Jeremy Fisher, PhD.
Senior Strategy and Technical Advisor

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EDUCATION

BROWN UNIVERSITY Providence, Rhode Island
Doctor of Philosophy in Geological Sciences (2006)
Master of Science in Geological Sciences (2003)

UNIVERSITY OF MARYLAND College Park, Maryland
Bachelor of Science in Geology (2001)
Bachelor of Science in Geography (2001)

PROFESSIONAL EXPERIENCE

SIERRA CLUB Oakland, California
Senior Advisor for Strategic Research and Development (2019-present)

Senior Strategy and Technical Advisor (2017-December 2019)

Provides detailed expertise on energy system issues and strategic engagement with utilities, regulatory commission, and partners. Research and development on cutting edge energy system economic issues, supports legal and campaign staff at Sierra Club; provides oversight to consulting practices on energy issues. Develops novels programs to assist utility and fossil sector decarbonizations goals; develops and supports federal policy positions.

SYNAPSE ENERGY ECONOMICS Cambridge, Massachusetts
Principal Associate (2013-2017); Scientist (2007-2013)

Consulted on economic analysis of climate change and energy, carbon, and emissions policies. Developed successful clean energy regulatory strategy. Provides detailed technical and strategic analysis on behalf of public interest groups in US. Provides training to regulators on best practices in energy system planning. Develops quantitative evaluations of regional climate change impact, long- and short-term electric industry planning, carbon reduction strategies, and emissions compliance programs. Lead investigator on avoided emissions tool (AVERT) for US EPA; collaborator on health benefits assessments.

TULANE UNIVERSITY New Orleans, Louisiana
Postdoctoral Researcher (2006-2007)

Modeled carbon balance in forest ecosystems through satellite data and dynamic models. Developed new techniques to assess large-scale forest morbidity and mortality. Tracking impacts of Hurricane Katrina (US Gulf Coast) and large-scale disturbances in Amazon basin. (Brazil).

BROWN UNIVERSITY Providence, Rhode Island
Research Assistant (2001-2006)

Tracked impact of climate change on New England forests from satellites. Worked with West African communities to determine impact of climate change and practice on landscape. Modeled coastal power plant effluent from satellite data.

FELLOWSHIPS & AWARDS

- *Visiting Fellow,* Watson Institute for International Studies, Brown University, 2007
- *Fellow*, National Science Foundation East Asia Summer Institute (EASI), 2003
- *Fellow*, Henry Luce Foundation at the Watson Institute for International Studies, Brown University, 2003

EXPERT TESTIMONY & DECLARATIONS

New Mexico Public Regulation Commission (Case No. 21-00017-UT). Direct and surrebuttal testimony opposing Public Service New Mexico's proposal to abandon Four Corners power plant by selling its share to a coal provider. On behalf of Sierra Club. July 12 and August 30, 2021.

New Mexico Public Regulation Commission (Case No. 20-00222-UT). Direct testimony on stipulation regarding Public Service New Mexico's request to merge Avangrid, with regard to the disposition of Four Corners power plant. On behalf of Sierra Club. June 18, 2021.

Georgia Public Service Commission (Docket Nos. 4822, 16573, & 19279). Rebuttal and surrebuttal testimony in the Georgia Commission's examination of PURPA payments regarding market price suppressive impacts from operations. On behalf of Sierra Club. December 4 and 22, 2020.

Oregon Public Utilities Commission (Docket UE 374). Opening and rebuttal testimony in PacifiCorp's general rate case evaluating the prudence of certain environmental retrofits on coal plants. June 4 & July 24, 2020.

Michigan Public Service Commission (Case No. U-20529). Direct testimony in Indiana Michigan's Power Supply Cost Recovery Plan regarding participation in the Ohio Valley Electric Cooperative. On behalf of Sierra Club. May 11, 2020.

Indiana Utility Regulatory Commission (Cause No. 38703 FAC 127). Direct testimony in Indianapolis Power and Light's fuel cost adjustment regarding commitment and operation of the Petersburg coal power plant. On behalf of Sierra Club, April 21, 2020.

United States Court of Appeals for the Second Circuit (Case 19-3652(L)). Declaration in support of Sierra Club's action to compel the Secretary of Energy to maintain lighting efficiency standards. On behalf of Sierra Club, March 18, 2020.

New Mexico Public Regulation Commission (Case No. 19-00018-UT). Rebuttal testimony in support of Public Service New Mexico's proposal to abandon San Juan power plant, and use of securitization as a recovery mechanism. On behalf of Sierra Club. November 15, 2019.

Kentucky Public Service Commission (Dockets 2018-00294/2018-00295). Direct testimony in Kentucky Utilities / Louisville Gas and Electric's adjustment of rates regarding participation in the Ohio Valley Electric Cooperative. On behalf of Sierra Club. January 16, 2019.

Superior Court of Washington for Thurston County (No. 18-2-03640-34). Declaration in support of Sierra Club opposing PacifiCorp motion for relief to keep certain materials related to the economics of PacifiCorp's coal fleet confidential. On behalf of Sierra Club. September 7, 2018.

United States District Court for the District of Columbia (Civil Action 17-2700-EGS). Declaration in support of Sierra Club's action to compel the Secretary of Energy to complete energy efficiency standards for manufactured housing. On behalf of Sierra Club. June 29, 2018.

Public Utilities Commission of Ohio (Docket 17-32-EL-AIR): Direct testimony in Duke Energy Ohio's request for a rider to include the costs of Ohio Valley Electric Corporation contract costs into rates. On behalf of Sierra Club. June 25, 2018.

California Public Utilities Commission (Investigation 17-04-019): Direct testimony regarding PacifiCorp's compliance with California's Emissions Performance Standard. On behalf of Sierra Club. February 7, 2018.

Mississippi Public Service Commission (Docket No. 2017-AD-112): Direct testimony regarding settlement with Mississippi Power Company on value of Kemper County Combined Cycle plant. On behalf of Sierra Club. October 23, 2017.

Utah Public Service Commission (Docket 14-035-114): Direct and surrebuttal testimonies in the investigation into the costs and benefits of PacifiCorp's proposed Net Metering program, with respect to long-term resource value and environmental benefits. On behalf of Heal Utah. June 8, 2017.

Indiana Utility Regulatory Commission (Cause No. 44872): Direct and rebuttal testimonies regarding Northern Indiana Public Service Company's application for a Certificate of Public Convenience and Necessity for environmental compliance projects at Schahfer units 14 & 15 and Michigan City unit 12. On behalf of Sierra Club. April 3, 2017.

