LARGE FILING SEPARATOR SHEET

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SECTION 2

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DESCRIPTION OF DOCUMENT

TESTIMONY / LESSER

CONTINENTAL ECONOMICS

Jonathan A. Lesser, Ph.D.
President

SUMMARY OF EXPERIENCE

Dr. Jonathan Lesser is the President of Continental Economics, Inc., and has over 25 years of experience working for regulated utilities, government, and as an economic consultant. He has extensive experience in valuation and damages analysis, from estimating the damages associated with breaking commercial leases to valuing nuclear power plants. Dr. Lesser has performed due diligence studies for investment banks, testified on generating plant stranded costs, assessed damages in commercial litigation cases, and performed statistical analysis for class certification. He has also served as an arbiter in commercial damages proceedings.

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

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

Dr. Lesser has designed economic models to value nuclear, fossil fuel, and renewable generating assets, as well as long-term power contracts in the presence of market, regulatory, and environmental uncertainty. He is the author of numerous academic and trade press articles. He is also the coauthor of *Environmental Economics and Policy*, published in 1997 by Addison Wesley Longman, *Fundamentals of Energy Regulation*, published in 2007 by Public Utilities Reports, Inc., and *Principles of Utility Corporate Finance*, published in 2011 by Public Utilities Reports, Inc. Dr. Lesser is also a contributing columnist and Editorial Board member for *Natural Gas & Electricity*.

AREAS OF EXPERTISE

- Utility rate regulation – cost of capital, depreciation, cost of service, cost allocation, rate design, and alternative regulatory structures
- Commercial damages estimation
- Cost-benefit analysis
- Regulatory policy and market design
- Economic impact analysis and input-output studies
- Environmental compliance and litigation
- Market power analysis
- Load forecasting
- Energy asset valuation and due diligence

SELECTED EXPERT TESTIMONY AND REPORTS

Industrial Energy Users of Ohio

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

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

Southwest Gas Corporation

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

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

Portland Natural Gas Shippers

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

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

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

Independent Power Producers of New York

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

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

Maryland Public Service Commission

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

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

Alliance to Protect Nantucket Sound

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

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

Brookfield Energy Marketing, LLC

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

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

Public Service Company of New Mexico

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

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

M-S-R Public Power Agency

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

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

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

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

Financial Marketers

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

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

Southwest Gas Corporation and Salt River Project

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

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

New York Regional Interconnect, Inc.

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

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

Occidental Chemical Corporation

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

Subject: Compliance of wholesale power sales agreement with FERC standards

EPIC Merchant Energy, LLC, et al.

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

  Subject: Allocation of revenue sufficiency guarantee costs.

Cottonwood Energy, LP

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

  Subject: Benefits of transmission capacity investments.

Redbud Energy, LP

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

  Subject: Reasonableness of PSO's 2008 RFP design.

The NRG Companies

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

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

Dynegy Power Marketing, LLC

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

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

Constellation Energy Group

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

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

Government of Belize, Public Utility Commission

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

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

Federal Energy Regulatory Commission

- Technical hearings on wholesale electric capacity market design.

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

Dogwood Energy, LLC

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

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

Independent Power Producers of New York

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

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

Empresa Eléctrica de Guatemala

- Rate proceeding before the Comisión Nacional de Energía Eléctrica

  Subject: Rate of return for an electric distribution company

Electric Power Supply Association

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

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

Constellation Energy Commodities Group, LLC

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

Suiza Dairy Corporation and Vaquería Tres Monjitas, Inc.

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

DPL Inc.

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

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

IGI Resources, LLC and BP Canada Energy Marketing Corp.

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

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

Baltimore Gas and Electric Co.

- Maryland Public Service Commission (Case No. 9099)

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

- Maryland Public Service Commission (Case No. 9073)

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

- Maryland Public Service Commission (Case No. 9063)

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

Pemex-Gas y Petroquímica Básica

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

BP Canada Marketing Corp.

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

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

Transmission Agency of Northern California

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

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

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

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

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

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

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

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

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

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

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

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

State of New Jersey Board of Public Utilities

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

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

Sierra Pacific Power Corp.

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

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

Matanuska Electric

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

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

Duke Energy North America, LLC

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

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

Keyspan-Ravenswood, LLC

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

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

Electric Power Supply Association

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

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

Vermont Department of Public Service

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

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

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

Pipeline shippers

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

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

Arkansas Oklahoma Gas Corp.

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

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

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

Entergy Nuclear Vermont Yankee, LLC

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

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

Central Illinois Lighting Company

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

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

Citizens Utilities Corp.

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

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

Dynegy LNG Production, LP

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

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

Missouri Gas Energy Corp.

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

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

Green Mountain Power Corp.

- Vermont Public Service Board rate proceedings
  - *In the Matter of Green Mountain Power Corporation requesting a 12.93% Rate Increase to take effect January 22, 1999*, Docket No. 6107. Subject: Analysis of the appropriate discount rate, treatment of environmental costs, and the treatment of risk and uncertainty as part of a major power-purchase agreement with Hydro-Quebec.

- *Investigation into the Department of Public Service's Proposed Energy Efficiency Utility*, Docket No. 5980. Subject: Analysis of distributed utility planning methodologies and environmental costs.
- *Tariff Filing of Green Mountain Power Corporation requesting a 16.7% Rate Increase to take effect 7/31/97*, Docket No. 5983. Subject: Analysis of distributed utility planning methodologies and avoided electricity costs.
- *Tariff Filing of Green Mountain Power Corporation requesting a 16.7% Rate Increase to take effect 7/31/97*, Docket No. 5983. Subject: Valuation of a long-term power purchase contract with Hydro-Quebec in the context of a determination of prudence and economic used-and-usefulness.

United Illuminating Company

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

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

OTHER COMMERCIAL LITIGATION EXPERIENCE

- *IMO Industries v. Transamerica.* Estimated the appropriate discount rate to use for estimating damages over time associated with a failure of the insurance companies to reimburse asbestos-related damage claims and the resulting losses to the firm's value.
- *John C. Lincoln Hospital v. Maricopa County.* Performed statistical analysis to determine the value of a class of unpaid hospital insurance claims.
- *Catamount/Brownell, LLC. v. Randy Rowland.* Prepared an expert report on the damages associated with breach of commercial lease.
- *Lyubner v. Sizzling Platters, Inc..* Performed an econometric analysis of damage claims based on sales impacts associated with advertising.
- *Pietro v. Pietro.* Estimated pension benefits arising from a divorce case.
- *Nat'l. Association of Electric Manufacturers v. Sorrell.* Testified on the costs of labeling fluorescent lamps and the impacts of labeling laws on the demand for electricity.

ARBITRATION CASES

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

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

Served as neutral on a three-person arbitration panel.

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

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

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

SELECTED BUSINESS CONSULTING EXPERIENCE

- For an environmental advocacy group, critically evaluated the financial implications of operating restrictions for an off-shore wind generating facility stemming from requirements under the U.S. Endangered Species Act.
- For a major investor-owned utility in the US, prepared a new system of short-term peak and energy forecasting models.
- For a major wholesale electric generation company, prepared comprehensive economic impact studies for use in FERC hydroelectric relicensing proceedings.
- For a major investor-owned utility in the Southwest US, prepared a detailed econometric model and wrote a comprehensive report on residential price elasticity that was required by regulators.
- For a major investor-owned utility in the Southwest US, developed a methodology to value nuclear plant leases that incorporated future uncertainty regarding greenhouse gas regulations.
- Faculty member, PURC/World Bank International Training Program on Utility Regulation and Strategy, University of Florida, Public Utility Research Center, Gainesville, FL, 2008 – 2009. Courses taught:
  - Sector Issues: Basic Techniques–Energy
  - Sector Issues in Rate Design: Energy
  - Sector Issues in Rate Design: Energy–Case Studies

  - Transmission Pricing Issues

- For a major solar energy firm, evaluated costs and benefits of alternative solar technologies; assisted with siting and transmission access issues.
- For industrial customers in the State of Vermont, prepared a position paper on the impacts of demand side management funding on electric rates and competitiveness.
- For a major New York brokerage firm, performed a fairness opinion valuation of a gas-fired electric generating facility.
- For electric utilities undergoing restructuring, developed comprehensive economic models to value buyer offers associated with nuclear power plant divestitures.
- For a large municipal electric utility in Florida, analyzed real option values of alternative proposed purchased generation contracts whose strike prices were tied to future natural gas and oil prices, and developed contract recommendations.
- For a municipal electric utility in Florida, developed an analytical model to determine risk-return tradeoffs of alternative generation portfolios, identify an efficient frontier of generation asset portfolios, and recommended asset purchase and sale strategies.
- For Central Vermont Public Service Corp. and Green Mountain Power Corp., developed analyses of distribution capacity investments accounting for uncertainty over future peak load growth.
- For a major electric utility in Latin America, developed risk management strategies for hedging natural gas supplies with minimal up-front investment; prepared training materials for utility staff; and wrote the utility's risk management Policies and Procedures Manual.
- For a major nuclear plant owner and operator in the U.S., prepared reports of the economic benefits of nuclear plant operation and development.
- For the Electric Power Supply Association, prepared numerous policy papers addressing wholesale electric market design and competition.
- For the California Energy Commission, developed a new policy approach to renewables feed-in tariffs and developed portfolio analysis models to develop an "efficient frontier" of generation portfolios for the state.

- For a major nuclear plant owner and operator, assessed the likelihood of relicensing a specific nuclear plant in New England, given state regulatory concerns over on-site spent fuel storage.
- For a large investor-owned utility in the Southeast, analyzed alternative environmental compliance strategies that directly incorporated uncertainty over future emissions costs, environmental regulations, and alternative pollution control technology effectiveness.
- For a Special Legislative Committee of the Province of New Brunswick, served as an expert advisor on the development of a deregulated electric power market.
- For the Bonneville Power Administration, developed models to assess the economic impacts of local generation resource development in Washington State and Oregon.
- For an electric utility in the Pacific Northwest, assisted in negotiations surrounding relicensing of a large hydroelectric generating facility.
- Served as an expert advisor for the Northwest Power Planning Council regarding future power supplies, load growth, and economic growth.

EDUCATION

- Ph.D., Economics, University of Washington
- M.A., Economics, University of Washington
- B.S., Mathematics and Economics (with honors), University of New Mexico

EMPLOYMENT HISTORY

- 2009–Present: Continental Economics, President.
- 2004–2009: Bates White, LLC, Partner, Energy Practice.
- 2003–2004: Vermont Dept. of Public Service, Director of Planning.
- 1998–2003: Navigant Consulting, Senior Managing Economist.
- 1993–1998: Green Mountain Power Corporation, Manager, Economic Analysis.
- 1986–1993: Washington State Energy Office, Energy Policy Specialist.
- 1984–1986: Pacific Northwest Utilities Conference Committee, Energy Economist.
- 1983–1984: Idaho Power Corporation, 1982-1983. Load Forecasting Analyst.

PROFESSIONAL ACTIVITIES

- Reviewer, *Journal of Regulatory Economics*
- Reviewer, *The Energy Journal*
- Reviewer, *Energy*
- Reviewer, *Energy Policy*

PROFESSIONAL ASSOCIATIONS

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

PUBLICATIONS

Peer-reviewed journal articles

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

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

Books and contributed chapters

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

Trade press publications

- Lesser, J., "Salmon and Wind Dueling for Subsidies in the Pacific Northwest," *Natural Gas & Electricity* (July 2011):18-20.
- Lesser, J., "Nuclear Fallout," *Natural Gas & Electricity* (May 2011):31-33.
- Lesser, J., "Texas Two-Step: EPA's Greenhouse Gas Permitting Takeover," *Natural Gas & Electricity* (March 2011):21-23.

- Lesser, J., "Looking Forward: Energy and the Environment through 2012," *Natural Gas & Electricity* (January 2011):30-32.
- Lesser, J., "First-Mover Disadvantage: Offshore Wind's False Economic Promises," *Natural Gas & Electricity* (November 2010): 26-28.
- Lesser, J., "Will the BP Disaster Affect Natural Gas and Electricity Markets?," *Natural Gas & Electricity* (August 2010): 23-24.
- Lesser, J., "Renewable Energy and the Fallacy of 'Green' Jobs," *The Electricity Journal* (August 2010):45-53.
- Lesser, J., "Let the Tough Choices Begin: Affordable or Green?," *Natural Gas & Electricity* (June 2010): 27-29.
- Lesser, J., "Will Shale Gas Production be Damaged by Too Many Fraccing Complaints?," *Natural Gas & Electricity* (April 2010): 31-32.
- Lesser, J., "As the Climate Turns: The Saga Continues," *Natural Gas & Electricity* (February 2010): 29-32.
- Lesser, J. and N. Puga, "Public Policy and Private Interests: Why Transmission Planning and Cost-Allocation Methods Continue to Stifle Renewable Energy Policy Goals," *The Electricity Journal* (December 2009): 7-19.
- Lesser, J, "Short Circuit: Will Electric Cars Provide Energy and Environmental Salvation?" *Natural Gas & Electricity* (November 2009): 27-28.
- Lesser, J., "Green is the New Red: The High Cost of Green Jobs," *Natural Gas & Electricity* (August 2009): 31-32.
- Lesser, J., "Regulating Greenhouse Gas Emissions: EPA Gets Down," *Natural Gas & Electricity* (June 2009): 31-32.
- Lesser, J., "Being Reasonable While Regulating Greenhouse Gas Emissions under the Clean Air Act," *Natural Gas & Electricity* (April 2009): 30-32.
- Lesser, J., "Renewables, Becoming Cheaper, Are Suddenly Passé," *Natural Gas & Electricity* (February 2009): 30-32.
- Lesser, J., "Measuring the Costs and the Benefits of Energy Development," *Natural Gas & Electricity* (December 2008): 30-32.
- Lesser, J., "Comparing the Benefits and the Costs of Energy Development," *Natural Gas & Electricity* (October 2008): 31-32.
- Lesser, J., "New Source Review Is Still Anything but Routine," *Natural Gas & Electricity* (August 2008): 31-32.

- Lesser, J., and N. Puga, "PV versus Solar Thermal," *Public Utilities Fortnightly* 146 (July 2008), pp. 16-20, 27.
- Lesser, J., "Cap-and-Trade for Gasoline?," *Wall Street Journal*, June 14, 2008, A14.
- Lesser, J., "Kansas Secretary Unilaterally Bans Coal Plants," *Natural Gas & Electricity* (June 2008): 30-32.
- Lesser, J., "Seeing Through a Glass, Darkly, Banks Approach Coal-Fired Power Financing," *Natural Gas & Electricity* (April 2008): 29-31.
- Lesser, J., "The Energy Independence and Security Act of 2007: No Subsidy Left Behind," *Natural Gas & Electricity* (February 2008): 29-31.
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Selected speaking engagements

- "The Failures of Transmission Planning and Policy," Harvard Electric Policy Group, February 25, 2010.
- "Financing the Smart Grid," Energy Bar Association Seminar, Washington, DC, December 4, 2009.
- "Renewable Power: At the Crossroads of Economics and Policy," Presentation to the Utilities State Government Organization, Newport, Rhode Island, July 13, 2009.
- "The Stimulus Act and Laws they Didn't Teach You in Law School," presentation to the 27th National Regulatory Conference, Williamsburg, VA, May 19, 2009.
- "Rate Recovery for Capital Intensive Generation: Rate Base and Construction Work in Progress," Law Seminars International, Las Vegas, NV, February 5, 2009.
- "Financial Risks Faced by Regulated Utilities: Implications for the Cost of Capital and Ratemaking Policies," Law Seminars International, Las Vegas, NV, February 7, 2008.
- "Alternative Regulatory Structures and Tariff Mechanisms: Practical approaches to providing low-cost, environmentally responsible energy and how to avoid some dangerous pitfalls." Western Energy Institute, October 1, 2007.
- "Economics and Energy Regulation." Law Seminars International, Washington, DC, March 15-16, 2007.
- "Energy in the Northeast: Resource Adequacy & Reliability." Law Seminars International, Boston, MA, October 16–17, 2006.
- "Energy in the Southwest: New Directions in Energy Markets and Regulations." Law Seminars International, Santa Fe, NM, July 14, 2006.
- "Energy and the Environment." Vermont Journal of Environmental Law, South Royalton, VT, March 10, 2006.
- "Electricity and Natural Gas Regulation: An Introduction." Law Seminars International, Washington, DC, March 17–18, 2005.

AEP AMERICAN® ELECTRIC POWER

2010 Fact Book

45th EEI
Financial Conference
Palm Desert, CA

Exhibit JAL-2

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

AEP®

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition particularly in Ohio, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to recover I&M's Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation including requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance), resolution of litigation (including the dispute with Bank of America), our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes and other catastrophic events and our ability to recover through rates the remaining unrecovered investment, if any, in generating units that may be retired before the end of their previously projected useful lives.

