20
22	**AEP Ohio Average Depreciation Rate**		Per Distribution Rates in Case Nos. 11-351-EL-AIR & 11-351-EL-AIR
23	**AEP Ohio Carrying Charge Rate**		**Ln 4 + Ln 21 + Ln 22**

SECURITIZATION MODEL

Assumptions

Amount to Securitize	$ 587,000
Issuance Date	1/1/2013
Securitization Rate ($/MWh)	1.1322
Annual Load Growth	0.50%

Tranche	Principal Amount	Scheduled Final Payment Date	No. of Semi-Annual Principal Payments	Interest Rate
A-1	$ 145,000	7/1/2016	7	1.28%
A-2	$ 133,000	7/1/2019	6	2.01%
A-3	$ 146,000	7/1/2022	6	3.08%
A-4	$ 163,000	7/1/2025	6	3.28%
	$ 587,000		25	

Check	$ -

SECURITIZATION MODEL

Expected Sinking Fund Schedule

Semi-Annual Payment Date	Tranche A-1 Balance	Tranche A-2 Balance	Tranche A-3 Balance	Tranche A-4 Balance	Total
Tranche Size	$ 145,000	$ 133,000	$ 146,000	$ 163,000	$ 587,000
7/1/2013	$ 20,075				$ 20,075
1/1/2014	$ 20,272				$ 20,272
7/1/2014	$ 20,470				$ 20,470
1/1/2015	$ 20,669				$ 20,669
7/1/2015	$ 20,870				$ 20,870
1/1/2016	$ 21,073				$ 21,073
7/1/2016	$ 21,572	$ (295)			$ 21,276
1/1/2017		$ 21,481			$ 21,481
7/1/2017		$ 21,766			$ 21,766
1/1/2018		$ 22,054			$ 22,054
7/1/2018		$ 22,346			$ 22,346
1/1/2019		$ 22,640			$ 22,640
7/1/2019		$ 23,008	$ (71)		$ 22,938
1/1/2020			$ 23,238		$ 23,238
7/1/2020			$ 23,666		$ 23,666
1/1/2021			$ 24,101		$ 24,101
7/1/2021			$ 24,543		$ 24,543
1/1/2022			$ 24,992		$ 24,992
7/1/2022			$ 25,530	$ (82)	$ 25,448
1/1/2023				$ 25,911	$ 25,911
7/1/2023				$ 26,408	$ 26,408
1/1/2024				$ 26,912	$ 26,912
7/1/2024				$ 27,426	$ 27,426
1/1/2025				$ 27,947	$ 27,947
7/1/2025				$ 28,478	$ 28,478
Total Payments	$ 145,000	$ 133,000	$ 146,000	$ 163,000	$ 587,000

SECURITIZATION MODEL

Interest Payments

Semi-Annual Payment Date	Tranche A-1 Balance	Tranche A-2 Balance	Tranche A-3 Balance	Tranche A-4 Balance	Total
7/1/2013	$ 928	$ 1,337	$ 2,248	$ 2,673	$ 7,186
1/1/2014	$ 800	$ 1,337	$ 2,248	$ 2,673	$ 7,058
7/1/2014	$ 670	$ 1,337	$ 2,248	$ 2,673	$ 6,928
1/1/2015	$ 539	$ 1,337	$ 2,248	$ 2,673	$ 6,797
7/1/2015	$ 406	$ 1,337	$ 2,248	$ 2,673	$ 6,665
1/1/2016	$ 273	$ 1,337	$ 2,248	$ 2,673	$ 6,531
7/1/2016	$ 138	$ 1,337	$ 2,248	$ 2,673	$ 6,396
1/1/2017	$ -	$ 1,340	$ 2,248	$ 2,673	$ 6,261
7/1/2017	$ -	$ 1,124	$ 2,248	$ 2,673	$ 6,045
1/1/2018	$ -	$ 905	$ 2,248	$ 2,673	$ 5,827
7/1/2018	$ -	$ 683	$ 2,248	$ 2,673	$ 5,605
1/1/2019	$ -	$ 459	$ 2,248	$ 2,673	$ 5,380
7/1/2019	$ -	$ 231	$ 2,248	$ 2,673	$ 5,153
1/1/2020	$ -	$ -	$ 2,249	$ 2,673	$ 4,923
7/1/2020	$ -	$ -	$ 1,892	$ 2,673	$ 4,565
1/1/2021	$ -	$ -	$ 1,527	$ 2,673	$ 4,200
7/1/2021	$ -	$ -	$ 1,156	$ 2,673	$ 3,829
1/1/2022	$ -	$ -	$ 778	$ 2,673	$ 3,451
7/1/2022	$ -	$ -	$ 393	$ 2,673	$ 3,066
1/1/2023	$ -	$ -	$ -	$ 2,675	$ 2,675
7/1/2023	$ -	$ -	$ -	$ 2,250	$ 2,250
1/1/2024	$ -	$ -	$ -	$ 1,817	$ 1,817
7/1/2024	$ -	$ -	$ -	$ 1,375	$ 1,375
1/1/2025	$ -	$ -	$ -	$ 925	$ 925
7/1/2025	$ -	$ -	$ -	$ 467	$ 467
Total Payments	$ 3,754	$ 14,098	$ 37,225	$ 60,299	$ 115,375