Indiana Utility Regulatory Commission (Cause No. 44871): Direct and rebuttal testimonies regarding Indiana Michigan Company's application for a Certificate of Public Convenience and Necessity to install Selective Catalytic Reduction at Rockport Power Plant Unit 2. On behalf of Citizens Action Coalition of Indiana, Sierra Club, and Valley Watch. February 3, 2017.

Public Utilities Commission of Nevada (Docket Nos. 16-07001, 16-07007, and 16-08027): Direct testimony regarding the economic viability of the North Valmy coal plant. On behalf of Sierra Club. September 30, 2016.

California Public Utilities Commission (Docket 15-09-007): Direct testimony regarding PacifiCorp's application for authority to sell Utah mining assets on a post-hoc basis. On behalf of Sierra Club. July 11, 2016.

Washington Utilities and Transportation Commission (Docket UE-152253): Response, cross-answer, and supplementary cross-answer testimony regarding the general rate case on behalf of Pacific Power & Light Company. On behalf of Sierra Club. June 1, 2016.

Georgia Public Service Commission (Docket 40161): Direct testimony regarding Georgia Power Company's 2016 Integrated Resource Plan. On behalf of Sierra Club. May 18, 2016.

Oregon Public Utility Commission (Docket UM-1712): Direct testimony regarding PacifiCorp's application for approval of Deer Creek Mine transaction. On behalf of Sierra Club. March 5, 2015.

Oklahoma Corporation Commission (Case No. PUD 201400): Direct and rebuttal testimony comparing the modeling performed by Oklahoma Gas & Electric in support of its request for authorization and cost recovery of a Clean Air Act compliance plan and Mustang modernization against best practices in resource planning. On behalf of Sierra Club. December 16, 2014 and January 26, 2015.

New Mexico Public Regulation Commission (Case 12-00390-UT): Direct and surrebuttal testimony evaluating the economic modeling performed by Public Service Company of New Mexico in support of its application for certificate of public convenience and necessity for the acquisition of San Juan Generating Station and Palo Verde units. On behalf of New Energy Economy. August 29, 2014; December 29, 2014.

Wyoming Public Service Commission (Docket No. 20000-446-ER-14): Direct testimony in the matter of the application of Rocky Mountain Power for authority to increase its retail electric utility service rates in Wyoming approximately $36.1 million per year or 5.3 percent. On behalf of Sierra Club. July 25, 2014.

Indiana Utility Regulatory Commissions (Cause No. 44446): Direct testimony evaluating the economic modeling performed on behalf of Vectren South in support of its application for certificate of public convenience and necessity for various retrofits at Brown 1 & 2, Culley 3 and Culley plant, and Warrick 4. On behalf of Sierra Club, Citizens Action Coalition, and Valley Watch. May 28, 2014.

Utah Public Service Commission (Docket No. 13-035-184): Direct testimony In the matter of the application of Rocky Mountain Power for authority to increase its retail electric utility service rates in Utah and for approval of its proposed electric service schedules and electric service regulations. On behalf of Sierra Club. May 1, 2014.

Louisiana Public Service Commission (Docket No. U-32507): Direct and cross answering testimony regarding the application of Cleco Power LLC for: (i) authorization to install emissions control equipment at certain of its generating facilities in order to comply with the federal national emissions standards for hazardous air pollutants from coal and oil-fired electric steam units rule; and (ii) authorization to recover the costs associated with the emissions control equipment in jurisdictional rates. On behalf of Sierra Club. November 8, 2013 and December 9, 2013.

Nevada Public Utilities Commission (Docket No. 13-07021): Direct testimony regarding a joint application of Nevada Power Company d/b/a NV Energy, Sierra Pacific Power Company d/b/a NV Energy (referenced together as "NV Energy, Inc.") and MidAmerican Energy Holdings Company ("MidAmerican") for approval of a merger of NV Energy, Inc. with MidAmerican. On behalf of Sierra Club. October 24, 2013.

Indiana Utility Regulatory Commission (Cause No. 44339): Direct testimony in the matter of Indianapolis Power & Light Company's application for a Certificate of Public Convenience and Necessity for the construction of a combined cycle gas turbine generation facility. On behalf of Citizens Action Coalition of Indiana. August 22, 2013.

Indiana Utility Regulatory Commission (Cause No. 44242): Direct and surrebuttal testimony regarding Indianapolis Power & Light Company's petition for approval of clean energy projects and qualified pollution control property. On behalf of Sierra Club. January 28, 2013; April 3, 2013.

Wyoming Public Service Commission (Docket 2000-418-EA-12): Direct testimony regarding the application of PacifiCorp for approval of a certificate of public convenience and necessity to construct selective catalytic reduction systems on the Jim Bridger Units 3 and 4. On behalf of Sierra Club. February 1, 2013.

Public Service Commission of Wisconsin (Docket No. 6690-CE-197): Direct, rebuttal, and surrebuttal testimony regarding Wisconsin Public Service Corporation's application for authority to construct a multi-pollutant control technology system for Unit 3 of Weston Generating Station. On behalf of Clean Wisconsin. Direct testimony submitted November 15, 2012, rebuttal testimony submitted December 14, 2012, surrebuttal testimony submitted January 7, 2013.

Utah Public Service Commission (Docket 12-035-92): Direct, surrebuttal, and cross-answering testimony regarding Rocky Mountain Power's request for approval to construct Selective Catalytic Reduction systems at Jim Bridger units 3 and 4. On behalf of Sierra Club. November 30, 2012.

Oregon Public Utility Commission (Docket UE 246): Direct testimony in the matter of PacifiCorp's filing of revised tariff schedules for electric service in Oregon. On behalf of Sierra Club. June 20, 2012.

Kentucky Public Service Commission (Docket 2011-00401): Direct testimony regarding the application of Kentucky Power Company for approval of its 2011 environmental compliance plan, for approval of its amended environmental cost recovery surcharge tariff, and for the granting of a certificate of public convenience and necessity for the construction and acquisition of related facilities. On behalf of Sierra Club. March 12, 2012.

Kentucky Public Service Commission (Dockets 2011-00161/2011-00162): Direct testimony regarding the application of Kentucky Utilities/Louisville Gas and Electric Company for certificates of public convenience and necessity and approval of its 2011 compliance plan for recovery by environmental surcharge. On behalf of Sierra Club and Natural Resources Defense Council (NRDC). September 16, 2011.

Kansas Corporation Commission (Docket 11-KCPE-581-PRE): Direct testimony in the matter of the petition of Kansas City Power & Light (KCP&L) for determination of the ratemaking principles and treatment that will apply to the recovery in rates of the cost to be incurred by KCP&L for certain electric generating facilities under K.S.A. 66-1239. On behalf of Sierra Club. June 3, 2011.