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Company Overview

AEP Service Territory

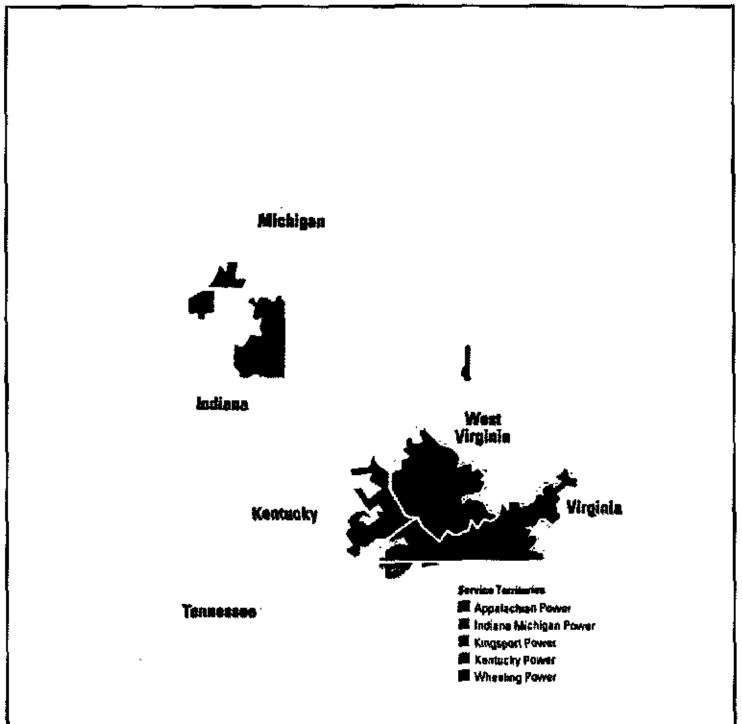
AEP EAST OPERATING COMPANIES

EAST REGULATED UTILITIES

Appalachian Power Company (APCo)
Indiana Michigan Power Company (I&M)
Kingsport Power Company (KGPCo)
Kentucky Power Company (KPCo)
Wheeling Power Company (WPCo)

AEP OHIO

Columbus Southern Power Company (CSPCo)
Ohio Power Company (OPCo)



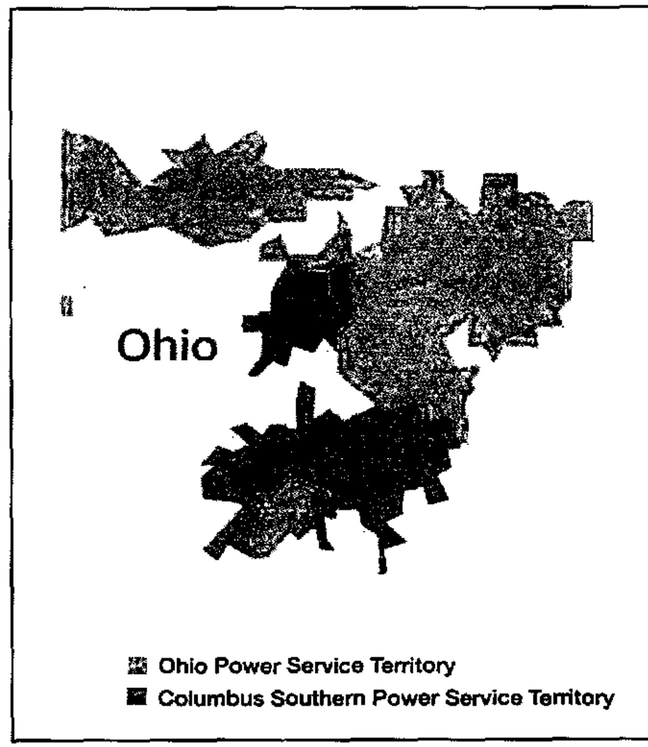


Exhibit JAL-2

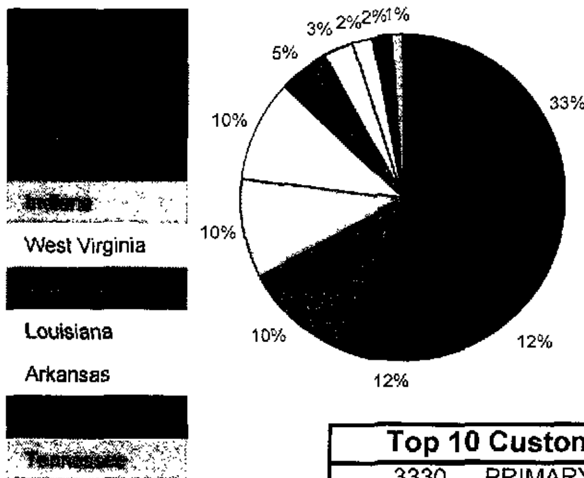
2009 Retail Revenue

CUSTOMER PROFILE

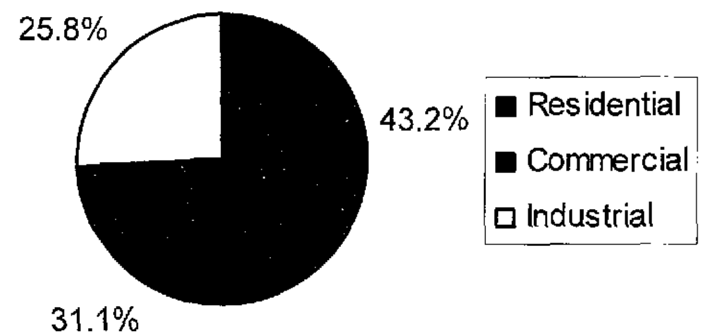
AEP'S SERVICE TERRITORY ENCOMPASSES

APPROXIMATELY 5 MILLION CUSTOMERS IN 11 STATES

Percentage of AEP System Retail Revenues



Retail Revenue Composition by Customer Class*



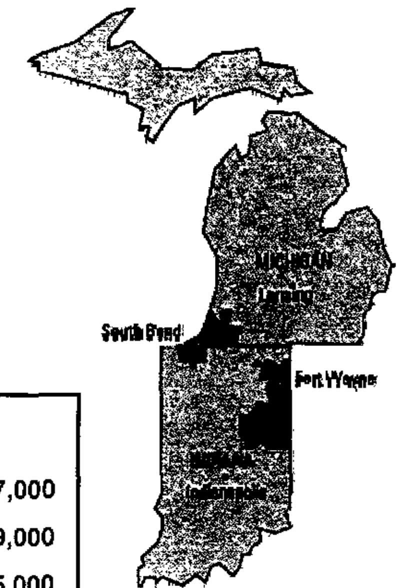
Top 10 Customers Across the AEP System By NAICS Code	
3330	PRIMARY SMELTING & REFINING OF NONFERROUS METALS
2800	CHEMICALS & ALLIED PRODUCTS
2911	PETROLEUM REFINING
1220	BITUMINOUS COAL & LIGNITE MINING
2600	PAPERS & ALLIED PRODUCTS
3060	FABRICATED RUBBER PRODUCTS
1389	OIL & GAS FIELD SERVICES
2000	FOOD & KINDRED PRODUCTS
3272/3281	STONE CLAY & CONCRETE PRODUCTS
3700	TRANSPORTATION EQUIPMENT

Source: Form 10-K.
*Note: Figures do not include Other Retail Sales

Exhibit JAL-2

Indiana Michigan Power

President and Chief Operating Officer: Paul Chodak



Indiana Michigan Power Company (I&M)

(organized in Indiana in 1925) is engaged in the generation, transmission and distribution of electric power to approximately 583,000 retail customers in northern and eastern Indiana and southwestern Michigan, and in supplying and marketing electric power at wholesale to other electric utility companies, rural electric cooperatives, municipalities and other market participants. At December 31, 2009, I&M had 3,008 employees. Since 1975, I&M has leased and operated the assets of the municipal system of the City of Fort Wayne, Indiana. This lease extends through February 2010 and its termination is currently being litigated. In addition to its AEP System interconnections, I&M is interconnected with the following unaffiliated utility companies: Central Illinois Public Service Company, Duke Ohio, Commonwealth Edison Company, Consumers Energy Company, Illinois Power Company, Indianapolis Power & Light Company, Louisville Gas and Electric Company, Northern Indiana Public Service Company, Duke Indiana and Richmond Power & Light Company. I&M is a member of PJM.

PRINCIPAL INDUSTRIES SERVED:

Primary Metals
Chemicals and Allied Products
Transportation Equipment
Rubber and Miscellaneous Plastic Products
Fabricated Metals Products

Total Customers at 12/31/09:		
Residential		**507,000**
Commercial		**69,000**
Industrial		**5,000**
Other		**2,000**
Total		**583,000**
Generating Capacity		**5,821 MW***
Generating Capacity by Fuel Mix:		
• **Coal:**	**68.6%**	
• **Nuclear:**	**31.1%**	
• **Hydro:**	**0.3%**	
Transmission Miles		**5,347**
Distribution Miles		**20,218**

* Includes AEGCo's share of Rockport of 1, 310MW

Exhibit JAL-2

Domestic Generation

Generation Capacity*

Company	MW Capacity
AEP Generating Co	2,496
Appalachian Power Co	6,287
Columbus Southern Power Co	3,738
Indiana Michigan Power Co	4,511
Kentucky Power Co	1,078
Ohio Power Co	8,508
Public Service of Oklahoma	4,465
Southwestern Electric Power Co	5,307
Texas North Co**	647
OVEC Capacity ***	980
Domestic IPPs	311
Long Term Renewable Purchase Power Agreements	1,582
	39,910

* Capacity amounts represent the nominal capacity (the number of MW expected to be produced on a routine basis).

** Includes 270MW of mothballed/retired/decommissioned generation

*** Represents AEP's 43.5% interest in Ohio Valley Electric Corporation (OVEC), which supplies the power requirements of a uranium enrichment plant near Portsmouth, Ohio owned by the DOE.

Coal/Lignite #	25,736	65%
Natural Gas/Oil	9,371	23%
Nuclear	2,191	5%
Wind/Hydro/Pumped Storage	2,612	7%
Total Generating Capacity	39,910	100%

Includes AEP's 43% ownership of OVEC

At the conclusion of our current environmental retrofit program, over 56% of our 25,736 MW coal-fired generation fleet will be equipped with SCRs and over 71% will be scrubbed (FGDs).

Jurisdictional Off-System Sales Sharing Summary

STATE	OSS Sharing?	Detail
Arkansas	Yes, above and below base levels	Up to $758,600 annual margin, ratepayers receive 100%. From $758,601 to $1,167,078, ratepayers receive 85%. Above $1,167,078, ratepayers receive 50%.
Indiana	Yes	There is $37.5 million built into Indiana's base rates. Above $37.5 million, ratepayers received 50%
Kentucky	Yes, above and below base levels	Sharing occurs above and below levels included in base rates of $15,290,363, ratepayers receive 60%.
Louisiana	Yes, above base levels	Up to $874,000 annual margin, ratepayers receive 100%. From $874,001 to $1,314,000, ratepayers receive 85%. Above $1,314,000, ratepayers receive 50%.
Michigan	Yes	75% of profits are shared with ratepayers.
Ohio	No	n/a
Oklahoma	Yes	75% of profits are shared with ratepayers.
Tennessee	No	n/a
Texas (SPP)	Yes	90% of profits are shared with ratepayers.
Virginia	Yes	75% of profits are shared with ratepayers.
West Virginia	Yes	100% of profits passed back to ratepayers through the Expanded Net Energy Cost (ENEC) clause.

Exhibit JAL-2

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSE TO INDUSTRIAL ENERGY USERS-OHIO DISCOVERY REQUEST CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO SECOND SET

INTERROGATORY

INT-090. On page 8 of Laura Thomas' testimony, she states that she has included a component in the Competitive Benchmark price called a transaction risk adder. What are the components for determining that amount?

RESPONSE

The amount of the Transaction Risk Adder identified on page 8 of Company witness Thomas' testimony was based on a review of the experiences of various deregulated states and reflects a reasonable and balanced approach to determining a Competitive Benchmark price. See IEU INT-091 Attachments 2 and 3 for the analysis used to support the amount of the Transaction Risk Adder. See page 8 of Company witness Thomas' testimony for a listing of the types of items covered by the Transaction Risk Adder.

Prepared by: Thomas

RETAIL ADMIN FEE - SUPPORTING ANALYSES

STATE	ENTITY / FORUM	AMOUNT / DESCRIPTION	DATE	RATIONALE
Pennsylvania	FirstEnergy and Penn Power	The Administrative Charge varies by company and class, but is approximately $3.00/MWh	2009	An administrative fee for applicable costs by customer class is applied to each kWh of Default Service delivered to Retail Customers - (there is also an uncollectible accounts expense fee that reflects additional uncollectible accounts expense cost incurred by the Company as a result of providing Default Service that is not shown in the $3/MWh charge.)
Ohio	SB 221	Section 4928.20(J), Ohio Revised Code, provides some general guidance on the items that should be included in the Competitive Benchmark.	2008	In regards to the market price for governmental aggregation customers that return to the utility for competitive retail service, the provision states that "...such market prices shall include, but not be limited to"; Capacity Charges, Energy Charges, All charges associated with the provision of power supply through the regional transmission organization..., and all other costs incurred by the utility that are associated with the procurement, provision and administration of that power supply.
Ohio	DE Ohio	DE Ohio's MRO filing includes a Supply Management Fee of $2.81/MWh in the Forward Pricing calculation, or 4.8% of the total price.	2010	The Supply Management Fee is described as the day-to-day costs of business for the CRES provider.
Ohio	DE Ohio	DE Ohio included a Supply Management Fee of $3.67 in the Forward Pricing calculation, or 4% of the total price.	2008	The Supply Management Fee is described as the day-to-day costs of business for the CRES provider.
Maryland	PEPCO Order No. 78710 - Administrative Charge	Varies by class but is roughly $6.00/MWh - This charge includes return (profit) to the utility and incremental costs related to SOS. (This charge is bypassable for customers who shop.)	2003 through the present	Administrative charges are trued-up on an annual basis - as of this most recent filing, PECO was carrying a net under collection.

**COLUMBUS SOUTHERN POWER COMPANY'S
AND OHIO POWER COMPANY'S RESPONSES TO
FIRSTENERGY SOLUTIONS CORP.'S
DATA REQUEST
CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO
FIRST SET**

INTERROGATORY

RPD-007 Referring to page 8:11-15 of Ms. Thomas' testimony: All work papers, electronic files (with formulas intact), assumptions, and calculations that were utilized to calculate and develop the Retail Administration Charge for each customer class and period analyzed, including identification of all sources of all of the underlying data used

RESPONSE

See the Company's response to IEU INT-089.

Prepared By: Laura J Thomas

**COLUMBUS SOUTHERN POWER COMPANY'S
AND OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO
DISCOVERY REQUEST
CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO
SECOND SET**

INTERROGATORY

INT-089. On page 8 of Laura Thomas' testimony, she states that she has included a component for administration. The al'nount of $5/MWH is used in workpapers. What are the components for determining that amount?

RESPONSE

The amount of the Retail Administration Charge identified on page 8 of Company witness Thomas' testimony was based on a review of the experiences of various deregulated states and reflects a reasonable and balanced approach to determining a Competitive Benchmark price. Please see IEU INT-091 Attachments 1 and 3 for the analysis used to support the amount of the Retail Administration Charge. See page 8 of Company witness Thomas' testimony for a listing of the types of items covered by the Retail Administration Charge.

Prepared by: Thomas

Ohio Power Company ($-MW/Day)			
Planning Year	11/12	12/13	13/14
FRR	387.78	387.78	387.78
RPM	110.00	16.46	27.73
Delta	277.78	371.32	360.05

Columbus Southern Power ($-MW/Day)			
Planning Year	11/12	12/13	13/14
FRR	299.81	299.81	299.81
RPM	110.00	16.46	27.73
Delta	189.81	283.35	272.08

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSES TO FIRSTENERGY SOLUTIONS CORP.'S DATA REQUEST CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO FIRST SET

INTERROGATORY

RPD-005 Referring to page 7:14-16 of Ms. Thomas' testimony: All work papers, electronic files (with formulas intact), assumptions, and calculations that were utilized to develop the capacity component rates provided in AEP-Ohio's Initial Comments filed in Case No 10-2929- EL-UNC on January 7, 2011, including identification of all sources of all of the underlying data used

RESPONSE

Company witness Thomas does not sponsor the requested documents but relies upon the Company's proposal in Case No 10-2929-EL-UNC as input for portions of her testimony and exhibits. As explained on page 22 of the testimony of Company witness Thomas, the Company proposes that compliance calculations reflecting final ESP rates, Competitive Benchmark prices and switching rules be performed As such, those calculations would reflect the outcome of Case No. 10-2929-EL-UNC if the Commission issues a decision in that case prior to a decision in this ESP case. Notwithstanding the above, see the Company's January 7, 2011 filing in Case No 10-2929-EL-UNC for the requested information.

Prepared By: Counsel

Exhibit JAL-8

COLUMBUS SOUTHERN POWER COMPANY'S
AND OHIO POWER COMPANY'S RESPONSE TO
THE OFFICE OF THE OHIO CONSUMERS' COUNSEL
DISCOVERY REQUEST
CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO
FOURTH SET

INTERROGATORY

INT-136. How are off-system sales (profits) treated in the current ESP filing for AEP Ohio?

RESPONSE

OSS profits are adjusted out of the Company's pro forma financial statements as shown on PJN Exhibit-3, page 7.

Prepared By: Philip J. Nelson

**COLUMBUS SOUTHERN POWER COMPANY'S
AND OHIO POWER COMPANY'S RESPONSE TO
THE OFFICE OF THE OHIO CONSUMERS' COUNSEL
DISCOVERY REQUEST
CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO
FOURTH SET**

INTERROGATORY

INT-139. What was the actual total margin (profit) from all off-system sales each year, for the years 2000 through present for CSP and for OPCo?

RESPONSE

OPCo & CSP 's OSS margins ($000)

	OPCo	CSP
2010	81,304	73,533
2009	61,879	51,268
2008	181,498	146,560
2007	171,392	142,730
2006	199,737	133,501
2005	145,062	89,921
2004	96,988	64,849
2003	73,629	53,373
2002	77,282	57,333
2001	106,151	75,036
2000	136,352	89,001

Prepared By: Philip J. Nelson

**COLUMBUS SOUTHERN POWER COMPANY'S
AND OHIO POWER COMPANY'S RESPONSE TO
THE OFFICE OF THE OHIO CONSUMERS' COUNSEL
DISCOVERY REQUEST
CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO
FOURTH SET**

INTERROGATORY

INT-140. What is the most recent estimate of the total margin (profits) from all off-system sales each year, for each year of the ESP term proposed for CSP and for OPCo?

RESPONSE

OSS Pre Tax Margins

	$000		
Period	**CSP**	**OPC**	**Total**
2012	130,254	83,791	214,045
2013	147,378	107,615	254,993
Jan - May 2014	70,767	55,992	126,759

Prepared By: Philip J. Nelson

**COLUMBUS SOUTHERN POWER COMPANY'S
AND OHIO POWER COMPANY'S RESPONSE TO
THE OFFICE OF THE OHIO CONSUMERS' COUNSEL
DISCOVERY REQUEST
CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO
FOURTH SET**

INTERROGATORY

INT-143. What percentage of OPCo's annual generation for the years 2000 through 2010, by year, was assigned to off-system sales?

RESPONSE

See OCC INT-143 Attachment 1.

Prepared By: Philip J. Nelson

OCC 4-143 Attachment 1

OPCO and CSP Annual Percentage of Generation Assigned to Off-System Sales

	OPCO	CSP
2000	15.40%	17.50%
2001	18.60%	19.90%
2002	19.90%	18.10%
2003	23.60%	24.90%
2004	19.90%	26.20%
2005	18.50%	23.40%
2006	20.20%	20.80%
2007	13.90%	27.30%
2008	11.40%	19.20%
2009	7.50%	15.30%
2010	8.90%	15.30%

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSE TO THE OFFICE OF THE OHIO CONSUMERS' COUNSEL DISCOVERY REQUEST CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO FOURTH SET

INTERROGATORY

INT-146. In addition to megawatt-hours sales, what other off-system sales net revenues (i.e., capacity, ancillary services, etc.) were generated by CSP for the years 2000 through 2010? Were any of these net revenues used to lower rates charged to Ohio jurisdictional customers? If so, how was this done and what amounts were used to lower rates?

RESPONSE

CSP received its MLR share of OSS margins related to capacity sales made by the AEP East Pool into PJM's RPM market. Those OSS margins are included in the Company's response to OCC INT-139.

See Company's response to OCC INT-141 and OCC INT-142.

Prepared By: Philip J. Nelson

**COLUMBUS SOUTHERN POWER COMPANY'S
AND OHIO POWER COMPANY'S RESPONSE TO
THE OFFICE OF THE OHIO CONSUMERS' COUNSEL
DISCOVERY REQUEST
CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO
FOURTH SET**

INTERROGATORY

INT-147. In addition to megawatt-hours sales, what other off-system sales net revenues (i.e., capacity, ancillary services, etc.) were generated by OPCo for the years 2000 through 2010? Were any of these net revenues used to lower rates charged to Ohio jurisdictional customers? If so, how was this done and what amounts were used to lower rates?