SECURITIZATION MODEL

Expected Amortization Schedule

Semi-Annual Payment Date	Tranche A-1 Balance	Tranche A-2 Balance	Tranche A-3 Balance	Tranche A-4 Balance	Total
	$ 145,000	$ 133,000	$ 146,000	$ 163,000	$ 587,000
7/1/2013	$ 124,925	$ 133,000	$ 146,000	$ 163,000	$ 566,925
1/1/2014	$ 104,653	$ 133,000	$ 146,000	$ 163,000	$ 546,653
7/1/2014	$ 84,184	$ 133,000	$ 146,000	$ 163,000	$ 526,184
1/1/2015	$ 63,514	$ 133,000	$ 146,000	$ 163,000	$ 505,514
7/1/2015	$ 42,644	$ 133,000	$ 146,000	$ 163,000	$ 484,644
1/1/2016	$ 21,572	$ 133,000	$ 146,000	$ 163,000	$ 463,572
7/1/2016	$ -	$ 133,295	$ 146,000	$ 163,000	$ 442,295
1/1/2017	$ -	$ 111,814	$ 146,000	$ 163,000	$ 420,814
7/1/2017	$ -	$ 90,048	$ 146,000	$ 163,000	$ 399,048
1/1/2018	$ -	$ 67,994	$ 146,000	$ 163,000	$ 376,994
7/1/2018	$ -	$ 45,649	$ 146,000	$ 163,000	$ 354,649
1/1/2019	$ -	$ 23,008	$ 146,000	$ 163,000	$ 332,008
7/1/2019	$ -	$ -	$ 146,071	$ 163,000	$ 309,071
1/1/2020	$ -	$ -	$ 122,833	$ 163,000	$ 285,833
7/1/2020	$ -	$ -	$ 99,167	$ 163,000	$ 262,167
1/1/2021	$ -	$ -	$ 75,065	$ 163,000	$ 238,065
7/1/2021	$ -	$ -	$ 50,522	$ 163,000	$ 213,522
1/1/2022	$ -	$ -	$ 25,530	$ 163,000	$ 188,530
7/1/2022	$ -	$ -	$ -	$ 163,082	$ 163,082
1/1/2023	$ -	$ -	$ -	$ 137,171	$ 137,171
7/1/2023	$ -	$ -	$ -	$ 110,763	$ 110,763
1/1/2024	$ -	$ -	$ -	$ 83,851	$ 83,851
7/1/2024	$ -	$ -	$ -	$ 56,425	$ 56,425
1/1/2025	$ -	$ -	$ -	$ 28,478	$ 28,478
7/1/2025	$ -	$ -	$ -	$ 0	$ 0

SECURITIZATION MODEL

Revenue/Expense Comparison

Semi-Annual Payment Date	Forecasted Sales (GWh)	Securitization Rate ($/MWh)	Securitization Revenues	Securitization Expense
7/1/2013	24,079	1.1322	27,261	$ 27,261
1/1/2014	24,139	1.1322	27,329	$ 27,329
7/1/2014	24,199	1.1322	27,398	$ 27,398
1/1/2015	24,260	1.1322	27,466	$ 27,466
7/1/2015	24,320	1.1322	27,535	$ 27,535
1/1/2016	24,381	1.1322	27,604	$ 27,604
7/1/2016	24,442	1.1322	27,673	$ 27,673
1/1/2017	24,503	1.1322	27,742	$ 27,742
7/1/2017	24,564	1.1322	27,811	$ 27,811
1/1/2018	24,626	1.1322	27,881	$ 27,881
7/1/2018	24,687	1.1322	27,951	$ 27,951
1/1/2019	24,749	1.1322	28,020	$ 28,020
7/1/2019	24,811	1.1322	28,090	$ 28,090
1/1/2020	24,873	1.1322	28,161	$ 28,161
7/1/2020	24,935	1.1322	28,231	$ 28,231
1/1/2021	24,997	1.1322	28,302	$ 28,302
7/1/2021	25,060	1.1322	28,372	$ 28,372
1/1/2022	25,123	1.1322	28,443	$ 28,443
7/1/2022	25,185	1.1322	28,514	$ 28,514
1/1/2023	25,248	1.1322	28,586	$ 28,586
7/1/2023	25,311	1.1322	28,657	$ 28,657
1/1/2024	25,375	1.1322	28,729	$ 28,729
7/1/2024	25,438	1.1322	28,801	$ 28,801
1/1/2025	25,502	1.1322	28,873	$ 28,873
7/1/2025	25,566	1.1322	28,945	$ 28,945
			$ 702,375	$ 702,375
			NPV @ 1-2012	$ 459,777