Utah Public Service Commission (Docket 10-035-124): Direct testimony in the matter of the application of Rocky Mountain Power for authority to increase its retail electric utility service rates in Utah and approval of its proposal electric service schedules and electric service regulations. On behalf of Sierra Club. May 26, 2011.

Wyoming Public Service Commission (Docket 20000-384-ER-10): Direct **testimony** in the matter of the application of Rocky Mountain Power for authority to increase its retail electric utility rates in Wyoming approximately $97.9 million per year or an average overall increase of 17.3 percent. On behalf of Powder River Basin Resource Council. April 11, 2011.

REPORTS AND OP/EDS

Fisher, J. May 13, 2021. Generation and transformation: Bringing cooperative G&Ts into the clean energy future. Opinion in UtilityDive, on behalf of Sierra Club.

Fisher, J., Al Armendariz, Matthew Miller, Brendan Pierpont, Casey Roberts, Josh Smith, Greg Wannier. October 2019. Playing With Other People's Money: How Non-Economic Coal Operations Distort Energy Markets. Sierra Club.

Varadarajan, U., D. Posner, **J. Fisher.** 2018. Harnessing Financial Tools to Transform the Electric Sector. Sierra Club.

February 6, 2018. Sierra Club Comments on Puerto Rico Federal Oversight Board's Critical Infrastructure Project, Peaking Projects.

February 6, 2018. Sierra Club Comments on Puerto Rico Federal Oversight Board's Critical Infrastructure Project, Arecibo Incinerator.

June 12, 2018. Sierra Club Comments on Puerto Rico Federal Oversight Board's Critical Infrastructure Project, Peaking Projects.

Fisher, J. 2017. Sierra Club Preliminary and Reply Comments on PacifiCorp's 2017 Integrated Resource Plan. Synapse Energy Economics for Sierra Club.

Fisher J. Allison, A. 2017. Sierra Club Comments on Tucson Electric Power's 2017 Integrated Resource Plan. Synapse Energy Economics for Sierra Club.

Allison, A., **J. Fisher.** 2017. Sierra Club Comments on Arizona Public Service Company's 2017 Integrated Resource Plan. Synapse Energy Economics for Sierra Club.

Fisher, J. 2017. *Chasing the Elusive Benefits of Navajo Generating Station: A Review of Peabody & Navigant's Navajo Economic Assessment.* Prepared for Sierra Club, May 2, 2017

Fisher, J. and A. I. Horowitz. 2016. *Expert Report: State of PREPA's System, Load Forecast, Capital Budget, Fuel Budget, Purchased Power Budget, Operations Expense Budget.* Prepared for the Puerto Rico Energy Commission regarding Matter No. CEPR-AP-2015-0001, November 23, 2016.

Fisher, J., P. Luckow, A. Horowitz, T. Comings, A. Allison, E.A. Stanton, S. Jackson, K. Takahashi. 2016. *Michigan Compliance Assessment for the Clean Power Plan: MPSC/MDEQ EPA 111(d) Impact Analysis.* Prepared for Michigan Public Service Commission, Michigan Department of Environmental Quality, and Michigan Agency for Energy.

Comings, T., S. Jackson**, J. Fisher.** 2016. *The Economic Case for Retiring North Valmy Generating Station*. Synapse Energy Economics for Sierra Club.

Fisher, J., A. Horowitz, J. Migden-Ostrander, T. Woolf. 2016. *Puerto Rico Electric Power Authority's 2015 Integrated Resource Plan*. Prepared for Puerto Rico Energy Commission.

Luckow, P., E.A. Stanton, S. Fields, W. Ong, B. Biewald, S. Jackson, **J. Fisher**. 2016. *Spring 2016 National Carbon Dioxide Price Forecast*. Synapse Energy Economics.

Fisher, J., N. Santen, P. Luckow, F. De Sisternes, T. Levin, A. Botterud. 2016. *A Guide to Clean Power Plan Modeling Tools: Analytical Approaches for State Plan CO_2 Performance Projections*. Prepared by Synapse Energy Economics and Argonne National Library.

Jackson, S., **J. Fisher**, B. Fagan, W. Ong. 2016. *Beyond the Clean Power Plan: How the Eastern Interconnection Can Significantly Reduce CO_2 Emissions and Maintain Reliability.* Prepared by Synapse Energy Economics for the Union of Concerned Scientists.

Fisher, J., R. DeYoung, N. R. Santen. 2015. *Assessing the Emission Benefits of Renewable Energy and Energy Efficiency Using EPA's Avoided Emissions and generation Tool (AVERT).* Prepared for 2015 International Emission Inventory Conference.

Fisher, J., P. Luckow, N. R. Santen. 2015. *Review of the Use of the System Optimizer Model in PacifiCorp's 2015 IRP.* Synapse Energy Economics for Sierra Club, Western Clean Energy Campaign, Powder River Basin Resource Council, Utah Clean Energy, and Idaho Conservation League.

Fisher, J., T. Comings, F. Ackerman, S. Jackson. 2015. *Clearing Up the Smog: Debunking Industry Claims that We Can't Afford Healthy Air.* Synapse Energy Economics for Earthjustice.

Biewald, B., J. Daniel, **J. Fisher**, P. Luckow, A. Napoleon, N. R. Santen, K. Takahashi. 2015. *Air Emissions Displacement by Energy Efficiency and Renewable Energy.* Synapse Energy Economics.

Takahashi, K., **J. Fisher**, T. Vitolo, N. R. Santen. 2015. *Review of TVA's Draft 2015 Integrated Resource Plan*. Synapse Energy Economics for Sierra Club.

Luckow, P., E. A. Stanton, S. Fields, B. Biewald, S. Jackson, **J. Fisher**, R. Wilson. 2015. *2015 Carbon Dioxide Price Forecast.* Synapse Energy Economics.

Vitolo, T., **J. Fisher**, J. Daniel. 2015. *Dallman Units 31/32: Retrofit or Retire?* Synapse Energy Economics for the Sierra Club.

Vitolo, T., **J. Fisher**, K. Takahashi. 2014. *TVA's Use of Dispatchability Metrics in Its Scorecard.* Synapse Energy Economics for Sierra Club.

Luckow, P., E. A. Stanton, B. Biewald, S. Fields, S. Jackson, **J. Fisher**, F. Ackerman. 2014. *CO_2 Price Report, Spring 2014: Includes 2013 CO_2 Price Forecast.* Synapse Energy Economics.