RESPONSE

OPCo received its MLR share of OSS margins related to capacity sales made by the AEP East Pool into PJM's RPM market. Those OSS margins are included in the Company's response to OCC INT-139.

See Company's response to OCC INT-141 and OCC INT-142.

Prepared By: Philip J. Nelson

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSE TO FIRSTENERGY SOLUTIONS DISCOVERY REQUEST CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO FOURTH SET

INTERROGATORY

INT-4-005. In Exhibit LJT-2, does the "2011 Base ESP 'g' rate" include both energy and capacity costs?

RESPONSE:

The Company objects to this request as seeking information that is neither relevant nor reasonably calculated to lead to the discovery of admissible evidence. Without waiving these objections or any general objection the Company may have, the Company states as follows

SB221 does not require rates for generation service, including capacity and energy, to be based on cost AEP Ohio has not conducted a cost of service study for unbundled generation service. However, the 2011 Base ESP 'g' rate includes both energy and capacity.

Prepared By: Laura J. Thomas

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSE TO FIRSTENERGY SOLUTIONS DISCOVERY REQUEST CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO FOURTH SET

INTERROGATORY NO. 4-15:

INT-4-015. In Exhibit LJT-2, does the "2011 Base ESP 'g' rate" include ancillary service charges that CSP and OPCo incur as members in PJM? If the answer is "yes," please Identify all supporting workpapers and analysis that documents all of the ancillary service charges that form the basis for the charges included in the "2011 Base ESP 'g' rate "

RESPONSE:

The Company objects to this request as seeking information that is neither relevant nor reasonably calculated to lead to the discovery of admissible evidence. Without waiving these objections or any general objection the Company may have, the Company states as follows.

SB221 does not require rates for generation service, including capacity and energy, to be based on cost AEP Ohio has not conducted a cost of service study for unbundled generation service. However, the 2011 Base ESP 'g' rate includes ancillary service charges.

See the Company's response to FES 4-009.

Prepared By: Laura J. Thomas

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSE TO FIRSTENERGY SOLUTIONS DISCOVERY REQUEST CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO TENTH SET

INTERROGATORY

INT-10-11 Please explain whether each of the following factors are credited against Your alleged capacity costs under the ESP:

a) Capacity sales under the AEP East agreement;
b) Energy sales under the AEP East agreement;
c) Other market sales of energy only to non-affiliates;
d) Other market sales of capacity only to non affiliates; and,
e) Combined capacity and energy sales to non-affiliates.

RESPONSE

See Companies' response to FES INT 10-05.

SUPPLEMENTAL RESPONSE

If "alleged" capacity costs is defined as the capacity costs contained in our current ESP or SSO rates, the Company's ESP is not cost based and the Company has not identified any specific capacity costs or capacity credits in its rates.

Prepared By: Philip J. Nelson/ Laura J. Thomas

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSE TO FIRSTENERGY SOLUTIONS DISCOVERY REQUEST CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO NINTH SET

INTERROGATORY

INT-9-004. Regarding Mr. Rousch's testimony, is there a cost basis for uniformly increasing the 2012 base generation rates to determine the base generation rates for January 2013 to May 2014?

RESPONSE

No. The basis for the uniform increase is to maintain the relative market price relationships established in the 2012 rates in the January 2013 to May 2014 rates

Prepared By: David M. Roush

**COLUMBUS SOUTHERN POWER COMPANY'S
AND OHIO POWER COMPANY'S
DISCOVERY RESPONSES TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUESTS
PUCO CASE NOS. 11-346-EL-SSO and 11-348-EL-SSO
FOURTH SET**

INTERROGATORY

INT-166. In the testimony of Phillip Nelson at 16-17, Mr. Nelson requests that the Environmental Investment Carrying Cost Rider ("EICCR") be made nonbypassable.

a. Under what provision(s) of Chapter 49, Revised Code, are the Companies seeking to establish the nonbypassable charge for incremental environmental investment?

b. Identify each investment project for which the Companies are seeking a nonbypassable charge.

c. For each investment project identified in (b), indicate if the project was competitively bid.

d. For each investment project identified in (b), identify the documents that support that the project was competitively bid.

e. For each investment project identified in (b), identify any other internal review process that was undertaken to assure that the project was a reasonably priced solution to environmental compliance.

f. For each investment project identified in (b), identify any documents that demonstrate that the review process that was undertaken to assure the project was a reasonably priced solution to environmental compliance.

g. For each investment project identified in (b), indicate for each year the amount to be recovered as construction work in progress.

h. For each investment project identified in (b), indicate for each year the amount to be recovered that is not construction work in progress.

INT-166 (CONTINUED)

i. For each year, what is the total amount of construction work in progress that CSP and OPCo are seeking to recover under the EICCR?

j. For each year, what is the total amount that CSP and OPCo are seeking to recover that is not construction work in progress?

k For each investment project identified in (b), identify the FERC account under which the investment project is booked.

l. Under what provision(s) of Chapter 49, Revised Code, are the Companies seeking to collect depreciation and/or operating and maintenance expense with regard to investment projects that are classified as construction work in progress?

RESPONSE

a. The Company objects to this request as seeking a legal conclusion or opinion that is more appropriate for briefing and argument by counsel. Without waiving this objection or any general objection the Company may have, the Company states that statutes that generally support ESP rider cost recovery include but are not necessarily limited to R.C. 4905.31, 4928.02, 4928.141, 4928.143, 4928.144, 4928.64, and 4928.66. Statutes that further support this rider include but are not necessarily limited to R.C. 4928 143(B)(2)(b), (d), and (e).

b. See Company witness Nelson's workpaper PJN (Support AEM-1) contained in volume 5 of the Company's filing for estimated projects for 2012. See also the Company's filings in Case Nos. 10-155-EL-RDR and 11-1337-EL-RDR.

c. Please see IEU INT-166, Attachment 1 for AEP's standard operating procedure for procurement related to construction of generating facilities.

d. AEP Ohio objects due to the voluminous nature of this request. The projects at issue involve hundreds of contracts, many on the same project. If IEU desires to review the documents AEP Ohio can gather the numerous documents and provide IEU an opportunity to review at AEP Ohio offices.

e. For each of the Major Projects listed on CSP Schedule 2, a capital improvement requisition was prepared. The CI provid is reviewed and approved by senior management and depending on the total cost of the project, the board of directors.

f. See Company response to IEU INT-166, part e.

g. The Company has not identified for each project the amount for each year to be recovered through construction work in progress.

h. The Company has not identified for each project the amount for each year to be recovered that is not construction work in progress.

i. The Company has not identified the total amount for each year to be recovered through construction work in progress.

INT-166 (CONTINUED)

j. The Company has not identified the total amount for each year to be recovered that is not construction work in progress.
k. The Investments for the major projects included in Schedule 2 are originally recorded in FERC account 107. As portions of these projects are completed, the balances move into FERC account 106 (completed construction not classified) then into FERC account 101 (Electric Plant in Service). The Company has not the portion of the projects in 107, 106 or 101.
l. See Company response to IEU INT-166, part a.

Prepared by: Philip J. Nelson

Exhibit JAL-15

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSE TO INDUSTRIAL ENERGY USERS-OHIO DISCOVERY REQUEST CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO SECOND SET

INTERROGATORY

INT-073. With regard to AEP's ESP proposal regarding recovery of environmental compliance costs, please identify the total dollar amount of such environmental compliance costs that AEP expects to recover from Ohio retail consumers within its certified service area during the proposed term of the ESP if its ESP is approved by the Commission as proposed.

RESPONSE

The Company has not calculated the total dollar amount of such environmental compliance costs for the 29 month ESP period.

Prepared by: Nelson

Exhibit JAL-16

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSE TO INDUSTRIAL ENERGY USERS-OHIO'S DISCOVERY REQUEST CASE NOS. 11-346-EL-SSO AND 11-348-EL-SSO FIRST SET

INTERROGATORY

INT-007. Prior to entering into the Memorandum of Understanding ("MOU") with Turning Point Solar did AEP seek any competitive bids for this project?

RESPONSE

The selection of the project Developer was not competitively bid.

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSE TO INDUSTRIAL ENERGY USERS-OHIO DISCOVERY REQUEST CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO SECOND SET

INTERROGATORY

INT-057. For each nonbypassable charge identified in response to Interrogatory No. 51 above, please identify whether the EDU dedicated to Ohio consumers the capacity and energy and the rate associated with the cost of the facility.

RESPONSE

See the response to IEU INT-053. The Company further states that, with respect to the Turning Point solar project proposed for recovery under the Generation Resource Rider, the capacity and energy of this facility will be dedicated to Ohio consumers.

Prepared by: Nelson/Counsel

\- - -

American Electric Power :
Company, Inc., at Sanford :
C. Bernstein & Co., LLC, :
Strategic Decisions :
Conference. :

\- - -

FIRESIDE CHAT

between Hugh and Mike Morris, Chairman and CEO of American Electric Power Company, Inc., at 8 a.m. on Wednesday, June 1, 2011.

\- - -

ARMSTRONG & OKEY, INC.
222 East Town Street, Second Floor
Columbus, Ohio 43215-5201
(614) 224-9481 - (800) 223-9481
Fax - (614) 224-5724

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Wednesday Morning Session,
June 1, 2011.

- - -

MR. WYNNE: My pleasure to introduce Mike Morris who has for the last seven years run American Electric Power, one of the country's largest integrated public utility companies. Prior to that he was for seven years the chief executive officer of Northeast Utilities System and even before then was CEO of Consumer Energy and president of Colorado Interstate Gas Company. So Mike has a very long-term prospective on the power industry and has in particular seen the industry through a massive restructuring and deregulation of its generation business in -- in parts of the country.

Today's session will be structured as a so-called fireside chat where I'll ask Mike a series of questions. While that's going on feel free to use the index cards that you have to put down any questions that you would like to see Mike answer, and we can collect those and add them to the list.

So let me just sit down. Do you prefer to take the questions sitting down or do you like --

MR. MORRIS: Yeah, no, that's fine.

So in the last handful of years we have done nine. Overall we have done 28 major environmental additions to our generation fleet. They take somewhere on the order of 40 to 50 months to do them appropriately.

If the entire industry is trying to comply with these laws in 36 months, we will be tripping over ourselves. Whatever you do tell your children to get to welding school. Welders will make $10,000 an hour because they will be like hen's teeth. It's just illogical, and it will not happen. And what we won't do as a country is shut down the U.S. economy by prematurely shutting down power plants that need to stay on to keep the economy electrified.

MR. WYNNE: Any other questions from the audience?

Let me just ask one final personal question, given your kind of unique advantage point as having run utilities for a couple of decades, which utilities other than AEP do you think have been particularly successful over the last 5 to 10 years and to what would you attribute their success?

MR. MORRIS: It's never good to sell

anybody else's stock but, look, Southern Company has done an outstanding job over probably a couple decades of managing their way through the many challenges that come their way.

I would argue that Next Era saw an opportunity to move in a direction that for a while they stood alone when they did that. They are seeing some rewards from that going forward. They paid a price for that in Florida for a while, but they seem to have that straightened out as well, so I think that they surely have done well.

Clearly cards were dealt to Exelon that have proven to be extremely beneficial, although I think the merchant players in the last 18 months have taken quite a whack. No one -- well, I shouldn't say that. No one other than the team at Devon Energy saw shale gas a decade ago and a half a decade ago. And shale gas is a massive game changer for the overall price of electricity going forward without question. I think you're looking at 30 trillion feet of deliverability into a 28, 29 trillion feet demand cycle.

The 10 years I spent in the gas industry we were overhung by about a trillion feet, and gas stayed in the $3 range that entire decade, so I think that's an eye opener for us going forward.

The whole notion of getting the price of electricity high enough to compensate for the renewables is a folly, and it will ultimately prove itself to be that.

MR. WYNNE: Right. Thank you very much, Mike. I really appreciate it.

MR. MORRIS: Thank you. Thanks for the opportunity.

\- - -

CERTIFICATE

I do hereby certify that the foregoing is a true and correct transcript of the proceedings recorded by audiotape and transcribed by me in this matter.

Karen Sue Gibson

Karen Sue Gibson, Registered
Merit Reporter.

(KSG-5371)

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AEP AMERICAN® ELECTRIC POWER

Boston Investor Meetings Hosted by Barclays Capital July 7, 2011

Exhibit JAL-19

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: the economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, electric load, customer growth and the impact of retail competition, particularly in Ohio, weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms, available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters, availability of necessary generating capacity and the performance of our generating plants, our ability to recover I&M's Donald C. Cook Nuclear Plant Unit 1 restoration costs through warranty, insurance and the regulatory process, our ability to recover regulatory assets and stranded costs in connection with deregulation, our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates, our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates, new legislation, litigation and government regulation, including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance, resolution of litigation, our ability to constrain operation and maintenance costs, our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities, changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities, changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP, accounting pronouncements periodically issued by accounting standard-setting bodies, the impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact on future funding requirements, prices and demand for power that we generate and sell at wholesale, changes in technology, particularly with respect to new, developing or alternative sources of generation, other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events, our ability to recover through rates the remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives and evolving public perception of the risks associated with fuels used before, during and after generation of electricity, including nuclear fuel.

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Exhibit JAL-19

Nick Akins, President

Brian Tierney, EVP and CFO

Bette Jo Rozsa, Managing Director IR

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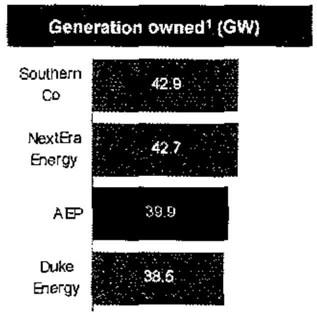
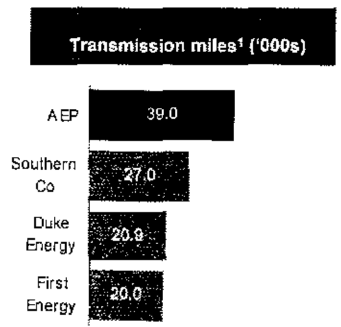
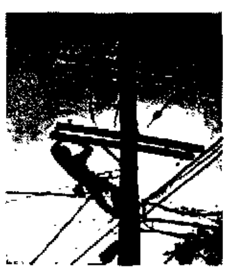
American Electric Power

One of the largest
U.S. electricity generators

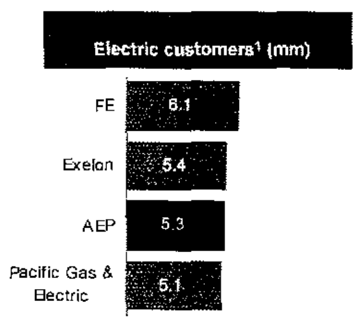


The largest U.S. electricity
transmitter



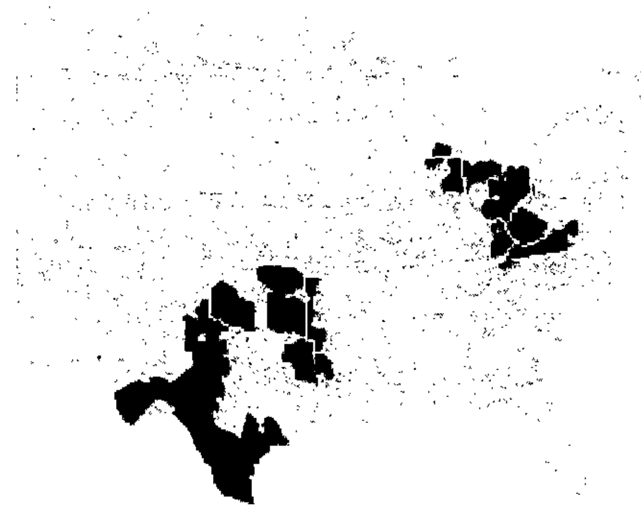


One of the largest U.S.
electricity distributors



1 : Company Filings

Serving electric customers in 11 states



AEP Fast Facts

$14.4B Revenues *
$1.2B Net Income *
10.75% System ROE *

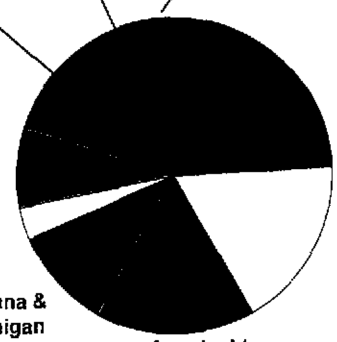
$18.5B Market Capitalization
BBB/Baa2/BBB credit rating

* - represents results for 2010

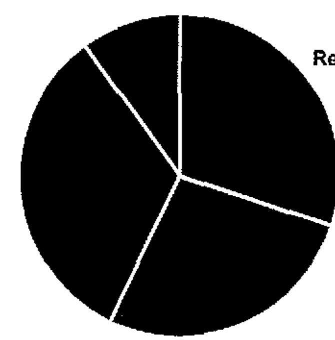
Exhibit JAL-19

Highly Diversified Regulated Utility Platform

2010 On-Going Earnings Contribution



2010 Retail Load



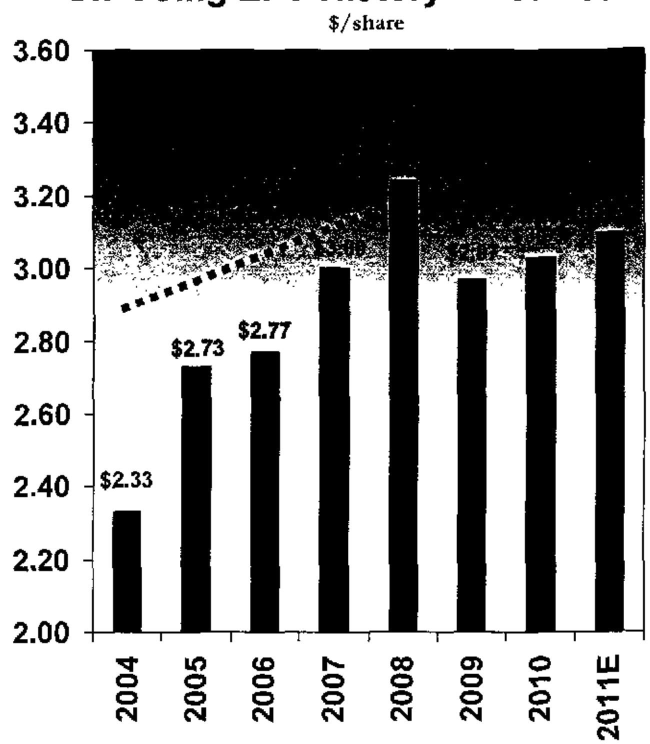
* *Wholesale includes sales to municipal and cooperative power systems, other wholesale, and other retail sales*