Quantifiable Benefits of the ESP

	NPV @ 6%	2012	2013	2014	2015	2016	2017	2018
ESP Price Benefit for Non-Shopping Customers	$130 M	$21 M	$41 M	$51 M	$38 M			
Value of Discounted Capacity Provided to CRES Providers	$856 M	$196 M	$332 M	$342 M	$112 M			
Reduced PIRR Carrying Costs	$104 M	$35 M	$32 M	$28 M	$24 M	$18 M	$12 M	$4 M
Partnership With Ohio Initiative	$10 M	$3 M	$3 M	$3 M	$3 M	$1 M		
Ohio Growth Fund Initiative	$17 M	$5 M	$5 M	$5 M	$5 M	$2 M		
Total Quantifiable ESP Benefits	$1,118 M	$260 M	$413 M	$429 M	$182 M	$22 M	$12 M	$4 M

Methodology, Assumptions and
Pro Forma Financial Projections

Methodology

The Pro Forma financial statements were developed consistent with the methodology utilized by the Company for preparing its normal operating forecast. This methodology is a process requiring input from a variety of groups within AEP and AEP Ohio. Due to the integrated nature of the AEP System, the preparation of any individual operating company forecast requires a forecast of the entire AEP System. The major components of a forecast are as follows: 1) load and demand forecast; 2) generation forecast; 3) retail and firm wholesale operating revenue projections; 4) O&M forecast; 5) construction expenditure forecast; and 6) financing plan. The Pro Formas also reflect the financial effect of the Company's proposed ESP plan.

Assumptions, such as growth in kilowatt-hour sales, fuel expense, interest rates, and cost projections based on each of the companies' work plans, are made in advance of the preparation of the forecast. These assumptions are reviewed with individuals from the operating companies and within AEPSC to determine the most reasonable set of assumptions to be incorporated into the forecast. As we progress through each year's business we track and monitor actual performance compared to plan and adjust the plans as necessary. The major sequential steps are as follows:

1) Load and Demand Forecast - Because the AEP System is highly integrated, the preparation of any individual company forecast requires an internal load forecast and an off-system sales forecast for all the AEP System companies.

Methodology, Assumptions and
Pro Forma Financial Projections

The internal load projection is developed by the Financial and Economic Forecasting Department in conjunction with various groups across the AEP System including input from the operating companies and reflects an analysis of the economy and the unique factors that influence individual customers or customer classes in each of the regions that AEP serves.

2) Generation Forecast - A generation forecast is developed by the Commercial Operations Division and the Resource Planning and Operational Analysis Department which, together with planned energy purchases, is sufficient to meet the system's anticipated total energy requirements. The cost of fuel consumed is based on the generation forecast for each of the generating units in the AEP System. In addition to fuel costs, AEP incurs other variable costs of production, costs for other consumable materials at our generating stations for the operation of environmental equipment and purchased power costs.

3) Retail and Wholesale Operating Revenue Projections - Revenues for most customers are developed by customer class using base realizations under current rates and fuel adjustment clauses included in the appropriate filed tariffs or contracts. Projections of base realizations reflect actual experience adjusted to be consistent with the projected sales and usage levels. Revenues for large wholesale and other special contract customers are developed in detail in accordance with the terms of the contract, including demand, energy and fuel adjustment charges. Revenues related to known off-system sales arrangements are developed in

Methodology, Assumptions and
Pro Forma Financial Projections

accordance with the terms of the specific agreements related to such sales. The bulk of the projected off-system sales volume sold to counter-parties is not known when the forecast is developed and, therefore, is priced at expected market rates.