Daniel, J., T. Comings, **J. Fisher**. 2014. *Comments on Preliminary Assumptions for Cleco's 2014/2015 Integrated Resource Plan.* Synapse Energy Economics for Sierra Club.

Fisher, J., T. Comings, and D. Schlissel. 2014. *Comments on Duke Energy Indiana's 2013 Integrated Resource Plan*. Synapse Energy Economics and Schlissel Consulting for Mullet & Associates, Citizens Action Coalition of Indiana, Earthjustice, and Sierra Club.

Fisher, J., P. Knight, E. A. Stanton, and B. Biewald. 2014. *Avoided Emissions and Generation Tool (AVERT): User Manual*. Version 1.0. Synapse Energy Economics for the U.S. Environmental Protection Agency.

Luckow, P., E. A. Stanton, B. Biewald, **J. Fisher**, F. Ackerman, E. Hausman. 2013. *2013 Carbon Dioxide Price Forecast.* Synapse Energy Economics.

Knight, P., E. A. Stanton, **J. Fisher**, B. Biewald. 2013. *Forecasting Coal Unit Competitiveness: Coal Retirement Assessment Using Synapse's Coal Asset Valuation Tool (CAVT).* Synapse Energy Economics for Energy Foundation.

Takahashi, K., P. Knight, **J. Fisher**, D. White. 2013. *Economic and Environmental Analysis of Residential Heating and Cooling Systems: A Study of Heat Pump Performance in U.S. Cities*. Proceeding of the 7th International Conference on Energy Efficiency in Domestic Appliances and Lighting (EEDAL'13), September 12, 2013.

Fagan, R., **J. Fisher**, B. Biewald. 2013. *An Expanded Analysis of the Costs and Benefits of Base Case and Carbon Reduction Scenarios in the EIPC Process.* Synapse Energy Economics for the Sustainable FERC Project.

Fisher, J. *Sierra Club's Preliminary Comments on PacifiCorp 2013 Integrated Resource Plan.* Oregon Docket LC 57. Synapse Energy Economics for Sierra Club.

Fisher, J., T. Vitolo. 2012. *Assessing the Use of the 2011 TVA Integrated Resource Plan in the Retrofit Decision for Gallatin Fossil Plant.* Synapse Energy Economics for Sierra Club.

Fisher, J., K. Takahashi. 2012. *TVA Coal in Crisis: Using Energy Efficiency to Replace TVA's Highly Non-Economic Coal Units*. Synapse Energy Economics for Sierra Club.

Fisher J., S. Jackson, B. Biewald. 2012. *The Carbon Footprint of Electricity from Biomass: A Review of the Current State of Science and Policy*. Synapse Energy Economics.

Fisher, J., C. James, N. Hughes, D. White, R. Wilson, and B. Biewald. 2011. *Emissions Reductions from Renewable Energy and Energy Efficiency in California Air Quality Management Districts.* Synapse Energy Economics for California Energy Commission.

Fisher, J., F. Ackerman. 2011*. The Water-Energy Nexus in the Western States: Projections to 2100*. Synapse Energy Economics for Stockholm Environment Institute.

Averyt, K., **J. Fisher**, A. Huber-Lee, A. Lewis, J. Macknick, N. Madden, J. Rogers, S. Tellinghuisen. 2011. *Freshwater use by US power plants: Electricity's thirst for a precious resource.* Union of Concernered Scientists for the Energy and Water in a Warming World Initiatve.

White, D. E., D. Hurley, **J. Fisher**. 2011. *Economic Analysis of Schiller Station Coal Units*. Synapse Energy Economics for Conservation Law Foundation.

Fisher, J., R. Wilson, N. Hughes, M. Wittenstein, B. Biewald. 2011. *Benefits of Beyond BAU: Human, Social, and Environmental Damages Avoided Through the Retirement of the US Coal Fleet*. Synapse Energy Economics for Civil Society Institute.

Fisher, J., B. Biewald. 2011. *Environmental Controls and the WECC Coal Fleet: Estimating the forward-going economic merit of coal-fired power plants in the West with new environmental controls.* Synapse Energy Economics for Energy Foundation and Western Grid Group.

Hausman, E., V. Sabodash, N. Hughes, **J. Fisher**. 2011. *Economic Impact Analysis of New Mexico's Greenhouse Gas Emissions Rule*. Synapse Energy Economics for New Energy Economy.

Fisher, J. 2011. *A Green Future for Los Angeles Department of Water and Power: Phasing out Coal in LA by 2020.* Synapse Energy Economics for Sierra Club.

Fisher, J., J. Levy, Y. Nishioka, P. Kirshen, R. Wilson, M. Chang, J. Kallay, C. James. 2010*. Co-Benefits of Energy Efficiency and Renewable Energy in Utah: Air Quality, Health and Water Benefits.* Synapse Energy Economics, Harvard School of Public Health, Tufts University for State of Utah Energy Office.

Biewald, B., D. White, **J. Fisher**, M. Chang, L. Johnston. 2009. *Incorporating Carbon Dioxide Emissions Reductions in Benefit Calculations for Energy Efficiency: Comments on the Department of Energy's Methodology for Analysis of the Proposed Lighting Standard.* Synapse Energy Economics for the New York Office of Attorney General.

Hausman, E., **J. Fisher**, L.A. Mancinelli, B. Biewald. 2009. *Productive and Unproductive Costs of CO_2 Cap-and-Trade: Impacts on Electricity Consumers and Producers.* Synapse Energy Economics for the National Association of Regulatory Utility Commissioners, The National Association of State Utility Consumer Advocates (NASUCA), The National Rural Electric Cooperative Association (NRECA), The American Public Power Association (APPA).

Biewald, B., **J. Fisher**, C. James, L. Johnston, D. Schlissel, R. Wilson. 2009. *Energy Future: A Green Energy Alternative for Michigan*. Synapse Energy Economics for Sierra Club.

James, C., **J. Fisher**, K. Takahashi. 2009. "Energy Supply and Demand Sectors." *Alaska Climate Change Strategy's Mitigation Advisory Group Final Report: Greenhouse Gas Inventory and Forecast and Policy Recommendations Addressing Greenhouse Gas Reduction in Alaska. Submitted to the Alaska Climate Change Sub-Cabinet.* Synapse Energy Economics for the Center for Climate Strategies.

James, C., **J. Fisher**, K. Takahashi, B. Warfield. 2009. *No Need to Wait: Using Energy Efficiency and Offsets to Meet Early Electric Sector Greenhouse Gas Targets*. Synapse Energy Economics for Environmental Defense Fund.