Region	# of customers
Appalachian Power (incl. TN)	1,004,000
Indiana & Michigan	582,000
Kentucky Power	174,000
Ohio & Wheeling	1,497,000
PSO (Oklahoma)	532,000
SWEPCO (AR, LA, TX)	520,000
Texas	961,000

Exhibit JAL-19

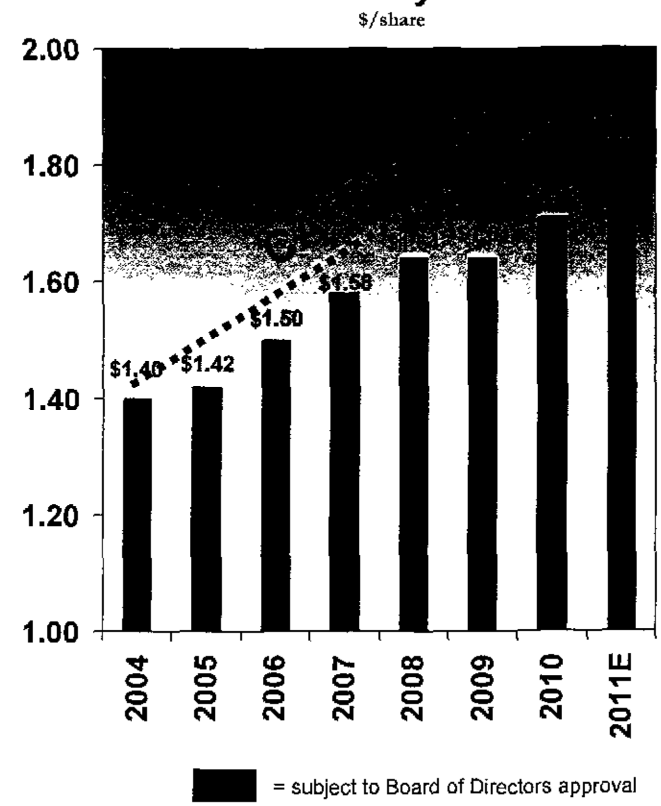
Earnings and Dividends

On-Going EPS History Since 2004



- Earnings growth largely attributed to capital investment program
- Pre-recession earnings supported by robust wholesale market activity and high power prices
- 2011 guidance range of $3.00 to $3.20 per share

Dividend History Since 2004



- Quarterly dividend increased 12% in 2010
- 404th consecutive quarterly dividend paid June 10, 2011
- 50-60% payout ratio target
- Current yield over 4.5%

Exhibit JAL-19

Detailed Ongoing Earnings Guidance

2010A: $3.03

2011E: $3.00 - $3.20

American Electric Power
Financial Results for 2011 Guidance vs 2010 Actual

		2010 Performance Driver	2010 Actual ($ millions)	2011 Performance Driver	2011 Guidance ($ millions)
	UTILITY OPERATIONS:				
	Gross Margin:				
1	East Regulated Integrated Utilities	68,761 GWh @ $ 41.9 /MWhr =	2,882	67,739 GWh @ $ 43.4 /MWhr =	2,940
2	Ohio Companies	49,465 GWh @ $ 56.6 /MWhr =	2,800	49,747 GWh @ $ 56.1 /MWhr =	2,793
3	West Regulated Integrated Utilities	42,131 GWh @ $ 31.4 /MWhr =	1,322	41,536 GWh @ $ 32.8 /MWhr =	1,361
4	Texas Wires	27,348 GWh @ $ 22.3 /MWhr =	611	27,870 GWh @ $ 22.0 /MWhr =	614
5	Off-System Sales	19,172 GWh @ $ 15.6 /MWhr =	299	21,786 GWh @ $ 12.0 /MWhr =	262
6	Transmission Revenue - 3rd Party		369		429
7	Other Operating Revenue		511		481
8	Utility Gross Margin		8,794		8,880
9	Operations & Maintenance		(3,427)		(3,529)
10	Depreciation & Amortization		(1,598)		(1,553)
11	Taxes Other than Income Taxes		(801)		(818)
12	*Interest Exp & Preferred Dividend*		(945)		(921)
13	Other Income & Deductions		154		211
14	Income Taxes		(758)		(787)
15	Utility Operations On-Going Earnings		1,419		1,483
16	Transmission Operations On-Going Earnings		10		17
	NON-UTILITY OPERATIONS:				
17	AEP River Operations		40		51
18	Generation & Marketing		25		6
19	Parent & Other On-Going Earnings		(43)		(61)
20	ON-GOING EARNINGS		1,451		1,496

Exhibit JAL-19

Exhibit JAL-20

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSE TO INDUSTRIAL ENERGY USERS-OHIO'S DISCOVERY REQUEST CASE NOS. 11-346-EL-SSO AND 11-348-EL-SSO FIRST SET

INTERROGATORY

INT-022. Has CSP or OP prepared any estimates of the annual revenues or rates to be collected through the NERC Compliance Rider in 2012, 2013, or 2014?

RESPONSE

No such estimates have been prepared at this time

Exhibit JAL-20

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSE TO INDUSTRIAL ENERGY USERS-OHIO'S DISCOVERY REQUEST CASE NOS. 11-346-EL-SSO AND 11-348-EL-SSO FIRST SET

INTERROGATORY

INT-023 Does CSP or OP have any workpapers or documents to support its calculation of the annual revenues or rates to be collected through the NERC Compliance Rider in 2012, 2013, or 2014? If yes, please identify the documents or workpapers in AEP's possession and the individuals that were responsible for the calculations in those documents or workpapers.

RESPONSE

See IEU INT-022

Exhibit JAL-20

**COLUMBUS SOUTHERN POWER COMPANY'S
AND OHIO POWER COMPANY'S RESPONSE TO
INDUSTRIAL ENERGY USERS-OHIO'S
DISCOVERY REQUEST
CASE NOS. 11-346-EL-SSO AND 11-348-EL-SSO
FIRST SET**

INTERROGATORY

INT-024. If the answer to Interrogatory No 22 is negative, when does CSP and OP plan to provide the rates to be collected through the NERC Compliance Rider in 2012, 2013, and 2014?

RESPONSE

On an annual basis, AEP Ohio will request recovery under the proposed rider of the specific costs incurred during the previous year

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSE TO INDUSTRIAL ENERGY USERS-OHIO DISCOVERY REQUEST CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO SECOND SET

INTERROGATORY

INT-100. In Laura Thomas' testimony at page 26, she provides support for "NERC Generation Compliance Costs".

a. What expenses or capital costs categories does AEP anticipate would be covered by this rider?

b. Does AEP have any expenses or capital costs booked but deferred for this rider?

c. What is the amount of expenses, if any, currently booked but deferred?

d. Over what period of time were expenses or capital costs, if any, booked but deferred? Identify amounts by year.

RESPONSE

a. The Company is unable to determine the exact nature of such costs at this time.

b. No.

c. See IEU INT-100 b.

d. See IEU INT-100 b.

Prepared by: Thomas

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSE TO THE OFFICE OF THE OHIO CONSUMERS' COUNSEL DISCOVERY REQUEST CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO FIRST SET

INTERROGATORY

INT-037. What percentage of the POLR calculated under the Black Sholes model represents:

a. migration risk (i.e the risk that customers will leave the tariffed rates and migrate to a CRES provider—characterized as the put option by AEP Witness Baker in the prior ESP proceeding)?; and,

b the risk of customers returning from CRES service to AEP tariff service (i.e. characterized as the call option by AEP Witness Baker in the prior ESP proceeding)?

RESPONSE

The Company's POLR cost as calculated by the constrained option pricing model was subdivided into the following two cost components:

a. The First-Leave Cost Component - this is the cost of the customers' right to continue to take service at the Company's SSO generation rate until it is in their economic interest to switch to a CRES provider This component accounts for 88% of the Company's POLR cost as calculated by the constrained option pricing model.

b. Additional Cost Beyond The First-Leave Component - this is the value of the customers rights, after the First-Leave scenario, which gives them the right to return to the Company's SSO generation rate, and to continue moving between the Company and a CRES provider, limited only per the currently established switching rules. This component accounts for 12% of the Company's POLR cost as calculated by the constrained option pricing model.

Prepared by: Laura J. Thomas

**COLUMBUS SOUTHERN POWER COMPANY'S
AND OHIO POWER COMPANY'S RESPONSE TO
THE OFFICE OF THE OHIO CONSUMERS' COUNSEL
DISCOVERY REQUEST
CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO
FIRST SET**

INTERROGATORY

INT-020. During the term of the ESP associated with Case No. 08-917-EL-SSO, did AEP Ohio, CSP, or OP individually or AEP buy options or purchase other hedges for the POLR risk that was being faced? Is so, please identify:

a. when such options or hedges were purchased;

b. what the cost of the options or hedges were; and,

c. what period of time was covered by the options or hedges.

RESPONSE

No. The Company effectively self-insured for its POLR risk during term of the ESP associated with Case No. 08-917-EL-SSO.

Prepared by: Laura J. Thomas

Exhibit JAL-23

$ESP = \$69.80$

$$\begin{array}{cccc} & & & \textit{put payout} \\ & & \$90.81 & \$0 \\ & \nearrow & & \\ \$77.72 & & & \\ & \searrow & & \\ & & \$66.51 & \$3.29 \end{array}$$

$\boxed{\text{value of option} = \$1.77}$

- Aggregator can offer customers to split the option premium with the rate payers.
- Say he pays $0.88 to customers for a promise to always pay the ESP price.
- Essentially, aggregator is buying the put option from rate payer at half price.

How does he execute?

- If price goes up to $90.81, customer stays with AEP and put payout = $0.
- If price goes down to $66.51, aggregator serves customer at market and receives $69.80 from customer, put payout = $3.29.
- Aggregator still has risk because his payout is either $-0.88 if price goes up, or $2.41 if price goes down. However, he can remove this risk and guarantee payout = $0.88.

  1. Buy 13.54% of the forward at $77.72, and pays (0.1354)(77.72)=$10.52.
  2. If market price is $91.81, aggregator receives (0.1354)(90.81) = $12.30, payout = (12.30 − 10.52) = $1.77.
  3. If market price is $66.51, aggregator receives (0.1354)(66.51) = $9.00, payout = (9.00 − 10.52) = $ − 1.52.

POLR Cost to AEP

AEP has provided the customer a put option to sell power back to AEP at the ESP price. For the sake of discussion, assume the ESP price is $69.80, the current forward price for power for delivery in May is $77.72, and that the spot price of power for delivery in May will either be $90.51 or $66.51. The spot prices are derived using a Black option tree structure to match the mean and variance of May prices based upon the currently observable forward price, volatility of power prices and interest rates.

AEP's Perspective

If the market price of power is $90.51 in May, the customer's put option is worthless and goes unexercised.

If the market price of power is $66.51 in May, the customer exercises the put option to sell power to AEP. The customer sells power to AEP at $69.80. AEP must flatten the position by selling power at the market price of $66.51, for a loss to AEP of $3.29.

Thus, AEP has an uncertain outcome: Either there will be no loss or a loss of $3.29, depending on market prices.

Removing the Uncertainty

To eliminate the variability in the payment of the customer's put option, in this case, AEP can sell May power forward at $77.72 for 13.54% of the volume.

If the market price of power is $90.51, AEP receives: 0.1354*$77.72 = $10.52.
To flatten the power position, AEP pays the market price for the power: 0.1354*$90.51 = $12.30. The associated power forward sale and spot purchase costs AEP $1.78 in May. When added to the payout for the unexercised put option, AEP loses $1.78 in May.

If the market price of power is $66.51, AEP receives: 0.1354*$77.72 = $10.52.
To flatten the power position, AEP pays the market price for power: 0.1354*$66.51 = $9.01, for a gain of $1.51 in May. However, AEP has to pay out the $3.29 for the in-the-money put option, for a net loss of $1.78 in May.

Under either market condition, AEP loses $1.78 in May. To be made whole, AEP should be compensated for this $1.78 cost.

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSES TO EXELON GENERATION COMPANY, LLC'S DISCOVERY REQUEST CASE NOS. 11-346-EL-SSO AND 11-348-EL-SSO FOURTH SET

INTERROGATORY

INT-5-060. Has AEP Ohio conducted any studies that measure the actual cost of migration during calendar years 2009, 2010 or 2011?. If so, please provide all such studies, regardless of whether they are of an individual or of a group of customers. For each such study, please provide the following: 1) the subject of the study; 2) the result and conclusion of the study; and 3) the methodology applied in the study

RESPONSE

The Company objects to this request as being vague, overbroad and unduly burdensome, especially with respect to the terms "cost" and migration." Without waiving these objections or any general objection the Company may have, the information referenced below is refernced based on a good faith search and using the Company's understanding of the question. The Company has not performed any studies quantifying after-the-fact cost. See pages 13-22 of the direct testimony of Company witness Thomas regarding the cost of migration risk. Also see the Company's responses to OCC INT-037, OCC INT-168 and FES INT-037.

Prepared By: Laura J. Thomas

Exhibit JAL-25

**COLUMBUS SOUTHERN POWER COMPANY'S
AND OHIO POWER COMPANY'S RESPONSE TO
FIRSTENERGY SOLUTIONS
DISCOVERY REQUEST
CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO
NINTH SET**

INTERROGATORY

INT-9-010 During American Electric Power's April 21, 2011 Earnings Call, AEP's CEO Mike Morris stated: "You may remember also that the Supreme Court said that it's kind of difficult to understand this [POLR cost formula] because American Electric Power hasn't incurred any lost load or customers switching. Well clearly, that's the case today. So we think there's plenty of room on remand for the Commission to satisfy that if they'd like. If they want to go the other side and have a detailed cost demonstration of what it takes to keep units always ready to run whenever people come back, we'll be happy to do that." Please identify Your cost demonstration of what it takes to keep units always ready to run whenever people come back.

RESPONSE

Without agreeing or disagreeing that the statement is an accurate quote, no such analysis has been performed

Prepared By: Counsel/ Laura J. Thomas

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSE TO INDUSTRIAL ENERGY USERS-OHIO DISCOVERY REQUEST CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO SECOND SET

INTERROGATORY

INT-081. Regarding the Carbon Capture and Sequestration ("CCS") facility being developed at Appalachian Power Company's Mountaineer plant site that AEP is seeking to collect costs from Ohio retail customers, identify whether the CCS project will create any jobs or economic benefits in Ohio.

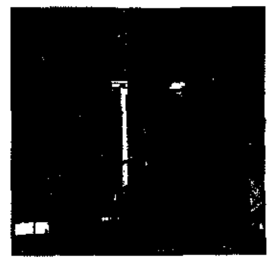
RESPONSE

While the Company does not possess specific information with respect to jobs and economic benefits, the Mountaineer Plant's proximity to Ohio is likely to provide job opportunities and economic benefits to the state.

Prepared by: Nelson

Cost and Reliability Impacts of Pending EPA Regulations

Bruce Braine
Vice President, Strategic Policy Analysis



MIT-CEEPR Workshop
May 5, 2011

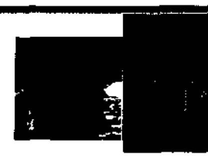
AEP AMERICAN ELECTRIC POWER

AEP - Background

Coal/Lignite
66%

Gas/Oil
22%

Nuclear
6%



Pumped Storage/ Hydro/Wind
6%

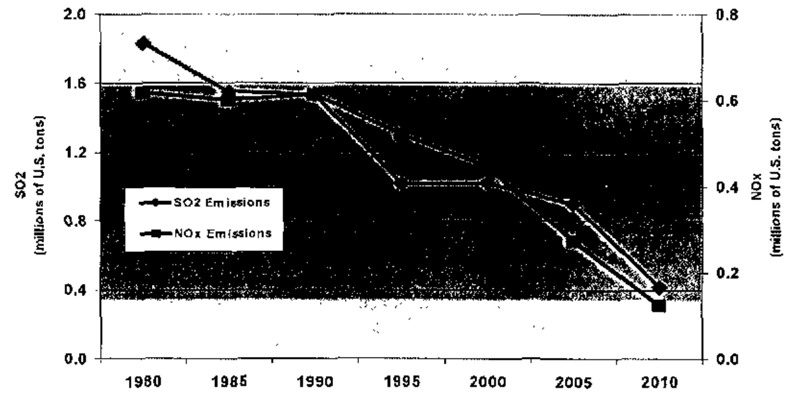
AEP's Generation Fleet
~39,000 MW Capacity
~80% of coal is in AEP-East

5.2 million customers in 11 states
Industry-leading size and scale of assets:

Asset	Size	Industry Rank
Domestic Generation	~39,000 MW	# 2
Transmission	~39,000 miles	# 1
Distribution	~214,000 miles	# 1

AEP AMERICAN ELECTRIC POWER

AEP Already Has Substantially Reduced SO_2 & NOx Emissions



- *Since 1980 AEP's TOTAL generating fleet has <u>reduced</u>:*
  - *SO_2 emissions by <u>over 77%</u>*
  - *NOx emissions by <u>~80%</u>*

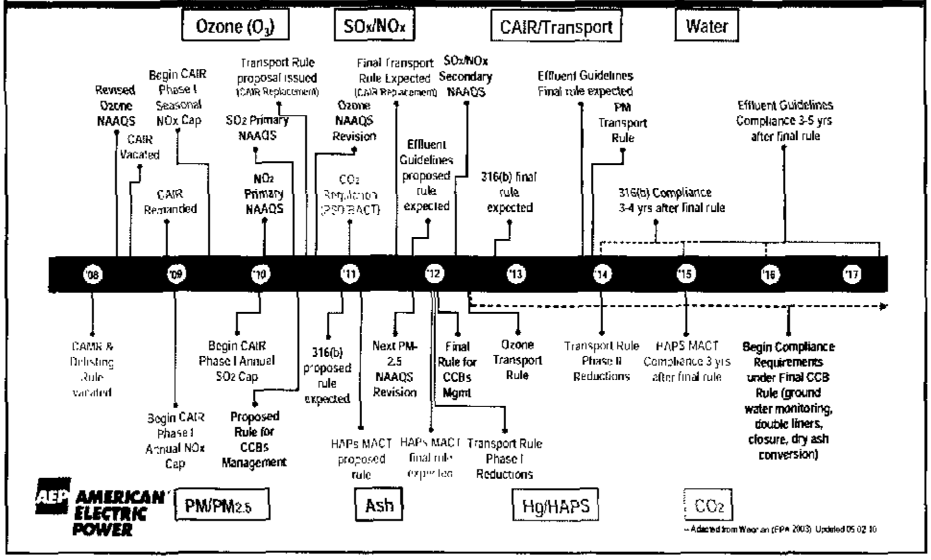
AEP AMERICAN ELECTRIC POWER

EPA New Regulatory Challenges

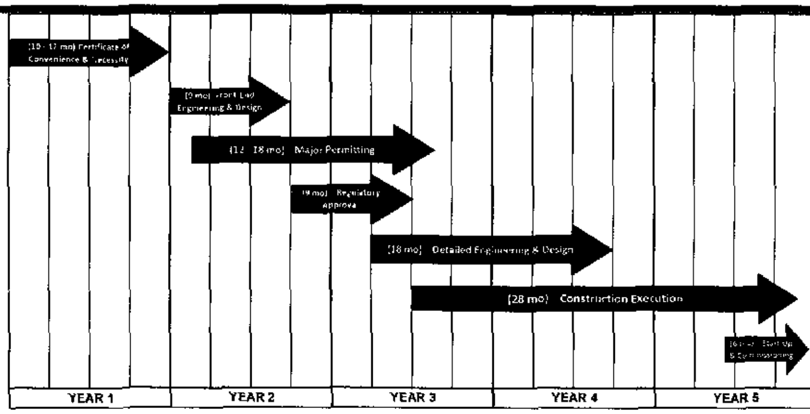
- *Climate Regulations (NSPS & NSR)*
- *Transport Rule (SO_2 & NOx)*
- *Mercury/Hazardous Air Pollutants (HAPs)*
- *Coal Combustion Residuals (CCR)*
- *Water Quality / Aquatic Impacts (316(b))*