5) O&M Forecast – Operation and maintenance expenses, excluding energy costs, are based upon current work plans for each of the functional groups. These plans include expenditures for scheduled maintenance programs as well as the cost of operations. These plans take into consideration staffing levels, including budgeted increases in salaries as well as material costs necessary to perform each planned program. While this data is developed for both OPCo and CSP individually, the review process generally looks at the two companies combined since they are effectively operating as one.

6) Construction Expenditure Forecast - The various engineering and planning groups in each operating company and in the AEP Service Corporation develop the construction expenditure budget. It reflects expenditures and in-service dates of major projects during the year as well as amounts approved to fund blanket work (smaller projects grouped together) which is essential in estimating both book and tax depreciation as well as the allowance for funds used during construction (AFUDC).

7) Financing Plan - The development of the financing program for the forecast is intended to meet the company's working capital requirements. In determining the company's financing program, consideration is given to coverage

and other regulatory restrictions, timing of requirements, availability of equity capital, and corporate objectives such as credit metrics, capital structure and short-term debt limitations.

Methodology, Assumptions and
Pro Forma Financial Projections

Assumptions

- Utility Operations sells generation beyond the system internal load requirements into the wholesale market.
- The assumed load forecast (including Ohio Customer Choice) is provided below:

Connected Load Data by Customer Class (GWh)					
	2012	2013	2014	2015	2016
Residential	14,701	14,690	14,686	14,628	14,598
Commercial	14,260	14,392	14,418	14,407	14,449
Industrial	19,158	19,408	19,290	19,077	18,962
Other Retail	128	127	127	127	127
Total Retail	**48,247**	**48,617**	**48,522**	**48,239**	**48,135**

- All financially significant components of the Company's ESP filing are included in these projections.
- Long-term interest rates are assumed to be 6.0% for all new issuances.
- Current depreciation rates were assumed to continue through the forecast period.
- No attempt has been made to show all transactions necessary to reflect the proposed merger. The projected financial statements reflect an addition of the forecasted results for the two companies with the exception that Interconnection Agreement capacity payments were eliminated from CSP.
- The Phase-In deferred fuel balance is securitized effective January 1, 2013.
- Corporate Separation is completed by January 1, 2013.
- FRR CRES capacity charges are based on the rates included in the Stipulation.

Methodology, Assumptions and
Pro Forma Financial Projections

Pro Forma Financials

INCOME STATEMENT
($000,000)

Line		2012	2013	2014	2015	2016
(1)	**Combined AEP Ohio***					
(2)	**REVENUE**					
(3)	Sales of Electricity	4,971,353	3,403,115	3,164,577	2,418,709	1,876,860
(4)	Other Operating Revenue	128,900	219,362	266,747	377,198	454,849
(5)	Total Revenue	5,100,253	3,622,477	3,431,324	2,795,908	2,331,710
(6)	**COST OF SALES**					
(7)	Total Cost of Sales	2,312,209	1,985,609	1,743,033	1,064,635	580,513
(8)	Gross Margin	2,788,044	1,636,868	1,688,291	1,731,272	1,751,197
(9)	**OPERATING EXPENSES**					
(10)	Operations & Maintenance	1,117,074	630,360	659,240	703,167	732,330
(11)	Taxes Other Than Income	398,423	349,617	357,604	362,944	368,683
(12)	TOTAL OPERATING EXPENSES	1,515,497	979,976	1,016,843	1,066,111	1,101,014
(13)	Operating Margin/EBITDA	1,272,547	656,892	671,448	665,162	650,183
(14)	Depreciation & Amortization	580,106	258,818	262,534	265,143	267,195
(15)	Other (Income) / Deductions	(58,149)	(19,007)	(19,577)	(20,165)	(20,770)
(16)	EBIT	750,590	417,081	428,491	420,183	403,758
(17)	Total Interest Expense	213,390	117,816	119,316	120,816	122,316
(18)	Total Income Taxes	182,494	103,246	106,666	103,282	97,098
(19)	Preferred Stock Dividends	889	391	391	391	391
(20)	**NET INCOME**	**353,817**	**195,628**	**202,119**	**195,695**	**183,954**
(21)	**RETURN ON COMMON EXCLUDING OSS**	7.71%	10.78%	11.00%	10.51%	9.80%

* **Excludes OSS**

Methodology, Assumptions and Pro Forma Financial Projections

BALANCE SHEET
($000)