James, C., **J. Fisher**. 2008. *Reducing Emissions in Connecticut on High Electric Demand Days (HEDD)*. Synapse Energy Economics for the Connecticut Department of Environmental Protection and the US Environmental Protection Agency.

Napoleon, A., **J. Fisher**, W. Steinhurst, M. Wilson, F. Ackerman, M. Resnikoff. 2008. *The Real Costs of Cleaning up Nuclear Waste: A Full Cost Accounting of Cleanup Options for the West Valley Nuclear Waste Site.* Synapse Energy Economics et al.

James, C., F. Fisher. 2008. *Reducing Emissions in Connecticut on High Electric Demand Days (HEDD).* Synapse Energy Economics for the CT Department of Environmental Protection and the U.S. Environmental Protection Agency.

Hausman, E., **J. Fisher**, B. Biewald. 2008. *Analysis of Indirect Emissions Benefits of Wind, Landfill Gas, and Municipal Solid Waste Generation*. Synapse Energy Economics for US. Environmental Protection Agency.

Schlissel, D., **J. Fisher**. 2008. *A preliminary analysis of the relationship between CO_2 emission allowance prices and the price of natural gas.* Synapse Energy Economics for Energy Foundation.

PEER-REVIEWED ARTICLES

Buonocore, J. J., P. Luckow, **J. Fisher**, W. Kempton, J. I. Levy. 2016. "Health and climate benefits of offshore wind facilities in the Mid-Atlantic United States." *Environmental Research Letters*, 11 (2016) 074019. doi: 10.1088/1748-9326/11/7/074019

Buonocore, J. J., P. Luckow, G. Norris, J. D. Spengler, B. Biewald, **J. Fisher**, J. I. Levy. 2015. "Health and climate benefits of different energy-efficiency and renewable energy choices." *Nature Climate Change,* August 2015: doi:10.1038/nclimate2771.

Ackerman, F., **J.I. Fisher**. 2013. "Is there a water–energy nexus in electricity generation? Long-term scenarios for the western United States." *Energy Policy,* August: 235–241.

Averyt, K., J. Macknick, J. Rogers, N. Madden, **J. Fisher**, J.R. Meldrum, and R. Newmark. 2012. "Water use for electricity in the United States: An analysis of reported and calculated water use information for 2008." *Environmental Research Letters.* In press (accepted Nov. 2012).

Morisette, J. T., A. D. Richardson, A. K. Knapp, **J.I. Fisher**, E. Graham, J. Abatzoglou, B.E. Wilson, D. D. Breshears, G. M. Henebry, J. M. Hanes, and L. Liang. 2009. "Tracking the rhythm of the seasons in the face of global change: Challenges and opportunities for phenological research in the 21st Century." *Frontiers in Ecology* 7 (5): 253–260.

Biewald, B., L. Johnston, **J. Fisher**. 2009. "Co-benefits: Experience and lessons from the US electric sector." *Pollution Atmosphérique,* April 2009: 113-120.

Fisher, J.I., G.C. Hurtt, J.Q. Chambers, Q. Thomas. 2008. "Clustered disturbances lead to bias in large-scale estimates based on forest sample plots." *Ecology Letters* 11 (6): 554–563.

Chambers, J.Q., **J.I. Fisher**, H. Zeng, E.L. Chapman, D.B. Baker, and G.C. Hurtt. 2007. "Hurricane Katrina's Carbon Footprint on US Gulf Coast Forests." *Science* 318 (5853): 1107. DOI: 10.1126/science.1148913.

Fisher, J.I., A.D. Richardson, and J.F. Mustard. 2007. "Phenology model from surface meteorology does not capture satellite-based greenup estimations." *Global Change Biology* 13:707–721.

Fisher, J.I., J.F. Mustard. 2007. "Cross-scalar satellite phenology from ground, Landsat, and MODIS data." *Remote Sensing of Environment* 109:261–273.

Fisher, J.I., J.F. Mustard, and M. Vadeboncoeur. 2006. "Green leaf phenology at Landsat resolution: Scaling from the field to the satellite." *Remote Sensing of Environment* 100 (2): 265–279.

Fisher, J.I., J.F. Mustard. 2004. "High spatial resolution sea surface climatology from Landsat thermal infrared data." *Remote Sensing of Environment* 90:293–307.

Fisher, J.I., J. F. Mustard, and P. Sanou. 2004. "Policy imprints in Sudanian forests: Trajectories of vegetation change under land management practices in West Africa." *Submitted, International Remote Sensing.*

Fisher, J.I., S.J. Goetz. 2001. "Considerations in the use of high spatial resolution imagery: an applications research assessment." Proceedings at the American Society for Photogrammetry and Remote Sensing (ASPRS) Conference in St. Louis, MO.

SELECTED ABSTRACTS

Fisher, J.I., "Phenological indicators of forest composition in northern deciduous forests." *American Geophysical Union.* San Francisco, CA. December 2007.

Fisher, J.I., A.D. Richardson, and J.F. Mustard. "Phenology model from weather station meteorology does not predict satellite-based onset." *American Geophysical Union.* San Francisco, CA. December 2006.

Chambers, J., **J.I. Fisher**, G Hurtt, T. Baker, P. Camargo, R. Campanella, *et al.*, "Charting the Impacts of Disturbance on Biomass Accumulation in Old-Growth Amazon Forests." *American Geophysical Union.* San Francisco, CA. December 2006.

Fisher, J.I., A.D. Richardson, and J.F. Mustard. "Phenology model from surface meteorology does not capture satellite-based greenup estimations." *American Geophysical Union. Eos Trans. 87(52).* San Francisco, CA. December 2006.

Fisher, J.I., J.F. Mustard, and M. Vadeboncoeur. "Green leaf phenology at Landsat resolution: scaling from the plot to satellite." *American Geophysical Union. Eos Trans. 86(52).* San Francisco, CA. December 2005.

Fisher, J.I., J.F. Mustard. "Riparian forest loss and landscape-scale change in Sudanian West Africa." *Ecological Association of America*. Portland, Oregon. August 2004.

Fisher, J.I., J.F. Mustard. "High spatial resolution sea surface climatology from Landsat thermal infrared data." *American Society for Photogrammetry and Remote Sensing (ASPRS) New England Region Technical Meeting*. Kingston, Rhode Island. November, 2004.

Fisher, J.I., J.F. Mustard, and P. Sanou. "Trajectories of vegetation change under controlled land-use in Sudanian West Africa." *American Geophysical Union*. *Eos Trans. 85(47).* San Francisco, CA. December 2004.