AEP AMERICAN ELECTRIC POWER

Possible Timeline for Environmental Regs for Electric Utilities



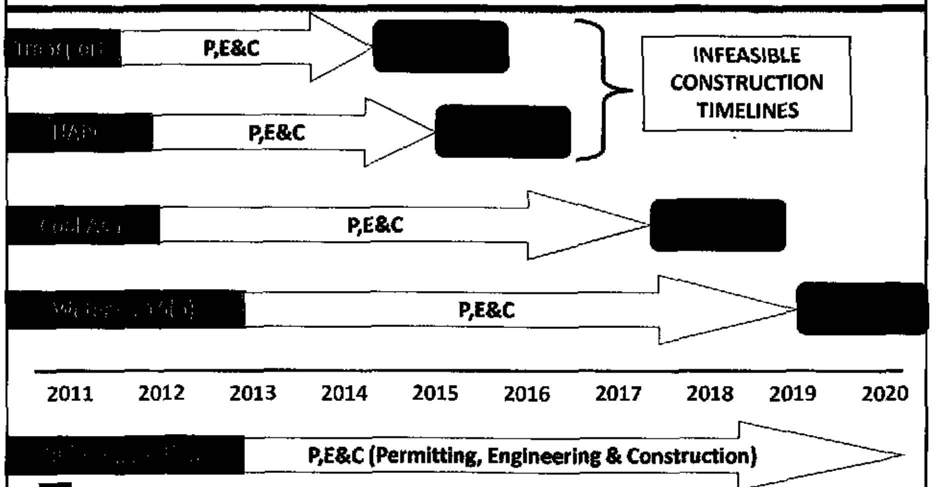
Typical AEP FGD Retrofit Timeline



- *Timeline milestone lengths based on actual AEP construction experience*
- *Phases could be longer if the support system becomes strained from multiple companies facing similar compliance deadlines*
- *From 2003-10 AEP retrofitted 7,800 MWs (9 units), using over 35 million work hours at a cost of over $3.6 billion*

AMERICAN ELECTRIC POWER

Anticipated EPA Timeline for Retrofits or Replacement



AMERICAN ELECTRIC POWER

"The Nightmare on Utility Street?"

- ***<u>Transport Rule</u>***
  - ***SO_2 and NOx caps in 2012, tighter SO_2 caps in 2014***
  - ***FGD effectively "required" for most all AEP East units in 2014***
- ***<u>Mercury and Other HAPs MACT Rules</u>***
  - ***Compliance in 3 years = 1/2015 (or 1/2016 "case by case")***
  - ***FGD for acid gases likely required on most AEP-East units***
  - ***Baghouses (BH) w/ activated carbon injection (ACI) COULD ALSO be required to meet Hg and heavy metal limits***
  - ***Some AEP-West coal units may be able to comply with only BH and ACI; however other EPA requirements (CAVR) likely to force scrubbers at most units***
- ***<u>CCR Rule (e.g. ash disposal)</u>***
  - ***Compliance estimated by 2017***
  - ***AEP capital + pond closure cost: $1.4-2.4 billion if "non-hazardous"***
  - ***Costs DOUBLE with "hazardous" designation by EPA***

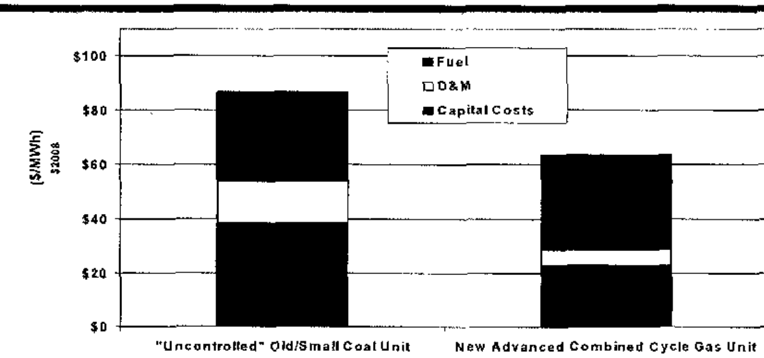
AMERICAN ELECTRIC POWER

Major AEP Impacts of Pending and New EPA Regulations

- *Large Amount of AEP Coal Unit Retirements*
  - *5 to 7 GW retired (~20-30% of AEP total capacity) by 2014-2015*
  - *Coal units potentially mothballed 2014-2016*
- *Capital Cost: $6 to 11 billion by 2020*
  - *As much as DOUBLE AEP Environmental Capital spend during last 20 years*
- *Ongoing additional O&M, fuel and purchased power expenses of $300 to 600 million per year*
  - *NPV cost of about $2 to $4 billion*
- *Large Electricity Rate Increases*
  - *Average of 20 to 30% across AEP system*

AEP AMERICAN ELECTRIC POWER

Old/Small Units Very Likely to Retire by 2015 Under EPA Regulations



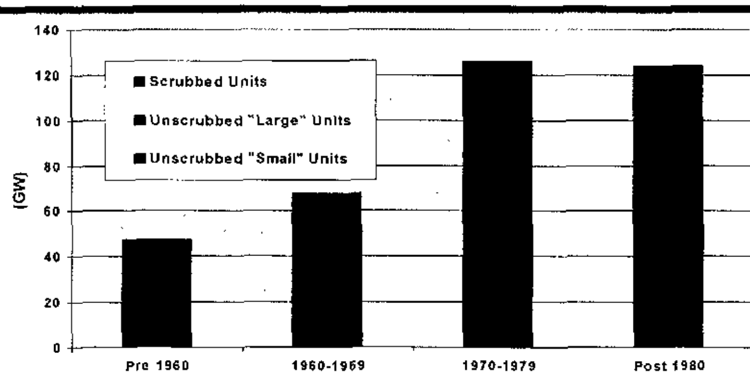
Assumptions

- *Retrofit and New Build capital cost & O&M assumptions are from EPA estimates*
- *Coal Combustion Residuals (CCR) capital cost is from industry estimates*
- *Uncontrolled Coal Unit (300 MW) Requires FGD+SCR+CCR: Capital Cost ~$1,200//kW; Retrofit Life - 15 years; 11,000 Btu/kWh Heat Rate, $2.50/MMBtu Coal Price*
- *Gas Combined Cycle: Capital Cost - $1000/kW; Life - 30 years; 7,000 Btu/kWh Heat Rate, $5/MMBtu Gas Price*

AEP AMERICAN ELECTRIC POWER

Exhibit JAL-27

U.S. Coal Fired Generating Capacity



Source: Energy Velocity Suite Data

- ~75 GW BOTH unscrubbed AND >45 years old by 2015
- ~54 GW also "SMALL" - Almost ALL will retire by 2015 w/ EPA regs.

AEP AMERICAN ELECTRIC POWER

ICF-EEI Study Results: Large US & Regional Cost Impacts

	2010 Coal Capacity	"Optimistic" Case Retirements	"Pessimistic" Case Retirements
Total U.S. Coal (GW)	324	-46	-101
SERC Coal (GW)	100	-17	-41
RFC Coal (GW)	105	-16	-29
U.S. Incremental Capital (2012-2020) ($Billions)		141	247

"2010 Coal Capacity" Source: Ventyx Velocity Suite

- *ICF-EEI study first to assess impact of ALL new EPA rules*
- *Range of impacts from Run #3 (optimistic) to # 8 (pessimistic)*
- *ICF-EEI study "conservative" on retirements: (1) high gas prices (2) long 20 year life for retrofits (3) assumes retrofits can be done by 2015 (4) low end of range assume NO CO2 requirements*
- *Capital (most before 2015) more than DOUBLE U.S. electric industry environmental capital spend during 1991-2010*

AEP AMERICAN ELECTRIC POWER

Reliability Impacts of EPA Regulations on RFC / PJM

- *RFC estimated to have between 16 and 29 GW of coal retirements, or about 15 to 25 percent of RFC coal, most occurring by 2015*
- *Also, substantial % of capacity will be retrofit in RFC over the exact same time period*
- *Retrofits often requires a plant to be taken offline at end of construction for 2-3 months*
- *AEP is likely to mothball some additional capacity during the 2014-16 in order to complete retrofits and continue to comply with MACT and Transport Rules*
- *PJM analysis will be required to determine if this poses any regional reliability problems*

AEP AMERICAN ELECTRIC POWER

Local Reliability Impacts

- *Almost all of AEP retirements will be subcritical coal units, which are located in the middle of the supply stack, and thus are "load following"*
- *These units often provide key ancillary services:*
  - *Voltage Support*
  - *Frequency Regulation*
  - *System Restoration*
- *Local transmission mitigation and local system restoration capability/capacity will need to be installed prior to unit retirements to ensure grid integrity*
- *Timing of EPA regulations NEEDS to be coordinated with time required to address these local issues*
- *Further PJM, SERC and other regional study is needed on this issue and potentially affected facilities*

AEP AMERICAN ELECTRIC POWER

Other Economic Impacts of EPA Regulations

- *Higher natural gas use and related price increases affects ALL consumers*
- *$0.50/MMBtu gas price change increases other consumer costs about $8-9 billion/year*
- *Net Job Impacts are Negative:*
  - *Near term increases in temporary (2-5 years) construction jobs*
  - *BUT, "NET" NEGATIVE for Total Jobs mostly due to large electricity price increases*
    - *CRA Testimony --- NET LOSS of 1 MM Jobs*
    - *ERRC Testimony --- NET LOSS of 2.5 MM Jobs*
  - *'Green jobs' studies such as PERI study don't consider big negatives of higher electricity & energy prices*

AEP AMERICAN ELECTRIC POWER

There is a Better Way...

- *More flexibility in regulations (e.g., HAPs emissions averaging, low capacity factor allowed during retrofit construction)*
- *Phase-in requirements over 2015-2020*
- *Allow off-ramp for units that commit to retire or repower through 2020*
- *Continues emission reduction progress starting today, but reduces capital cost, rate shock and other economic impacts*
- *All coal units "well controlled" by 2020*

AEP AMERICAN ELECTRIC POWER

American Tradition Institute

Exhibit JAL-28

The Cost and Economic Impact of Ohio's Alternative Energy Portfolio Standard

AMERICAN TRADITION INSTITUTE
Washington, D.C. • Raleigh • Denver • Bozeman

2020 PENNSYLVANIA AVENUE NW #186
WASHINGTON D.C. 20006

APRIL 2011

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Executive Summary

Ohio enacted its Alternative Energy Portfolio Standard (AEPS) legislation in May 2008. The law requires one-quarter of all electricity sales by Ohio utilities to come from "alternative energy" sources by the year 2025, with 12.5 percent required to come from sources identified as "renewable." While the law includes a provision cap electricity costs due to the mandate, it is unlikely that the cap would be breached due to its structure.

The American Tradition Institute commissioned the Beacon Hill Institute to apply its STAMP® (State Tax Analysis Modeling Program) to estimate the economic effects of the AEPS mandate. To account for excessively optimistic Energy Information Administration (EIA) measures of renewable electricity costs and capacity factors, we reviewed academic literature to provide three estimates of the cost of Ohio's AEPS mandates — low, average and high — using different cost and capacity factor estimates for electricity-generating technologies. Major cost findings include:

- The state's electricity consumers will pay $1.427 billion more for power in 2025, within a range of $262 million and $2.373 billion, because of the AEPS.
- Over the period of 2016 to 2025, Ohioans will pay an additional $8.629 billion over a baseline of no AEPS, within a range of $5.22 billion and $10.929 billion.
- Ohio's electricity prices in 2025 will increase by an average of 9.3 percent, within a range of 1.7 percent and 15.4 percent.

These increased energy prices will hurt Ohio's households and businesses and thus impair the state economy. According to the study, by 2025:

- Ohio will lose an average of 9,753 jobs, within a low-end estimate of 2,480 jobs and a high-end estimate of 15,523 jobs.
- The AEPS will reduce annual wages by an average of $334 per worker, within a range of $61 per worker and $556 per worker.
- Real disposable income will fall by $1.097 billion, within a range of $201 million and $1.824 billion.
- Net investment will fall by $79 million, within a range of $15 million and $132 million.
- The policy will cost families on average $123 per year, commercial businesses on average $867 per year, and industrial businesses on average $31,024 per year.
- From 2016 to 2025 the average household ratepayer will pay $756 in higher electricity costs; the average commercial ratepayer will pay an extra $5,350; and the average industrial ratepayer an extra $191,490.

Introduction

Beginning in May 2008, with the passage of Senate Bill 221, Ohio lawmakers began to dictate the generation technologies that utilities must use to produce the electricity sold in the state. The state passed an Alternative Energy Portfolio Standard (AEPS) that included a Renewable Portfolio Standard (RPS) and an Advanced Energy Sources (AES) requirement.

The RPS requires an increasing share of all retail electricity sold in Ohio to come from renewable sources, including solar, wind, biomass, geothermal, solid waste and hydroelectric facilities. Specifically, the law requires that beginning in 2009 at least 0.25 percent of all retail electricity sales derive from a renewable source. The share increases each year until it reaches 12.5 percent in 2025.[1] The RPS includes a provision requiring 0.5 percent of Ohio's total electricity supply derive from solar energy.[2] Moreover, half of all renewable energy production under the mandate, including solar, must be located in the state of Ohio.

The AES calls for an equal share of energy to be produced by 'Advanced Energy Sources', as has to be produced by the RPS, or 12.5 percent by 2025. AES are defined as nuclear, clean coal, fuel cells, any modification to current electric generating facilities that increases output but not emissions and demand side management practices. The AES does not contain any intermediate benchmarks prior to 2025.

The law includes cost containment provisions. Should a utility determine that their cost to comply with the AEPS would raise the price of electricity to all consumers by more than 3 percent, the utility can petition the Ohio Public Utility Commission (PUC) for a waiver. The AEPS also contains a force majeure provision that allows for non-compliance if circumstances are beyond the control of the utility. The law specifically places the burden of proof on the utility, to prove that after subtracting "unavoidable surcharge for construction or environmental expenditures of generation," the cost of generating electricity under the AEPS will be 3 percent more than without complying with the mandate.[3] However, since the law contains annual increases in the mandate, it allows the electricity costs due to the mandate to rise by 3 percent per year. Thus, the provision effectively allows electricity prices to rise by 60.5 percent between 2008 and 2025 due to the AEPS compliance costs. Furthermore the cost cap excludes the "unavoidable surcharge" in the calculation of AEPS costs, but includes them in the calculation of the non-compliance cost scenario, in effect pushing down the cost of compliance. These two factors render the cost control components of the AEPS ineffective and meaningless.

Most renewable electricity sources are more costly and unreliable than conventional energy sources such as coal and natural gas, and stand little chance of commercial success in a

[1] Ibid.
[2] Ibid. Also U.S. Energy Information Administration. Ohio Renewable Energy Profile. http://www.eia.gov/cneaf/solar.renewables/page/state_profiles/ohio.html.
[3] Ibid.

competitive market. In response, producers of renewable energy seek to guarantee a market through legislation similar to the AEPS. But whatever the market offers in terms of renewable energy, it will always be limited. In order to keep the electricity grid in equilibrium, intermittent resources such as wind and solar power need reliable back-up sources. If the wind dies down, or blows too hard (which trips a shutdown mechanism in commercial windmills), another power source must be ramped up instantly.

Not unlike taxes, higher electricity prices produce negative effects on economic activity, since one is paying a higher price for electricity without an increase in the value of that electricity. Prosperity and economic growth depend upon access to reliable and competitively priced energy. Consumers will have limited opportunity to avoid these costs. For low-income consumers, these higher electricity prices will force difficult choices between energy and other necessities such as such as clothing and shelter.

In this report, the American Tradition Institute commissioned the Beacon Hill Institute (BHI) to estimate the costs of the AEPS mandate and the economic impact of the legislation on the state economy. To that end, BHI applied its STAMP® models (State Tax Analysis Modeling Program) to estimate the economic effects of the state AEPS mandate.

Results

A wide variety of cost estimates exist for renewable electricity sources. The U.S. Energy Information Administration (EIA), a division of the Department of Energy, provides estimates for the cost of conventional and renewable electricity generating technologies. A literature review shows that in most cases the EIA's projected costs are at the low end of the range of estimates while the EIA's capacity factor for wind to be at the high end of the range.[4] The EIA appears to overlook the actual experience of existing renewable electricity power plants.

In measuring the effects of the AEPS on the Ohio economy, we account for the effects of the RPS and AES. The RPS mandate increases by 0.25 percent per year until it reaches 12.5 percent in 2025, which we calculate the cost for each year from 2016 to 2025. The AES does not ramp up similarly; it simply requires 12.5 percent of all electricity be produced from advanced energy sources by 2025. Due to the costs and lead times associated with implementation of AES, such as clean coal and nuclear, we follow the letter of the law and assume that the generation units are completed in 2025, when the full 12.5 percent is implemented.[5] We also assume the AES mandate is satisfied through clean coal and nuclear power generation, since these are the only sources that can produce electricity in industrial quantities.

[4] The capacity factor measures the ratio of electrical energy produced by a generating unit over a period of time to the electrical energy that could have been produced at 100 percent operation during the same period.
[5] Details on the methodology used can be found in the Appendix.

In light of the wide divergence in the costs and capacity factor estimates available for the different electricity generation technologies, we provide three estimates of the effects of Ohio AEPS mandate using low, average and high cost projections of both renewable and conventional generation technologies. Each estimate represents the change that will take place in the indicated variable against the assumption that the AEPS mandate would not be implemented. The Appendix details our methodology. Table 1 displays our estimates.