Line		2012	2013	2014	2015	2016
(1)	**Combined AEP Ohio***					
(2)	**Assets**					
(3)	Gross Plant in Service	15,827,029	6,126,489	6,347,607	6,499,460	6,622,547
(4)	Construction Work In Progress	381,231	220,566	228,201	265,275	341,342
(5)	Gross Plant in Service	16,208,260	6,347,055	6,575,808	6,764,735	6,963,888
(6)	Accumulated Depreciation	6,339,071	2,447,724	2,543,362	2,643,285	2,746,782
(7)	Net Utility Plant	9,869,189	3,899,331	4,032,447	4,121,450	4,217,106
(8)	Other Property and Investments	180,548	18,608	18,608	18,608	18,608
(9)	Current and Accrued Assets	1,245,131	844,555	844,555	844,555	844,555
(10)	Unamortized Debt Expense	16,330				
(11)	Unamortized Loss on Reacquired Debt	13,952	46,213	39,897	33,582	27,266
(12)	Regulatory Assets	1,314,931	731,989	670,381	612,398	557,446
(13)	Other Net Deferrals	673,233	207,469	207,469	207,469	207,469
(14)	Total Assets	13,313,314	5,748,165	5,813,357	5,838,061	5,872,450
(15)	**Equity and Liabilities**					
(16)	Common Stock	4,693,028	1,820,628	1,847,747	1,868,442	1,877,396
(17)	Preferred Stock	16,616	8,871	8,871	8,871	8,871
(18)	Other Comprehensive Earnings	(168,368)	3,896	3,896	3,896	3,896
(19)	Total Equity	4,541,276	1,833,395	1,860,514	1,881,209	1,890,163
(20)	Long-Term Debt	3,860,430	1,825,000	1,850,000	1,875,000	1,900,000
(21)	Capital Leases	43,515	18,112	18,112	18,112	18,112
(22)	Other Non-Current Liabilities	621,525	187,144	187,144	187,144	187,144
(23)	Short-Term Debt		14,995	28,068	7,077	7,512
(24)	Other Current and Accrued Liabilities	1,286,351	879,461	879,461	879,461	879,461
(25)	Deferred Credits	2,960,216	990,058	990,058	990,058	990,058
(26)	Total Equity and Liabilities	13,313,314	5,748,165	5,813,357	5,838,061	5,872,450
(27)	Total Debt/Capital	46.2%	50.1%	50.2%	50.0%	50.2%

* **Excludes OSS**

Methodology, Assumptions and Pro Forma Financial Projections

CASH FLOW
($000)

Line		2012	2013	2014	2015	2016
(1)	**Combined AEP Ohio***					
(2)	**Operating Activities**					
(3)	Balance for Common	354,706	195,628	202,119	195,695	183,954
(4)	**Adjustments to Net Income**					
(5)	Depreciation and Amortization	580,106	194,870	200,926	207,160	212,243
(6)	Deferred Income Tax	19,141				
(7)	Changes in Regulatory Assets	(17,414)	63,948	61,608	57,983	54,952
(8)	Changes in Working Capital	188,827				
(9)	Other Adjustments to Net Income	79,038	6,316	6,316	6,316	6,316
(10)	**Cash From Operations**	1,204,404	460,762	470,969	467,154	457,465
(11)	**Investing Activities**					
(12)	Construction Expenditues	(597,033)	(321,095)	(322,750)	(282,474)	(288,314)
(13)	AFUDC Debt/Capitalized Interest	(12,166)	(14,997)	(11,292)	(13,689)	(19,585)
(14)	**Cash Used in Investing**	(609,199)	(336,092)	(334,041)	(296,163)	(307,899)
(15)	**Financing Activities**					
(16)	Issuance of Long-Term Debt		50,000	25,000	25,000	25,000
(17)	Retirement of Long-Term Debt	(194,500)				
(18)	Change in Short-Term Debt		331	13,072	(20,990)	435
(19)	Equity Contributions					
(20)	Dividends Paid	(465,000)	(175,000)	(175,000)	(175,000)	(175,000)
(21)	Other Financing Activity	(1,490)				
(22)	**Cash From Financing Activities**	(660,990)	(124,669)	(136,928)	(170,990)	(149,565)
(23)	**Total Change in Cash**	(65,785)	-	-	-	-
(24)	**Beginning Cash and Cash Equivalents**	376,455	-	-	-	-
(25)	**Ending Cash and Cash Equivalents**	310,673	-	-	-	-

* **Excludes OSS**

CERTIFICATE OF SERIVICE

I hereby certify that a copy of the testimony of William A. Allen was served on the persons stated below via electronic mail, this 13th day of September 2011

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