Fisher, J.I., J.F. Mustard. "Constructing a climatology of Narragansett Bay surface temperature with satellite thermal imagery." *The Rhode Island Natural History Survey Conference*. Cranston, RI. March, 2003.

Fisher, J.I., J.F. Mustard. "Constructing a high resolution sea surface climatology of Southern New England using satellite thermal imagery." *New England Estuarine Research Society.* Fairhaven, MA. May, 2003.

Fisher, J.I., J.F. Mustard. "High spatial resolution sea surface climatology from Landsat thermal infrared data." *Ecological Society of America Conference.* Savannah, GA. August, 2003.

Fisher, J.I., S.J. Goetz. "Considerations in the use of high spatial resolution imagery: an applications research assessment." *American Society for Photogrammetry and Remote Sensing (ASPRS) Conference Proceedings*, St. Louis, MO. March, 2001.

SEMINARS AND PRESENTATIONS

Fisher, J. 2015. "Planning for Clean Power Plan: Top Five Points for States." Presentation at the National Governor's Association Policy Academy on Clean Power Plan in Salt Lake City, UT, October 14, 2015.

Fisher, J. 2015. "Environmental Regulations in Integrated Resource Planning." Presentation at EUCI Conference in Atlanta, GA, May 14, 2015.

Fisher, J.I., R. DeYoung. 2015. "EPA's AVERT: Avoiding Emissions from the Electric Sector through Efficiency and Renewable Energy." Presentation at the 18th Annual Energy, Utility & Environment Conference & Expo (EUEC2015) in San Diego, CA, February 17, 2015.

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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **INDIANA MICHIGAN POWER COMPANY** for approval to implement a power supply cost recovery plan for the 12 months ending December 31, 2021.	))))))	Case No. U-20804

At the November 18, 2021 meeting of the Michigan Public Service Commission in Lansing, Michigan.

PRESENT: Hon. Daniel C. Scripps, Chair
Hon. Tremaine L. Phillips, Commissioner
Hon. Katherine L. Peretick, Commissioner

ORDER

History of Proceedings

On September 30, 2020, Indiana Michigan Power Company (I&M) filed an application, with supporting testimony and exhibits, pursuant to Section 6j of Public Act 304 of 1982 (Act 304) as amended, MCL 460.6j, requesting approval of its proposed 2021 power supply cost recovery (PSCR) plan and proposed PSCR factor.

A prehearing conference was held on November 19, 2020, before Administrative Law Judge Sharon L. Feldman (ALJ)[1], at which Sierra Club and the Michigan Department of Attorney

[1] Administrative Law Judge Sharon L. Feldman presided over the pre-hearing conference in this proceeding in place of Administrative Law Judge Kandra K. Robbins who presided over the remainder of the proceeding. The abbreviation of Administrative Law Judge (ALJ) in this order refers to Kandra K. Robbins from this point forward.

General (Attorney General) were granted intervention. I&M and the Commission Staff (Staff) also participated in the proceeding. On December 22, 2020, the ALJ entered a protective order.

On March 12, 2021, the Staff and Sierra Club filed testimony and exhibits, and on April 9, 2021, I&M filed rebuttal testimony and exhibits. An evidentiary hearing was held on April 28, 2021. I&M, Sierra Club, and the Staff filed initial briefs on May 27, 2021. The same parties filed reply briefs on June 24, 2021.

On August 2, 2021, the ALJ issued a Proposal for Decision (PFD). On August 23, 2021, I&M filed exceptions to the PFD. On September 7, 2021, the Staff and Sierra Club filed replies to exceptions. The record in this case is comprised of 387 pages of transcript and 57 exhibits admitted into evidence.

Applicable Law

A PSCR proceeding concerns the recovery of a utility's power supply costs on an annual basis. A power supply cost recovery clause is:

> a clause in the electric rates or rate schedule of an electric utility that permits the monthly adjustment of rates for power supply to allow the utility to recover the booked costs . . . of fuel burned by the utility for electric generation and the booked costs of purchased and net interchanged power transactions by the utility incurred under reasonable and prudent policies and practices.

MCL 460.6j(1)(b). A power supply cost recovery factor is "that element of the rates to be charged for electric service to reflect power supply costs incurred by an electric utility and made pursuant to a power supply cost recovery clause incorporated into the rates or rate schedule of an electric utility." MCL 460.6j(1)(c). Subsection 6j(3) of Act 304 requires a utility with a PSCR clause to annually file a PSCR plan describing the expected sources of electric power supply and changes in the cost of power supply anticipated over the 12-month period following the filing of the plan. The PSCR plan must also describe all major contract and power supply agreements for the 12-

month period. A utility must contemporaneously file "a 5-year forecast of the power supply requirements of its customers, its anticipated sources of supply, and projections of power supply costs, in light of its existing sources of electrical generation and sources of electrical generation under construction." MCL 460.6j(4).

Subsection 6j(5) of Act 304 provides that, after a utility files its PSCR plan and five-year forecast, the Commission shall conduct a proceeding to evaluate the reasonableness and prudence of the PSCR plan and to establish PSCR factors for the period covered by the plan. In its final order in a PSCR plan case, the Commission must "evaluate the reasonableness and prudence of the decisions underlying the [PSCR] plan" and must "approve, disapprove, or amend the plan accordingly." MCL 460.6j(6).

In evaluating the decisions underlying the PSCR plan, Subsection 6j(6) of Act 304 states that "the commission shall consider the cost and availability of the electrical generation available to the utility; the cost of short-term firm purchases available to the utility; the availability of interruptible service; . . . whether the utility has taken all appropriate actions to minimize the cost of fuel; and other relevant factors." This subsection also requires the Commission to approve, reject, or amend the 12 monthly power supply cost recovery factors requested by the utility in its PSCR plan. The finalized PSCR factors shall not reflect items the Commission could reasonably anticipate would be disallowed in a PSCR reconciliation proceeding. MCL 460.6j(6).

In its final order the Commission shall also evaluate the decisions underlying the five-year forecast filed by a utility and may indicate any cost items in the five-year forecast that the Commission would be unlikely to permit the utility to recover from its customers in rates, rate schedules, or PSCR factors established in the future. MCL 460.6j(7). This is known as a Section 7 warning.

Positions of the Parties

I&M requested that the Commission enter an order approving implementation of the company's proposed PSCR plan and PSCR factor in rates for 2021 jurisdictional sales of electricity that are subject to the PSCR clause. I&M requested that the Commission approve the company's request for a 2021 PSCR factor of 18.92 mills per kilowatt-hour (kWh), resulting in a proposed Michigan jurisdictional PSCR factor of 2.85 mills per kWh applicable to the billing months of January 2021 through December 2021. I&M requested that the Commission accept the company's five-year forecast and reject the request to issue a Section 7 warning pursuant to MCL 460.6j(7). I&M's initial brief, pp. 21-22.