Table 1: The Cost of the AEPS Mandate on Ohio (2010 $)

Costs Estimates	**Low**	**Medium**	**High**
Total Net Cost in 2025 ($ m)	262	1,427	2,373
Total Net Cost 2016-2025 ($ m)	5,220	8,629	10,929
Electricity Price Increase in 2025 (cents per kWh)	0.18	0.97	1.61
Percentage Increase	1.7%	9.3%	15.4%
Economic Indicators			
Total Employment (jobs)	(2,480)	(9,753)	(15,523)
Gross Wage Rates ($ per Worker)	(61)	(334)	(556)
Investment ($ m)	(15)	(79)	(132)
Real Disposable Income ($ m)	(201)	(1,097)	(1,824)

The results for the low cost scenario are substantially lower than the other two. This divergence is primarily due to the EIA's projections that costs of nuclear and clean coal will fall dramatically over the next 15 years. See Table 5 in the Appendix. The AEPS will impose costs of $1.427 billion in 2025, within a range of $262 million and $2.373 billion. For the period of 2016 – 2025 the AEPS mandate will cost $8.629 billion, with a low estimate of $5.22 billion and a high estimate of $10.929 billion. As a result, the AEPS mandate will increase electricity prices by 0.97 cents per kilowatt-hour (kWh), or by 9.3 percent, within a range of 0.18 cents per kWh, or by 1.7 percent, and 1.61 cents per kWh, or by 15.4 percent.[6]

Upon full implementation, the AEPS law will reduce economic output in Ohio. Ratepayers will face higher electricity prices, which will increase the cost of living and the cost of doing business in the state. By 2025 Ohio will employ 9,753 fewer workers than without the AEPS policy, within an estimated range of 2,480 and 15,523 workers.

The decrease in labor demand — as seen in the job losses — will cause gross wages to fall. In 2025 the Ohio AEPS will reduce annual wages by $334 per worker, within a range of $61 and $556 per worker.

[6] We converted the aggregate cost of the RPS into a cost per-kWh by dividing the cost by the estimated total number of kWh sold for that year. For example, for 2025 under the average cost scenario above, we divided $1,427 million into 147,058 million kWhs for a cost of 0.97 cents per kWh.

The job losses and price increases will reduce real incomes as firms, households and governments are forced to allocate more resources to purchase electricity and less to purchase other items. In 2025 annual real disposable income will fall by $1.097 billion, within a range of $201 million and $1.824 billion under our low and high cost scenarios respectively.

Net investment will fall by $79 million in 2025, within a range of $15 million and $132 million. The relatively moderate investment losses will be offset by the investments required to build renewable power plants, transmission lines and reconfigurations to the electricity grid. However, these investments are not as productive as the ones based on conventional energy because the renewable mandate works its way through the production methods less efficiently. A good analogy would be applying a mandate to telecommunications. An AEPS is akin to requiring that 25 percent of all Internet access to comprise of dial-up service over telephone service lines. Business would indeed be good for dial-up modem manufacturers, and Internet Service Providers would need to retrofit their networks, but this investment would not increase productivity in the economy.

Table 2 shows how the AEPS will affect the annual electricity bills of households and businesses in Ohio. In 2025 the AEPS will cost families on average $123 per year; commercial businesses on average of $867 per year; and industrial businesses on average $31,024 per year. Between 2016 and 2025 the average household ratepayer will pay $756 in higher electricity costs; the average commercial ratepayer will spend an extra $5,350; and the average industrial ratepayer an extra $191,490.

Table 2: Effects of the AEPS on Electricity Ratepayers (2010 $)

Cost in 2025	**Low**	**Medium**	**High**
Residential Ratepayer ($)	22	123	204
Commercial Ratepayer ($)	159	867	1,441
Industrial Ratepayer ($)	5,695	31,024	51,596
Total over period (2016-2025)			
Residential Ratepayer ($)	402	756	1,013
Commercial Ratepayer ($)	2,841	5,350	7,166
Industrial Ratepayer ($)	101,685	191,490	256,507

One could justify the higher electricity costs if the environmental benefits, in terms of reduced GHG emissions, outweighed the costs. But it is unclear that the use of renewable energy resources, especially wind and solar, significantly reduces GHG emissions. Due to their intermittency, wind and solar require significant backup power sources that are cycled up and down to accommodate the variability in their production. As a result, wind power could actually increase pollution and greenhouse gas emissions, according to a recent study.[7] Thus the case for the heavy use of wind to generate "cleaner" electricity is undermined.

[7] See "How Less Became More: Wind, Power and Unintended Consequences in the Colorado Energy Market," BENTEK Energy, LLC. (Evergreen Colorado: May, 2010).

Conclusion

The rush to renewable energy found in AEPS mandates in states across the nation is flawed. The policy promotes certain forms of renewable energy — expensive ones — at the cost of other, more affordable and dependable sources. The Ohio law is no different. On the surface, the cost caps included in the Ohio law appear reasonable. However, a detailed examination reveals that the cost cap provision will allow Ohio's electricity prices to rise by 65.5 percent due to the AEPS. The cost caps will not protect electricity ratepayers from higher utility prices or the state economy from employment losses, diminished investment, and lower incomes. Moreover, the environmental benefits of wind and solar power are illusionary since both forms of energy require readily available backup power generation sources.

The Ohio AEPS law requires the state's Public Utilities Commission to file an annual compliance report that includes a section pertaining to "any strategy for utility and company compliance or for encouraging the use of alternative energy resources in supplying this state's electricity needs in a manner that considers available technology, costs, job creation, and economic impacts."[8] The evidence presented in this report shows that the impacts are decidedly negative.

The Ohio AEPS puts the state's competitiveness at risk. These costs will result in slower economic growth for Ohio in the future, and it will fall behind competitor states. Policymakers should pay careful attention to the real dangers posed by higher electricity prices and repeal the mandate at the first opportunity. At the very least, lawmakers should amend the law to require the PUC annual compliance report to include a cost/benefit analysis section.

[8] Ohio Revised Code, Title [49] XLIX PUBLIC UTILITIES, » Chapter 4928: COMPETITIVE RETAIL ELECTRIC SERVICE, paragraph D1, http://codes.ohio.gov/orc/4928.64 (accessed February 15, 2011).

Appendix

Electricity Generation Costs

As noted above, governments enact Renewable Portfolio Standard policies because most sources of renewable electricity generation are less efficient and thus more costly than conventional sources of generation. The RPS policy forces utilities to buy electricity from renewable sources and thus guarantees a market for the renewable source. These higher costs get passed on to all electricity consumers: residential, commercial and industrial.

The U.S. Department of Energy's Energy Information Administration (EIA) estimates the Levelized Energy Cost (LEC), or financial breakeven cost per MWh, to produce new electricity in its *Annual Energy Outlook*.[9] The EIA provides LEC estimates for conventional and renewable electricity technologies (coal, nuclear geothermal, landfill gas, solar photovoltaic, wind and biomass) assuming the new sources enter service in 2016. The EIA also provides LEC estimates for conventional coal, combined cycle gas, advanced nuclear and onshore wind only, assuming the sources enter service in 2020 and 2035.

While the EIA does not provide LEC for hydroelectric, solar photovoltaic and biomass for 2020 and 2035, it does project overnight capital costs for 2015, 2025 and 2035. We can estimate the LEC for these technologies and years using the percent change in capital costs to inflate the 2016 LECs. In its *Annual Energy Outlook*, the EIA incorporates many assumptions about the future price of capital, materials, fossil fuels, maintenance and capacity factor into their forecast. Table 3 on the following page shows over time the EIA projects that the LEC for all four electricity sources (coal, gas, nuclear and wind) fall significantly from 2016 to 2035. The fall in capital costs drives the drop in total system LEC over the period.

The EIA estimates that wind generation will benefit from lower transmission and maintenance costs. EIA forecasts that transmission costs for wind will drop from $8.4 per MWh in 2016 to $5.6 per MWh, or by 33 percent, between 2020 and 2035. Fixed operations and maintenance costs will drop from $11.4 per MWh to $8.9 per MWh, or by 22 percent, over the same period. The drop in capital, maintenance and transmission costs combine to reduce wind power cost from $149.3 per MWh to $78.9 per MWh, or by an astounding 47.2 percent over the period. By 2035, wind would become the third least expensive behind biomass and natural gas.

[9] U.S. Department of Energy, Energy Information Administration, *2016 Levelized Cost of New Generation Resources from the Annual Energy Outlook 2010* (2008/$MWh), http://www.eia.doe.gov/oiaf/aeo/electricity_generation.html (accessed September 20, 2010).

Table 3: Levelized Cost of Electricity from Conventional and Renewable Sources (2008 $)

Plant Type	Capacity Factor	Levelized Capital Costs	Fixed O&M	Variable O&M (with fuel)	Transmission Investment	Total Levelized Cost
Advanced Coal - 2016	0.850	81.2	5.3	20.4	3.6	110.5
2020		77.1	5.3	19.6	3.6	105.6
2035		55.9	5.3	20.2	3.5	84.9
Gas - 2016	0.870	22.9	1.7	54.9	3.6	83.1
2020		21.4	1.6	53.7	3.6	80.3
2035		15.6	1.6	54	3.7	74.9
Nuclear -2016	0.900	94.9	11.7	9.4	3.0	119.0
2020		86.9	11.7	9.9	3.0	111.5
2035		60.9	11.7	11.6	3.0	87.2
Wind - 2016	0.344	130.5	10.4	0.0	8.4	149.3
2020		81.6	8.9	0.0	5.6	96.1
2035		64.4	8.9	0.0	5.6	78.9
Solar PV - 2016	0.217	376.8	6.4	0.0	13.0	396.1
2025						297.7
2035						208.6
Biomass -2016	0.830	73.3	9.1	24.9	3.8	111.1
2025						62.8
2035						47.5
Hydro -2016	0.514	103.7	3.5	7.1	5.7	119.9
2025						101.3
2035						83.4

Using the EIA change in overnight capital costs for solar and biomass produces reductions in LECs similar to wind from 2016 to 2035. The biomass LEC drops by 57.3 percent and solar by 47.3 percent over the period. These compare to much more modest cost reductions of 23.1 percent for coal, 9.9 percent for gas, and 26.7 percent for nuclear over the same period. EIA does provide overnight capital costs for renewable technologies under a "high cost" scenario. However, for each renewable technology the EIA "high cost" scenario projects capital costs to drop between 2015 and 2035.

Moreover the building of vast wind power plants will require large quantities of raw materials, particularly aluminum and other commodities. The rising demand for these commodities – from the construction of renewable energy plants and from fast growing emerging market economies – will certainly increase their prices and therefore costs for wind power plants. Aluminum prices have doubled over the past two years as the world economy struggles to emerge from the recession.[10] As a result capital and other costs are more likely to rise than fall over the next two decades.

Table 3 also displays capacity factors for each technology. The capacity factor measures the ratio of electrical energy produced by a generating unit over a period of time to the electrical energy that could have been produced at 100 percent operation during the same period. In this case, the capacity factor measures the potential productivity of the generating technology. Solar, wind and hydroelectricity have the lowest capacity factors due to the intermittent nature of their power sources. EIA projects a 34.4 percent capacity factor for wind power, which, as we will see below, appears to be at the high end of any range of estimates.

Estimating a capacity factor for wind power is particularly challenging. Wind is not only intermittent but its variation is unpredictable, making it impossible to dispatch to the grid with any certainty. This unique feature of wind power argues for a capacity factor rating of close to zero. Nevertheless, wind capacity factors have been estimated to be between 20 percent and 40 percent.[11] The other variables that affect the capacity factor of wind are the quality and consistency of the wind and the size and technology of the wind turbines deployed. As the U.S. and other countries add more wind power over time, presumably the wind turbine technology will improve, but the new locations for wind power plants will likely have diminishing or less productive wind resources.

The EIA estimates of LEC and capacity factors paint a particularly rosy view of the future cost of renewable electricity generation, particularly wind. Other forecasters and the experience of current renewable energy projects portray a less sanguine outlook.

Today wind and biomass are the largest renewable power sources and are the most likely to satisfy future RPS mandates. The most prominent issues that will affect the future availability and cost of renewable electricity resources are diminishing marginal returns and competition for scarce resources. These issues will affect wind and biomass in different ways as state RPS mandates ratchet up over the next decade.

Both wind and biomass resources face land use issues. Conventional energy plants can be built within a space of several acres and can be located close to large population centers with high electricity demand. However, a wind power plant with the same nameplate capacity (not actual capacity) would require many square miles of land. According to one study, wind power would require 7,579 miles of mountain ridgeline to satisfy current state RPS mandates

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[10] MetalPrices.com, "LME Aluminum Price Charts," http://www.metalprices.com/FreeSite/metals/al/al.asp#MoreCharts (accessed January 2011).
[11] Renewable Energy Research Laboratory, University of Massachusetts at Amherst, "Wind Power, Capacity Factor and Intermittency: What Happens When the Wind Doesn't Blow?" Community Wind Power Fact Sheet #2a, http://www.ceere.org/rerl/about_wind/RERL_Fact_Sheet_2a_Capacity_Factor.pdf (accessed December, 2010).

and a 20 percent federal mandate by 2025.[12] Mountain ridgelines produce the most promising locations for electric wind production in the eastern and far western United States.

After taking into account capacity factors, a wind power plant would need a land mass of 20 by 25 kilometers to produce the same energy as a nuclear power plant that can be situated on 500 square meters.[13]

The need for large areas of land for situating wind power plants will require the purchase of vast areas of land by private wind developers and/or allowing wind production on public lands. In either case land acquisition/rent or public permitting processes will likely increase costs as wind power plants are built. Offshore wind is vastly more expensive than onshore wind power and suffers from the same type of permitting process faced by onshore wind power plants, as seen in the 10-year permitting process for the planned Cape Wind project off the coast of Massachusetts.

The swift expansion of wind power will also suffer from diminishing marginal returns as new wind capacity will be located in areas with lower and less consistent wind speeds. As a result, fewer megawatt hours of power will be produced from newly-built windmills. Moreover the new wind capacity will be developed in increasing remote areas that will require larger investments in transmission and distribution, which will drive costs even higher.

The EIA estimates of the average capacity factor used for onshore wind power plants, at 34.4 percent, appears to be at the higher end of the estimates for current wind projects. This figure is inconsistent with estimates from other studies.[14] According to the EIA's own reporting from 137 current wind power plants in 2003, the average capacity factor was 26.9 percent.[15] In addition, a recent analysis of wind capacity factors around the world finds an actual average capacity factor of 21 percent.[16] Moreover, other estimates find capacity factors in the mid teens and as low as 13 percent.[17]

Biomass is a more promising renewable power source. Biomass combines low incremental costs relative to other renewable technologies and reliability. Biomass is not intermittent and therefore it is distributable with a capacity factor that is competitive with conventional energy

[12] Tom Hewson and Dave Pressman, "Renewable Overload: Waxman-Markey RES Creates Land-use Dilemmas," *Public Utilities Fortnightly* 61 (August 1, 2009).
[13] "Evidence to the House of Lords Economic Affairs Committee Inquiry into 'The Economics of Renewable Energy'," Memorandum by Dr. Phillip Bratby, May 15, 2008.
[14] Nicolas Boccard, "Capacity Factors for Wind Power: Realized Values vs. Estimates," *Energy Policy* 37, no. 7 (July 2009): 2680.
[15] Cited by Tom Hewson, Energy Venture Analysis, "Testimony for East Haven Windfarm," January 1, 2005, http://www.windaction.org/documents/720 (accessed December 2010).
[16] Boccard.
[17] See "The Capacity Factor of Wind, Lightbucket," http://lightbucket.wordpress.com/2008/03/13/the-capacity-factor-of-wind-power/, (accessed December 22, 2010) and National Wind Watch, FAQ, http://www.wind-watch.org/faq-output.php (accessed December 2010).

sources. Moreover biomass plants can be located close to urban areas with high electricity demand. But biomass electricity suffers from land use issues even more so than wind.

The expansion of biomass power plants will require huge additional sources of fuel. Wood and wood waste comprise the largest source of biomass energy today. Other sources of biomass include food crops, grassy and woody plants, residues from agriculture or forestry, oil-rich algae, and the organic component of municipal and industrial wastes.[18] Biomass power plants will compete directly with other sectors (construction, paper, furniture) of the economy for wood and food products and arable land.

One study estimates that 66 million acres of land would be required to provide enough fuel to satisfy the current state RPS mandates and a 20 percent federal RPS in 2025.[19] When the clearing of new farm and forestlands are figured into the GHG production of biomass, it is likely that biomass increases GHG emissions.

The competition for farm and forestry resources would not only cause biomass fuel prices to skyrocket, but also cause the prices of domestically-produced food, lumber, furniture and other products to rise. The recent experience of ethanol and its role in surging corn prices can be casually linked to the recent food riots in Mexico and the surge in hunger in the Darfur region of Sudan. These two examples serve as reminders of the unintended consequences of government mandates for biofuels. The lesson is clear: biofuels compete with food production and distort the market.

Calculation of the Net Cost of New Renewable Electricity

To calculate the cost of renewable energy under the AEPS, BHI used data from the Energy Information Administration (EIA), a division of the U.S. Department of Energy, to determine the percent increase in utility costs that Ohio residents and businesses would experience. This calculated percent change was then applied to calculated elasticities, as described in the STAMP modeling section.

We collected historical data on the retail electricity sales by sector from 1990 to 2008 and projected its growth through 2025 using its historical compound annual growth rate (3.6 percent).[20] To these totals, we applied the percentage of renewable sales prescribed by the Ohio AEPS. By 2025, renewable energy sources must account for 25 percent of total electricity sales in Ohio.

[18] Biomass Energy Basics, National Renewable Energy Laboratory, Biomass Basics, http://www.nrel.gov/learning/re_biomass.html (accessed December, 2010).
[19] Hewson, 61.
[20] U.S. Department of Energy, Energy Information Administration, Ohio Electricity Profile 2010, "Table 5: Electric Power Industry Generation by Primary Energy Source, 1990 through 2008," http://www.eia.doe.gov/cneaf/electricity/st_profiles/Ohio.html. (accessed January 2011).

Next we projected the growth in renewable sources that would have taken place absent the AEPS. We used the EIA's projection of renewable energy sources by fuel for the East Central Area Reliability Coordination Agreement Power Area through 2025 as a proxy to grow renewable sources for Ohio. We used the growth rate of these projections to estimate Ohio's renewable generation through 2025 absent the AEPS.[21]

We subtracted our baseline projection of renewable sales from the AEPS-mandated quantity of sales for each year from 2016 to 2025 to obtain our estimate of the annual increase in renewable sales induced by the AEPS in megawatt hours (MWhs). The AEPS mandate exceeds our projected renewable in all projected years (2016 to 2025). This figure also represents the maximum number of MWhs of electricity from conventional sources that are avoided, or not generated, through the AEPS mandate. We will revisit this shortly. Table 4 contains the results.