I&M argued that, in accordance with Act 304, its proposed 2021 PSCR plan contains all the elements which are required to be included and described in a PSCR plan. I&M contended that the proposed 2021 PSCR plan is reasonable and prudent. I&M argued that it has taken all appropriate actions to minimize the cost of fuel. The company argued that the proposed 2021 PSCR factors do not reflect items that the Commission could reasonably anticipate would be disallowed under Section 6j(13) of Act 304. *Id*.

The Staff recommended that the company's 2021 PSCR factor be approved as reasonable given that it will be reconciled and reviewed in the company's future 2021 PSCR reconciliation case. Staff's initial brief, pp. 4-5. The Staff contended that the Inter-Company Power Agreement (ICPA) costs included in the company's 2021 PSCR plan case fall within a range of reasonableness and should be approved subject to reconciliation and further review for reasonableness and prudence in a reconciliation case. *Id*., pp. 5-6.

The Staff agreed with Sierra Club that the dispatch of the Rockport units is uneconomic as "must run." However, the Staff maintained its position that the company's application in this case

is acceptable for the purposes of setting a reasonable and prudent PSCR factor in 2021. Although, considering the uneconomic must run, the Staff recommended that the Commission order the company to provide an analysis of the Rockport units' actual dispatch in the reconciliation proceeding of this case. Staff's reply brief, p. 2. The Staff recommended that if I&M fails to provide this information or provides information that does not adequately support its position to commit the Rockport units as must run, the Commission should warn the company that it may disallow fuel costs associated with uneconomic must run decisions in future reconciliation cases. *Id*.

Sierra Club recommended that the Commission determine that the ICPA is substantially higher cost than the value of the products and services provided by the Ohio Valley Electric Corporation (OVEC) to I&M and therefore, the OVEC contract is not reasonable or prudent under current market conditions for the 2021 plan year. Sierra Club's initial brief, p. 3. In addition, Sierra Club asked that the Commission find that the ICPA is projected to cost significantly more than equivalent market products and services during the forecast period of 2022 to 2025 such that it is outside the range of reasonable and prudent costs. *Id*. Sierra Club recommended that the Commission amend the PSCR plan by removing the costs of the ICPA from the maximum PSCR factor and reduce I&M's forecast costs by the difference between OVEC's expected costs and the expected cost of market purchases for energy and capacity during that time period. *Id*., p. 4. Sierra Club requested the Commission issue a Section 7 warning to I&M that based on present evidence it will likely disallow I&M's recovery of the Michigan jurisdictional share of compensation for the ICPA in 2022-2025. *Id*. Sierra Club argued that the Commission should reaffirm that OVEC is an affiliate of I&M under the Michigan Code of Conduct (Mich Admin Code, R 460.10101 *et seq*.), and the Commission should apply the Code of Conduct's affiliate

price cap. Applying the affiliate price cap would direct a disallowance equal to the difference between the payments I&M makes under the ICPA and the costs that I&M ratepayers would pay for the same amount of energy and capacity at market prices. *Id*.

Finally, the Sierra Club contended that the Commission should warn I&M that it will disallow recovery in PSCR reconciliation dockets of the fuel portion of all net revenue losses incurred because of imprudent unit commitment decisions at the Rockport units. *Id*.

Proposal for Decision

The ALJ provided an overview of the record and positions of the parties on pages 2-34 of the PFD which are summarized here for reference. The ALJ also provided an overview of the applicable regulations under Act 304. As the ALJ states, "[t]he Company bears the burden of proof in an Act 304 proceeding to demonstrate that its proposed PSCR factors are reasonable and prudent. The applicable standard of proof for purposes of determining whether they are reasonable and prudent is the preponderance of the evidence standard." PFD, p. 34. The PFD recommended that the Commission:

> 1. Apply the affiliate price cap and direct [a] disallowance equal to the difference between I&M's payments under the ICPA and the costs I&M ratepayers would pay for the same amount of energy and capacity at market prices.
>
> 2. Direct that the PSCR plan should be amended to remove the costs of the OVEC ICPA from the maximum PSCR factor and reduce I&M's forecast costs by the difference between OVEC's expected costs and the expected cost of market purchases for energy and capacity.
>
> 3. Amend the plan to include the impact of the Rockport Unit 2 purchase in the forecasting of costs.
>
> 4. Warn I&M that it will disallow recovery in PSCR reconciliation dockets of the fuel portion of all net revenue losses incurred as a result of imprudent unit commitment decisions at Rockport.

PFD, p. 40.

Exceptions and Replies to Exceptions

I&M takes exception to the PFD on seven points: (1) the ALJ failed to acknowledge the Commission's findings in Case Nos. U-20529 and U-20224, (2) the ALJ did not analyze the reasonableness and prudence of I&M's projected ICPA costs as required under MCL 460.6j, (3) the ALJ erred in recommending removal of ICPA costs from the PSCR factor by misapplying MCL 460.6j(6), (4) the ALJ erred in recommending applying the Code of Conduct's pricing provision in I&M's 2021 PSCR plan case, (5) the ALJ substantively misapplied the Code of Conduct by ignoring requirements set forth in Section 4 of Mich Admin Code, R 460.10108 (Rule 8), (6) the ALJ erred in recommending the PSCR plan be amended to include the impact of I&M's planned purchase of Rockport Unit 2 in the forecasting of costs, and (7) the ALJ erred in recommending that I&M be warned the Commission will disallow recovery in PSCR reconciliations of the fuel portion of all net revenue losses incurred as a result of imprudent unit commitment decisions at the Rockport units. *See*, I&M's exceptions, pp. 9-42.

In replies to exceptions, Sierra Club asks that the ALJ's decision be affirmed and adopted by the Commission. Sierra Club contends that the issues regarding I&M's 2021 PSCR plan have not been presented to the Commission for consideration or decided by the Commission because the issues were not ripe for decision until this proceeding. Sierra Club argues that the Commission could not previously determine the following issues presented in this case: (1) whether I&M's 2021 PSCR costs were reasonable and prudent, (2) whether OVEC costs in the 2021-2025 forecast warrant a Section 7 warning, and (3) whether OVEC 2021 PSCR costs comply with the Code of Conduct. Sierra Club states that it has:

> heeded the Commission's instruction in Case No. U-20529, which stated that "the comparison to the PJM [Interconnection, LLC] (PJM) capacity market is insufficient, on its own, to warrant a disallowance," and presented substantial evidence about why the OVEC costs were unreasonable that was not part of the record in Case Nos. U-20529 and U-20224−including [American Electric Power]'s (AEP's) own PJM capacity market forecast, the price the Company recently paid to purchase Rockport unit 2, and [Cost of New Entry](CONE) as calculated by PJM.