Table 4: Projected Electricity Sales, Eligible Renewables and Required under RPS

Year	Projected Electricity Sales MWhs (000s)	Eligible Renewable MWhs (000s)	RPS Requirement MWhs (000s)	Difference MWhs (000s)
2016	140,878	756	6,340	5,584
2017	142,792	756	7,854	7,098
2018	144,691	756	9,405	8,649
2019	143,779	756	10,783	10,028
2020	142,862	756	12,143	11,388
2021	141,942	756	13,484	12,729
2022	143,232	756	15,039	14,284
2023	144,515	756	16,619	15,863
2024	145,790	756	18,224	17,468
2025	147,058	756	18,382	17,626
Total	1,437,539	7,558	128,274	120,716

To estimate the cost of producing the additional extra renewable energy under an AEPS against the baseline, we used estimates of the LEC, or financial breakeven cost per MWh to produce the electricity.[22] However, as outlined in the "electricity generation cost" section above, the EIA numbers provide a rather optimistic picture of the cost and generating capacity

[21] U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 2010*, "Table 92: Renewable Electricity Generation by Fuel," http://www.eia.doe.gov/oiaf/archive/aeo10/aeoref_tab.html (accessed January 2010).
[22] U.S. Department of Energy, Energy Information Administration, *2016 Levelized Cost of New Generation Resources from the Annual Energy Outlook 2010* (2008/$MWh), http://www.eia.doe.gov/oiaf/aeo/electricity_generation.html (accessed September 2010).

of renewable electricity, particularly for wind power. A literature review provided alternative LEC estimates that were generally higher and capacity factors that were lower for renewable generation technologies than the EIA estimates.[23] We used these alternative figures to calculate our "high" LEC estimates and the EIA figures to calculate our "low" cost estimates and the average of the two to calculate our "average" cost estimates. Table 5 displays the LEC and capacity factors for each generation technology.

Table 5: LEC and Capacity Factors for Electricity Generation Technologies

	Capacity Factor (percent)	Total Production Cost (cents/MWh)		
		2010	2020	2025
Coal				
Low	74.0	67.41	64.82	63.53
Average	79.5	83.96	85.21	79.39
High	85.0	100.50	105.60	95.25
Gas				
Low	85.0	75.86	73.25	73.25
Average	86.0	79.48	76.77	75.42
High	87.0	83.10	80.30	77.60
Nuclear				
Low	90.0	76.94	59.20	49.33
Average	90.0	97.97	85.35	74.34
High	90.0	119.00	111.50	99.35
Biomass				
Low	83.0	113.90	103.54	98.36
Average	75.5	112.50	95.27	80.62
High	68.0	111.10	86.99	62.88
Wind				
Low	34.4	287.67	269.54	251.40
Average	26.9	201.22	188.54	175.85
High	15.5	148.78	96.10	87.50

[23] For coal, gas and nuclear generation we used the production cost estimates from the International Energy Agencies, Energy Technology Analysis Programs, "Technology Brief E01: Cola Fired Power, E02: Gas Fired Power, E03: Nuclear Power and E05: Biomass for Heat and Power," (April 2010), http://www.etsap.org/E-techDS/ (accessed December 2010). To the production costs we added transmission costs from the EIA using the ratio of transmissions costs to total LEC costs. For wind power we used the IEA estimate for levelized capital costs and variable and fixed O & M costs. For transmission cost we used the estimated costs from several research studies that ranged from a low of $7.88 per kWh to a high of $146.77 per kWh, with an average of $60.32 per MWh. The sources are as follows:
Andrew Mills, Ryan Wiser, and Kevin Porter, "The Cost of Transmission for Wind Energy: A Review of Transmission Planning Studies," Ernest Orlando Lawrence Berkeley National Laboratory, http://eetd.lbl.gov/EA/EMP (accessed December 2010); Competitive Renewable Energy Zones (CREZ) Transmission Optimization Study, The Electric Reliability Council of Texas, April 2, 2008 http://www.ercot.com/news/presentations/2006/ATTCH_A_CREZ_Analysis_Report.pdf (accessed December 2010); Sally Maki and Ryan Pletka, Black & Veatch, California's Transmission Future, August 25, 2010, http://www.renewableenergyworld.com/rea/news/article/2010/08/californias-transmission-future (accessed December 22, 2010).

We used the 2016 LEC for the years 2010 through 2018 to calculate the cost of the new renewable electricity and avoided conventional electricity, assuming that before 2016 LEC underestimates the actual costs for those years and for 2017 and 2018, the 2016 LEC slightly overestimates the actual costs. We assumed that the differences would, on balance, offset each other. For 2019 and 2020 we used the 2020 LEC. The assumption is that LEC will decline over time due to technological improvements over time.

We use the EIA's reference case scenario for all technologies. Since capital costs represent the large component of the cost structure for most technologies, we used the percentage change in the capital costs from 2016 to 2025 to adjust the 2016 LECs to 2025. For the technologies that the EIA does not forecast LECs in 2020, we used the average of the 2016 and 2025 LEC calculations, assuming a linear change over the period.

Once we computed new LECs for the years 2020 and 2025 we applied these figures to the renewable energy estimates for the remainder of the period.

For conventional electricity we assumed that the technologies are avoided based on their costs, with the highest cost combustion turbine avoided first. For coal and gas, we assumed they are avoided based on their estimated proportion of total electric sales for each year. Although hydroelectric and nuclear are not the cheapest technology, we assume no hydroelectric or nuclear sources are displaced since most were built decades ago and offer relatively cheap and clean electricity today.

We also adjusted the avoided cost of conventional energy to account for the lower capacity factor of wind relative to conventional energy sources. We multiplied the cost of each conventional energy source by the difference between its capacity factor and the capacity factor for the renewable source, and then by the ratio of the new generation of the renewable source to the total new generation of renewable under the AEPS. For example, for coal, we multiplied the avoided amount generation of electricity from coal (15.102 million MWhs in 2025) by the LEC of coal ($79.39 per MWh) and then by one minus the difference between the capacity factor of coal and the weighted average (using MWs as weights) capacity factor of wind (27 percent). This process is repeated for each conventional electricity resource.

These LECs are applied to the amount of electricity supplied from renewable sources under the AEPS, because this figure represents the amount of conventional electricity generation capacity that presumably will not be needed under the AEPS. The difference between the cost of the new renewable sources and the costs of the conventional electricity generation Ohio represents the net cost of the AEPS. Tables 6, 7 and 8 on the following pages display the results of our Average, Low and High Cost calculations respectively.

We converted the aggregate cost of the AEPS into a cost per-kWh by dividing the cost by the estimated total number of kWh sold for that year. For example, in 2025 under the average cost scenario in Table 6, we divided $1.427 million into 147.058 million kWhs for a cost of 0.97 cents per kWh.

Table 6: Average Cost Case of RPS Mandate from 2016 to 2025

Year	Gross Cost (2010 $000s)	Less Conventional (2010 $000s)	Total (2010 $000s)
2016	640,053	159,736	480,317
2017	813,605	203,052	610,553
2018	991,433	247,433	744,001
2019	1,149,449	286,869	862,580
2020	1,036,689	321,571	715,118
2021	1,158,790	359,446	799,345
2022	1,300,342	403,353	896,988
2023	1,444,168	447,967	996,201
2024	1,590,240	493,277	1,096,963
2025	1,604,669	497,753	1,106,916
Total	**11,729,439**	**3,420,456**	**8,308,983**

Table 7: Low Cost Case of RPS Mandate from 2016 to 2025

Year	Gross Cost (2010 $000s)	Less Conventional (2010 $000s)	Total (2010 $000s)
2016	628,556	256,756	371,800
2017	798,991	326,379	472,612
2018	973,625	397,715	575,910
2019	1,128,802	461,104	667,699

2020	994,660	538,994	455,666
2021	1,111,811	602,476	509,335
2022	1,247,624	676,072	571,552
2023	1,385,620	750,850	634,770
2024	1,525,769	826,795	698,974
2025	1,539,614	834,297	705,316
Total	**11,335,073**	**5,671,438**	**5,663,634**

Table 8: High Cost Case of RPS Mandate from 2016 to 2025

Year	Gross Cost (2010 $000s)	Less Conventional (2010 $000s)	Total (2010 $000s)
2016	658,952	101,244	557,708
2017	837,629	128,698	708,931
2018	1,020,708	156,828	863,881
2019	1,183,390	181,823	1,001,567
2020	1,073,642	212,553	861,089
2021	1,200,096	237,588	962,508
2022	1,346,693	266,610	1,080,082
2023	1,495,646	296,099	1,199,547
2024	1,646,925	326,048	1,320,876
2025	1,661,869	329,007	1,332,862
Total	**12,125,550**	**2,236,499**	**9,889,051**

The Advanced Energy Source (AES) section of the law was calculated using a slightly different methodology. The law does not include a step-up requirement, unlike the RPS section, but does include a language requiring 12.5 percent of energy be produced by advanced energy sources by 2025. For this reason, we only considered costs that would be incurred in 2025, leading to our results being a minimum should AES be required prior to 2025.

Using Ohio Public Utility Commission estimates, energy sales in 2025 would be 145,790,000 MWh, meaning that 18,223,750 MWh of energy would need to come from advanced energy sources, as defined by the AEPS laws.[24] Due to the raw size of this requirement, we believe that the source will likely come from two types of power plants that the law specifically mentions: new nuclear power and clean coal.

Our assumption is that each advanced power source would account for 50 percent of the mandate, or 9,111,875 MWH. Applying the same cost per MWh methodology as used for the RPS, we determined the cost, in 2025 of the AES section of the AEPS law. This cost was combined with the calculated cost of the RPS, to determine the percentage increase in the cost of electricity, which was then used to determine the ratepayer and economic effects.

Ratepayer Effects

To calculate the effect of the AEPS on electricity ratepayers, we used EIA data on the average monthly electricity consumption by type of customer: residential, commercial and industrial.[25] The monthly figures were multiplied by 12 to compute an annual figure. We inflated the 2008 figures for each year using the average annual increase in electricity sales over the entire period.[26]

We calculated an annual per-kWh increase in electricity cost by dividing the total cost increase – calculated in the section above — by the total electricity sales for each year. We multiplied the per-kWh increase in electricity costs by the annual kWh consumption for each type of ratepayer for each year. For example, we expect the average residential ratepayer to consume 12,629 kWhs of electricity in 2025 and we expect the average cost scenario to raise electricity costs by 0.97 cents per kWh in the same year in our average cost case. Therefore, we expect residential ratepayers to pay an additional $123 in 2025.

Modeling the AEPS using STAMP

We simulated these changes in the STAMP model as a percentage price increase on electricity to measure the dynamic effects on the state economy. The model provides estimates of the

[24] Ohio Public Utility Commission. Estimated Quantification of Statewide Compliance Obligations Associated with Renewable Energy Component of the Alternative Energy Portfolio Standard. http://www.puco.ohio.gov/emplibrary/files/util/EnergyEnvironment/SB221/aeps%20estimate.pdf

[25] U.S. Department of Energy, Energy Information Administration, "Average electricity consumption per residence in MT in 2008," (January 2010) http://www.eia.doe.gov/cneaf/electricity/esr/table5.html. The 2008 consumption figures were inflated to 2010 using the increase in electricity demand from the EIA of 0.89 percent compound annual growth rate.

[26] U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 2010*, "Table 8: Electricity Supply, Disposition, Prices, and Emissions," http://www.eia.doe.gov/oiaf/aeo/aeoref_tab.html. (accessed December 22, 2010).

proposals' impact on employment, wages and income. Each estimate represents the change that would take place in the indicated variable against a "baseline" assumption of the value that variable for a specified year in the absence of the AEPS policy.

Because the AEPS requires Ohio households and firms to use more expensive "advance" power than they otherwise would have under a baseline scenario, the cost of goods and services will increase under the AEPS. These costs would typically manifest through higher utility bills for all sectors of the economy. For this reason we selected the sales tax as the most fitting way to assess the impact of the AEPS. Standard economic theory shows that a price increase of a good or service leads to a decrease in overall consumption, and consequently a decrease in the production of that good or service. As producer output falls, the decrease in production results in a lower demand for capital and labor.

BHI utilized its STAMP (State Tax Analysis Modeling Program) model to identify the economic effects and understand how they operate through a state's economy. STAMP is a five-year dynamic CGE (computable general equilibrium) model that has been programmed to simulate changes in taxes, costs (general and sector-specific) and other economic inputs. As such, it provides a mathematical description of the economic relationships among producers, households, governments and the rest of the world. It is general in the sense that it takes all the important markets, such as the capital and labor markets, and flows into account. It is an equilibrium model because it assumes that demand equals supply in every market (goods and services, labor and capital). This equilibrium is achieved by allowing prices to adjust within the model. It is computable because it can be used to generate numeric solutions to concrete policy and tax changes.[27]

In order to estimate the economic effects of the AEPS we used a compilation of six STAMP models to garner the average effects across various state economies: New York, North Carolina, Washington, Kansas, Indiana and Pennsylvania. These models represent a wide variety in terms of geographic dispersion (Northeast, Southeast, Midwest, The Plains and West) economic structure (industrial, high-tech, service and agricultural) and electricity sector makeup.

First, we computed the percentage change to electricity prices as a result of three different possible AEPS policies. We used data from the EIA from the state electricity profiles, which contains historical data from 1990-2008 for retail sales by sector (residential, commercial, industrial, and transportation) in dollars and MWhs and average prices paid by each sector.[28] We inflated the sales data (dollars and MWhs) though 2020 using the historical growth rates

[27] For a clear introduction to CGE tax models, see John B. Shoven and John Whalley, "Applied General-Equilibrium Models of Taxation and International Trade: An Introduction and Survey," *Journal of Economic Literature* 22 (September, 1984): 1008. Shoven and Whalley have also written a useful book on the practice of CGE modeling entitled Applying General Equilibrium (Cambridge: Cambridge University Press, 1992).

[28] U.S. Department of Energy, Energy Information Administration, Ohio Electricity Profile 2010, Table 8: Retail Sales, Revenue, and Average Retail Price by Sector, 1990 through 2008, http://www.eia.doe.gov/cneaf/electricity/st_profiles/Ohio.html (accessed January 2011).

for each sector for each year. We then calculated a price for each sector by dividing the dollar value of the retails sales by kWhs. Then we calculated a weighted average kWh price for all sectors using MWhs of electricity sales for each sector as weights. To calculate the percentage electricity price increase we divided our estimated price increase by the weighted average price for each year. For example, in 2025 for our average cost case we divided our average price of 10.47 cents per kWh by our estimated price increase of 0.97 cents per kWh for a price increase of 9.26 percent.

Using these three different utility price increases – 1 percent, 4.5 percent and 5.25 percent – we simulated each of the six STAMP models to determine what outcome these utility price increases would have on each of the six state's economy. We then averaged the percent changes together to determine what the average effect of the three utility increases. Table 9 displays these elasticities, which were then applied to the calculated percent change in electricity costs for the state of Ohio discussed above.

Table 9: Elasticities for the Economic Variables

Economic Variable	Elasticity
Employment	-0.022
Gross wage rates	-0.063
Investment	-0.018
Disposable Income	-0.022

We applied the elasticities to percentage increase in electricity price and then applied the result to Ohio economic variables to determine the effect of the AEPS. These variables were gathered from the Bureau of Economic Analysis Regional and National Economic Accounts as well as the Bureau of Labor Statistics Current Employment Statistics.[29]

[29] See the following: Bureau of Economic Analysis, "National Economic Accounts," http://www.bea.gov/national/; Regional Economic Accounts, http://www.bea.gov/regional/index.htm. See also Bureau of Labor Statistics, "Current Employment Statistics ," http://www.bls.gov/ces/.

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Introduction to the Input-Output Model Framework and how it is Used to Estimate the Economic Impacts of Increased Electric Costs in Ohio

1. Mathematics of the Input-Output Framework[1]

An input-output framework begins with observed transaction data for a particular region. For example, the IMPLAN model is constructed from data at the national, state, and county levels. The transactions are typically converted into dollar amounts, as that makes tracing economic flows much easier, since dollars are a uniform measure.

We assume that the economy is made of up of numerous sectors, e.g., manufacturing, mining, agriculture, services, government, and foreign trade. To construct an input-output table, we record how the output produced (supplied) by a given sector, such as steel, is purchased by (demanded) the other industry sectors (who then use those purchased inputs to manufacture other goods), plus external sales to government and consumers. Thus, if there the economy consists of N industries, the total output produced by an individual industry, X_k, will be purchased by the other N–1 industries, used by itself, and sold to final consumers. Thus,

$$X_k = z_{k,1} + z_{k,2} + z_{k,3} + ... + z_{k,N} + Y_k \tag{1}$$

where the $z_{i,n}$ are sales to each industry n, and Y_k equals sales for final demand (i.e., to consumers, the government, and for export). Since we have N industries, we can write the entire set of flows as

$$\begin{bmatrix} X_1 = z_{1,1} + z_{1,2} + ... + z_{1,k} + ... + z_{1,N} + Y_1 \\ X_2 = z_{2,1} + z_{2,2} + ... + z_{2,k} + ... + z_{2,N} + Y_2 \\ \vdots \\ X_k = z_{k,1} + z_{k,2} + ... + z_{k,k} + ... + z_{k,N} + Y_k \\ \vdots \\ X_N = z_{N,1} + z_{N,2} + ... + z_{N,k} + ... + z_{N,N} + Y_N \\ \end{bmatrix} \tag{2}$$

Each column of coefficients on the right-hand side of equation (2), i.e.,

[1] For a far more detailed discussion, see Leontief, *op. cit.* See also, R. Miller and P. Blair, *Input-Output Analysis: Foundations and Extensions*, (Englewood Cliffs, NJ: Prentice-Hall 1985), Chp. 2.

$$\begin{bmatrix} z_{1,k} \\ z_{2,k} \\ \vdots \\ z_{k,k} \\ \vdots \\ z_{N,k} \end{bmatrix}$$

represents the purchases from industry sector k to the N–1 other industry sectors, and to itself ($z_{k,k}$). In other words, industry k purchases inputs from all of the other industries to produce output X_k. When all of the N different columns are combined, they create an *input-output table*, with each selling sector a different row, and each purchasing sector a different column, as shown in Table 1.

Table 1: An Input-Output Table

		Purchasing industry sector					
		1	**2**	**...**	**K**	**...**	**N**
	1	$Z_{1,1}$	$Z_{1,2}$	...	$Z_{1,k}$		$Z_{1,N}$
Selling	**2**	$Z_{2,1}$	$Z_{2,2}$	...	$Z_{2,k}$		$Z_{2,N}$
Industry	$\vdots$	$\vdots$	$\vdots$		$\vdots$		$\vdots$
Sector	**k**	$Z_{k,1}$	$Z_{2,k}$	...	$Z_{k,k}$		$Z_{N,k}$
	$\vdots$	$\vdots$	$\vdots$		$\vdots$		$\vdots$
	N	$Z_{N,1}$	$Z_{N,2}$	...	$Z_{N,k}$		$Z_{N,N}$

Although the input-output table above incorporates all of the inter-industry sales and purchases, it does not account for the remainder of the economy. For example, final demand includes sales to consumers, state, local, and the federal government, investment, and exports. Moreover, in addition to buying outputs from other industries, each industry pays wages to its employees (W), pays for government services (in the form of taxes), pays for capital (in the form of interest payments, I), and profits. Together, these components are called *value-added.* On top of that, each sector imports goods and services from outside the economy. For example, if building a new high-voltage transmission line requires buying substation equipment from Germany, then the input-output model for the U.S. would consider that an import.

The input-output framework assumes that production coefficients are fixed. This means that there are specific quantities of inputs required to produce a given output. Thus, building a car—any car—is assumed to take (say) 2000 pounds of steel, 100 pounds of rubber, 200 pounds of glass, and so forth. Obviously, this assumption of fixed production coefficients does not hold true entirely—the amount of materials needed to build a large pick-up truck is greater than that needed to built a subcompact car—but for estimating short-run impacts, the overall assumption is reasonable: building more cars and trucks will clearly require more steel, producing more steel will require more iron ore, and so forth.

Because the input-output framework assumes fixed production coefficients (called a "Leontief production function"), the necessary inputs needed to produce a unit of output are all constant. If we divide the purchases made by industry k from every industry, i.e., the $z_{i,k}$, to produce output X_k, we derive the *technical coefficients, $a_{i,k}$*, for industry k. In other words,

$$a_{i,k} = \frac{Z_{i,k}}{X_k} \tag{3}$$

If we substitute equation (3) into equation (2), we obain:

$$\begin{bmatrix} X_1 = a_{1,1}X_1 + a_{1,2}X_2 + \ldots + a_{1,k}X_k + \ldots + a_{1,N}X_N + Y_1 \\ X_2 = a_{2,1}X_1 + a_{2,2}X_2 + \ldots + a_{2,k}X_k + \ldots + a_{2,N}X_N + Y_2 \\ \vdots \\ X_k = a_{k,1}X_1 + a_{k,2}X_2 + \ldots + a_{k,k}X_k + \ldots + a_{k,N}X_N + Y_n \\ \vdots \\ X_N = a_{N,1}X_1 + a_{N,2} + \ldots + a_{N,k}X_k + \ldots + a_{N,N}X_N + Y_N \end{bmatrix} \tag{4}$$

What equation (4) tells us is that some of the output produced by an industry is sold to all other industries and used in fixed quantities to produce those industries' outputs, and the remainder is sold as final demand to consumers, government, and as exports. As a final step, we isolate the final demands for the output from each industry, Y_k. Thus,

$$\begin{bmatrix} X_1 - a_{1,1}X_1 + a_{1,2}X_2 + \ldots + a_{1,k}X_k + \ldots + a_{1,N}X_N = Y_1 \\ X_2 - a_{2,1}X_1 + a_{2,2}X_2 + \ldots + a_{2,k}X_k + \ldots + a_{2,N}X_N = Y_2 \\ \vdots \\ X_k - a_{k,1}X_1 + a_{k,2}X_2 + \ldots + a_{k,k}X_k + \ldots + a_{k,N}X_N = Y_n \\ \vdots \\ X_N - a_{N,1}X_1 + a_{N,2} + \ldots + a_{N,k}X_k + \ldots + a_{N,N}X_N = Y_N \end{bmatrix} \tag{5}$$

Equation (5) lies at the heart of the economic impact analysis, because it allows us to answer the question, "If the demand for the output of industry k changes, by how much would the output of all of the other industries change?" For example, building a new high-voltage transmission line would increase the demand for concrete, steel, and so forth. How will these changes in demand ripple through the Ohio economy and what will be the final changes in output levels in all other industries, as well as the change in total labor (i.e., jobs) and income?

To answer this sort of question, we solve equation (5) for each of the X_i. This requires a bit of matrix algebra. It turns out that the solution can be written as

$$\mathbf{X} = (\mathbf{I} - \mathbf{A})^{-1}\mathbf{Y} \tag{6}$$

where

$$\mathbf{A} = \begin{bmatrix} a_{1,1} \cdots a_{1,N} \\ a_{2,1} \cdots a_{2,N} \\ \vdots \\ a_{k,1} \cdots a_{k,N} \\ \vdots \\ a_{N,1} \cdots a_{N,N} \end{bmatrix}, \qquad \mathbf{X} = \begin{bmatrix} X_1 \\ X_2 \\ \vdots \\ X_k \\ \vdots \\ X_N \end{bmatrix}, \qquad \mathbf{Y} = \begin{bmatrix} Y_1 \\ Y_2 \\ \vdots \\ Y_k \\ \vdots \\ Y_N \end{bmatrix}$$

The matrix $(\mathbf{I} - \mathbf{A})^{-1}$ is called the *Leontief inverse.* By changing the level of final demand in the output vector **Y** and knowing the technical coefficients $a_{i,k}$, we can determine the flows through the economy.

There are three types of economic impacts typically evaluated in an input-output study: *direct, indirect,* and *induced.* Direct effects are those that are a direct result of an increase in demand for good k. For example, building a new high-voltage transmission line will require concrete for the tower foundations. Thus, the demand for concrete will increase. That is a *direct* impact. Increasing the demand for concrete, however, will require concrete manufacturers to increased their purchases of all of the inputs used to manufacture concrete, including sand, gravel, electricity, and so forth, thus increasing the demand for all of those inputs. Thus, the *direct* increase in the demand for concrete *indirectly* increases the demand for all of these other products. Finally, all of these manufacturers pay wages to employees. Those employees, in turn spend a portion of their wages on food, electricity, new cars, and so forth. As a result, we say the resulting consumer spending from households *induces* further increases in demand, and thus additional economic impacts.

Because of the interconnections among industries and between industries and households, an increased demand for just one good or service is said to cause *ripple effects* throughout the economy. These ripple effects lead to additional jobs and increases disposable income as workers are hired, equipment and supplies are purchased from other local businesses, wages are paid to employees, and taxes are paid to government entities. These impacts are called *multiplier effects* or *multipliers.* For example, if the demand for concrete increases by \$1 million and the overall impact on the Ohio economy is \$2 million, then the output multiplier equals \$2million/\$1 million = 2.0. We can also calculate jobs and income multipliers. For example, if 100 workers are hired to construct a transmission line, and the overall ripple effects lead to 50 new jobs created as a result, the employment multiplier will equal 150/100 = 1.5.

2. Estimating economic impacts

Ripple effects act like waves bouncing off walls. Eventually, each subsequent round of impacts decreases in magnitude, just like a wave bouncing off walls eventually subsides. The speed at which these ripple effects diminish, and the overall magnitude of multipliers, depends on what are called *leakages* out of an economy. For example, not all of the materials needed to build the transmission line will be purchased from Ohio companies. Moreover, some of the workers hired to construct the project may be from outside the state. Furthermore, Ohio workers who are hired will not spend all of their wages within the state, but will instead buy goods and services from neighboring states, too. As we discuss in the sections that follow, assumptions about *leakage rates*, i.e., what fraction of spending occurs outside Ohio, are crucial in estimating the overall economic impacts to the state.

a. Calculating multipliers[2]

Multipliers are calculated from the Leontief inverse matrix defined previously. For example, suppose we have an economy with just two industries, industry **X** and industry **Y**, with the following technical coefficients matrix.

$$\mathbf{A} = \begin{bmatrix} 0.15 & 0.25 \\ 0.20 & 0.05 \end{bmatrix} \tag{7}$$

What this means is that to produce \$1 of additional output, industry **X** purchases \$0.15 from itself and \$0.20 from industry **Y**. The remaining \$0.65 is accounted for through valued added – wages and salaries paid to employees, taxes paid to federal, state, and local governments, and profits. Similarly, to produce \$1 of additional output, industry **Y** purchases \$0.25 from industry **X**, \$0.05 from itself, and the remaining \$0.70 is value added. It turns out the Leontief inverse matrix (ignoring the value added impacts) is

$$(\mathbf{I} - \mathbf{A})^{-1} = \begin{bmatrix} 1.254 & 0.33 \\ 0.264 & 1.122 \end{bmatrix} \tag{8}$$

The values in the Leontief inverse provide the output multipliers, by adding up each column. Specifically, if there is a \$1 increase in final demand for the output of industry **X**, then the total increase in demand for output of industry **X** is \$1.254 - \$1 for the increase in final demand, and \$0.254 for inter-industry and intra-industry use. There is also an *indirect* increase in demand of

[2] For a much more detailed discussion, see Miller and Blair, fn. 1, from which these examples are drawn.

\$0.264 of industry **Y** for inter-industry and intra-industry use. Thus, if we sum down the first column, a \$1 increase in demand for industry **X** leads to a total increase in output of \$1.254 + \$0.264 = \$1.518. The output multiplier for industry **X** is thus \$1.518/\$1 = 1.518. Because we are not considering households in this example, this output multiplier is called a *Type I* multiplier.

Next, we consider household impacts, such as from wages paid to households. Suppose that industry 1 **X** pays \$0.30 in wages per dollar of output and that industry 2 pays \$0.25 in wages per dollar of output. By incorporating these payments into the technical coefficients matrix, we can determine the direct, indirect, and *induced* impacts from increased output. So, we rewrite the technical coefficients matrix as follows:

$$\mathbf{A} = \begin{bmatrix} 0.15 & 0.25 & 0.05 \\ 0.20 & 0.05 & 0.40 \\ 0.30 & 0.25 & 0.05 \end{bmatrix} \qquad (\mathbf{I}-\mathbf{A})^{-1} = \begin{bmatrix} 1.365 & 0.425 & 0.251 \\ 0.527 & 1.348 & 0.595 \\ 0.570 & 0.489 & 1.289 \end{bmatrix} \tag{9}$$

The new technical coefficients matrix **A** now contains 3 rows and 3 columns. The 2x2 matrix of values in the top left hand corner is the original matrix shown in equation (7). The third column represents households. So, in the example, households spend \$0.05 per dollar buying items from industry **X**, \$0.40 per dollar buying items from industry **Y**, and \$0.05 buying items from within the household sector. (The remainder is spent paying taxes and for investment.). The third row shows that industry **X** spends \$0.30 per dollar on wages, while industry **Y** spends \$0.25 per dollar on wages.

When we calculate the new Leontief inverse $(\mathbf{I}-\mathbf{A})^{-1}$, the first thing to notice is that the previous coefficients (the top-left 2x2 matrix) are all larger than they were in equation (8). This is because we are now including household demand impacts. Now, the output multiplier for industry **X** is the sum of the first column [1.365, 0.527, 0.570], or 2.462. Thus, for every \$1 increase in demand in industry **X**, total output in the local economy increases by \$2.462. The output multiplier for industry **X** is therefore 2.4262. In matrix notation, the output multiplier for industry *i* in our N-industry economy is:

$$M_{output,i} = \mathbf{i}_i \bullet (\mathbf{I}-\mathbf{A})^{-1} \bullet \mathbf{i}_i', \tag{10}$$

where $\mathbf{i}_i = \begin{bmatrix} 0 & \cdots & \mathbf{1}_j & \cdots & 0 \end{bmatrix}$.[3]

In our 2-industry example, we can calculate the household income multiplier for industry **X** in several ways. The first is to treat household spending as outside our model and estimate impacts using the Type 1 multipliers. To do that, we go back to the initial Leontief inverse in equation (8)

[3] In other words, $\mathbf{i_j}$ is a 1xN unit vector having value 1 for industry j. The term $\mathbf{i_j}$'is called the *transpose* of $\mathbf{i_i}$, and is a Nx1 column vector.

and multiply the household income coefficients in **A** for our two industries (the third row) by the first column in the Leontief inverse, and add the results, i.e.,

$$H_X = (0.30)(1.254) + (0.25)(0.264) = 0.442$$

What this means is that, for every $1 increase in demand for the output of industry **X**, total household income increase by $0.442 because of the direct and indirect economic impacts on output. Thus, the *Type 1 multiplier* is $0.442/$0.30 = 1.47.

If we include the economic impact caused by households also spending money in the economy, the result is called a *Type II multiplier*. To do this, we use the new **A** and $(\mathbf{I–A})^{-1}$ matrices shown above. For industry **X**, we calculate the total household income change, including the within-household sector impacts and divide by $0.30 that industry 1 pays directly to households in the form of wages. Thus, we have

$$H'_X = (0.30)(1.365) + (0.25)(0.527) + (0.05)(0.57) = 0.570$$

and the multiplier is $H'_X/0.30$ = $0.57/$0.30 = 1.9. Note also that the overall household impact, $0.57 is just the value in the last row of the Leontief inverse matrix for industry **X**.

Finally, we estimate *employment multipliers*, following the same approaches previously outlined. Only this time, the multipliers do not reflect dollar changes, but changes in employment. To do this, one determines the number of employees (in full-time equivalents) per dollar of output in each industry. For example, suppose for each million dollars of output produced in industry **X**, 300 employees are required, and that in industry 2, 400 employees are used per million dollars of output. This translates to values of 0.003 and 0.004 employees per dollar in industries **X** and **Y**, respectively. Similarly, assume the household sector requires 100 employees per million dollars of output, or 0.001 employees per dollar. Then, using the Leontief inverse matrix in equation (9), we calculate the total employment impact for industry **X** as

$$E'_X = (0.003)(1.365) + (0.004)(0.527) + (0.001)(0.570) = 0.000572$$

Then, using the same approach as for calculating the Type II income multipliers, we can calculate the Type II employment multiplier for industry 1 as $E'_X/0.0003$ = 1.907. Thus, for every job added in industry **X**, a total of 1.907 jobs are added in the entire economy.

3. The IMPLAN Model

IMPLAN was first developed in the 1970s by the U.S. Forest service to analyze the economic impacts of different forestry policies. The current version of IMPLAN is maintained by the University of Minnesota IMPLAN group. IMPLAN provides a detailed breakdown of the U.S. economy, with over 500 separate economic sectors. IMPLAN is widely used by numerous government agencies, including at the federal and state levels.

The IMPLAN model begins with the most current national transactions matrix developed by the current National Bureau of Economic Analysis Benchmark Input-Output Model. Next, the model creates state and county-level values by adjusting the national level data, such as removing industries that are not present in a particular state or economy. The model also estimates imports using what are called *regional purchase coefficients* (RPCs). RPCs measure the proportion of the total supply of a good or service required to meet a particular industry's intermediate demands and final demands that are produced locally. The larger the RPC value, the greater the percentage of total regional demand that is met through local supplies.

In addition to calculating standard Type I and Type II multipliers, IMPLAN can also calculate what are called "SAM multipliers." SAM stands for "Social Accounts Matrix," and is a more detailed breakdown of transactions within an economy. Specifically, whereas the typical input-output framework captures production and consumption, it leaves out some income transactions, such as taxes, savings, and transfer payments. IMPLAN allows users to capture these components as well, and thus derive what are called SAM multipliers.[4] SAM multipliers are a form of Type II multiplier. Thus, SAM multipliers incorporate direct, indirect, and induced impacts, while accounting for the effects of savings, taxes, and transfer payments.

4. Estimating the economic impacts of higher electric prices

To estimate the overall economic impacts of the higher wholesale electric prices and higher capacity market costs, we assumed a short-run elasticity of zero. That is, we assumed consumers would not, initially, reduce their electric consumption in response to the slightly higher electric prices they faced. Since consumer income is assumed to be fixed in the short run, this implies consumers must reduce their expenditures on all other goods and services (including savings and investment) by an equivalent amount.

Similarly, we assumed that in-state businesses would react to the increased price of electricity by reducing their total output such that their aggregate production expenses remained unchanged. This assumption is consistent with the assumption of fixed production coefficients in the Leontief model. It also assumes that businesses would not be able to pass on the increased production costs to consumers.

b. Estimating the total impacts on state output

With these assumptions, we estimate the overall change in output as follows. First, we calculate a weighted-average *regional purchase coefficient* for output in the Ohio economy, excluding

4 For complete discussion of how SAM multipliers are derived, see G. Alward, "Deriving SAM multipliers using IMPLAN," paper presented at the 1996 National IMPLAN Users Conference, Minneapolis, MN, August 15–17, 1996, 1996. Available at: http://implan.com/v3/index.php?option=com_docman&task=doc_download&Itemid=138&gid=127.

electric power. A regional purchase coefficient (RPC) equals the fraction of local demand for a good or service that is satisfied from local production. For example, in Ohio, about 47% of all ready-mix concrete was purchased from in-state manufacturers, based on 2008 data. The weighted RPC, RPC_{OH}, equals the sales-weighted average of the individual sector RPCs, excluding the electric generation sector (assumed to be sector *k*). Thus,

$$RPC_{OH} = \frac{\sum_{i=1, i \neq k}^{N} Q_i \cdot RPC_i}{\sum_{i=1, i \neq k}^{N} Q_i} \tag{11}$$

Similarly, we calculate the weighted-average SAM output multiplier, $\bar{M}_{OH}^{output}$, using the output from each industry as the individual industry weights. Thus, using equation (10) for the output multiplier for industry **i**, we have

$$\bar{M}_{OH}^{output} = \sum_{i=1, j \neq k}^{N} Q_i \cdot \{\mathbf{i}_i \bullet (\mathbf{I} - \mathbf{A})^{-1} \bullet \mathbf{i}_i'\} / \Delta Q_{OH}^{TOT} = \sum_{i=1, j \neq k}^{N} Q_i \cdot M_{output,i} / \Delta Q_{OH}^{TOT}, \tag{12}$$

The total impact on output in the state, ΔQ_{OH}^{TOT}, will equal the weighted RPC times the weighted output multiplier, times the estimated increase in total electric expenditures. Thus, if the total change in electric expenditures is ΔQ_{ELEC}, we have:

$$\Delta Q_{OH}^{TOT} = \Delta Q_{ELEC} \cdot RPC_{OH} \cdot \bar{M}_{OH}^{output} \tag{13}$$

c. Estimating the total impact on state employment

We can follow a similar procedure to estimate the total impacts on state employment arising from the higher electric expenditures, with the additional step of estimating the weighted average employment per million dollars of output, using the employment multipliers calculated by IMPLAN. Thus, the weighted jobs per million dollars of output can be written as:

$$\bar{J}_{OH} = \sum_{i=1, i \neq k}^{N} Q_i \cdot J_i / \Delta Q_{OH}^{TOT}, \tag{14}$$

where J_i is jobs per million dollars of output in industry *i*. Therefore, the overall weighted jobs multiplier is:[5]

[5] The jobs multiplier is just the output multiplier weighted by jobs per million dollars of output.

$$\bar{M}_{OH}^{jobs} = \sum_{i=1, i \neq k}^{N} Q_i \cdot J_i \{\mathbf{i_i} \bullet (\mathbf{I} - \mathbf{A})^{-1} \bullet \mathbf{i_i}'\}, \tag{15}$$

And so, the total impact on jobs in the state from the increased expenditures on electricity will equal:

$$\Delta J_{OH}^{TOT} = (\Delta Q_{ELEC} \cdot RPC_{OH}) \cdot (\bar{J}_{OH} \cdot \bar{M}_{OH}^{jobs}) \tag{16}$$