Sierra Club's replies to exceptions, p. 9.

Sierra Club argues that the ALJ's recommendations in this case are consistent with the Commission's orders in Case Nos. U-20529 and U-20224 and are the logical continuation of the orders in those cases. Sierra Club quotes the May 13 order in Case No. U-20529 (May 13 order), stating:

> However, on a going forward basis, the Commission will closely scrutinize costs incurred under this contract between affiliates, reminds I&M of its obligations under the Code of Conduct, including I&M's "continuing duty to support its long-term contracts and affiliate transactions," and "will expect to see evidence that the company has taken steps to minimize the cost of [power], including efforts to renegotiate contracts, and will look to comparisons with other long-term supply options as informative as to whether this particular contract adheres to the Code of Conduct."

May 13 order, pp. 18-19 (alteration in original) (citing the April 8, 2021 order in Case No. U-20543 (April 8 order), pp. 6-7).

Sierra Club goes on to argue that the issue of whether I&M is an affiliate of OVEC has been conclusively decided in Case No. U-20529 and that this decision was reiterated in Case No. U-20224. Sierra Club also notes that the Commission has already addressed the issues of federal preemption, the reasonable utility standard, and issue preclusion under *Pennwalt Corp v Pub Serv Comm*, 166 Mich App 1, 9; 420 NW2d 156 (1988).

Sierra Club posits that the ALJ's recommendations are based on the Commission's Code of Conduct, not the reasonableness and prudence language of MCL 460.6j alone. Sierra Club argues that while Subsection 6j of Act 304 applies to all decisions and projected costs in a PSCR plan, a

determination of compliance with the Code of Conduct price cap applies only to affiliate transactions. Sierra Club's replies to exceptions, pp. 23-24.

Sierra Club contests I&M's assertion that contracts are not subject to review of their costs from year-to-year. Sierra Club cites to the language of the May 13 order, which stated "[m]erely approving recovery of costs under the ICPA does not amount to a finding that the ICPA, and all future costs, are reasonable," and that "the Commission also has a duty under the statute to continuously evaluate the reasonableness of the PSCR and factors, including the cost arising under the ICPA and its amendments." Sierra Club's replies to exceptions, p. 25 (citing May 13 order, pp. 13-14).

Sierra Club argues that the Code of Conduct is within the purview of "other relevant factors" that the Commission must consider when it approves, disapproves, or amends a PSCR plan. Sierra Club asserts that the Code of Conduct governs the permissible prices regulated utilities may pay their affiliates and is a relevant factor when the PSCR plan includes buying substantial amounts of power from an affiliate. Sierra Club's replies to exceptions, p. 27. Sierra Club points out that:

> [i]n practice, the Commission has repeatedly removed costs from PSCR factors based on items other than those listed in subsection (13). These items have included projected costs of natural gas that were too high; projected coal costs that were too high; and projected power supply costs resulting from a projected random outage rate that was too high.

Sierra Club's replies to exceptions, p. 28 (citing the July 22, 1992 order in Case No. U-9960, pp. 23-25).

Sierra Club replies to I&M's exception that the ALJ's decision is inconsistent with the PSCR plan and reconciliation processes established in MCL 460.6j. I&M argues that the Commission should reject the PFD's approach and review the difference between the company's projections and actual data in the reconciliation process. I&M's exceptions, p. 4. Sierra Club replies that the

Commission should reject this contention as it would be "inconsistent with the statute and with prior Commission decisions, which have reduced PSCR factors when a cost is too high rather than waiting for the reconciliation." Sierra Club's replies to exceptions, p. 29.

Sierra Club contests I&M's assertion that "the Commission's stated intention that it will only scrutinize ICPA costs under the Code of Conduct for newly filed cases must also apply to the present PSCR Plan case." I&M's exceptions, p. 25. Sierra Club argues that nowhere in the May 13 order does the Commission state that the Code of Conduct will only apply to newly filed proceedings as I&M implies. Sierra Club's replies to exceptions, p. 31. Sierra Club states that "[t]he fact that the Commission declined to issue a Section 7 warning in a plan case—in part because the reconciliation for that same year had already been filed does not equate to a holding by the Commission that the Code of Conduct will not apply to OVEC costs in any other I&M case filed before the Order in U-20529 was issued." Sierra Club's replies to exceptions, p. 32. Sierra Club argues that I&M's due process arguments are invalid because "the Company was free to put forward any OVEC-related evidence it wanted to." *Id*., p. 34.

Sierra Club replies to I&M's exception to the ALJ's determination that I&M and OVEC are affiliates and therefore purchases under the ICPA are subject to the Code of Conduct. Sierra Club argues that this exception is an attempt to relitigate an issue that the Commission has already decided in the May 13 order and reaffirmed in the June 23, 2021 order in Case No. U-20224 (June 23 order). *Id*., p. 34. Sierra Club reiterates its original positions on the affiliate relationship between I&M and OVEC. Sierra Club posits that the Commission has rejected I&M's assertions that the August 28, 2018 order in Case No. U-18361 (August 28 order) and federal preemption arguments are determinative in this case. *Id*., pp. 37-41.

Sierra Club rejects I&M's assertion that:

> the PFD substantively misapplied the requirements set forth in Rule 8(4) by concluding, without sufficient legal analysis or evidentiary support, that, if OVEC is an affiliate, then the Code of Conduct's price cap mandates a direct disallowance equal to the difference between I&M's payments under the ICPA and the costs I&M customers would pay for the same amount of energy and capacity at market prices.

I&M's exceptions, p. 36. Sierra Club replies that the proper application of Rule 8(4) would not be to apply the pricing provision that governs utilities providing services to affiliates, which bases compensation on the higher of fully allocated embedded costs or fair market price, but to apply the provision that governs purchases of services or products from an affiliate, which states:

> If an affiliate or other entity within the corporate structure provides services or products to a utility, and the cost of the service or product is not governed by section 10ee(8) of 2016 PA 341, MCL 460.10ee(8), compensation is at the lower of market price or 10% over fully allocated embedded cost.

Sierra Club's replies to exceptions, p. 42 (citing Rule 8(4)).

Sierra Club replies to I&M's exception that the ALJ erred in recommending that the PSCR plan be amended to include the impact of the company's planned purchase of Rockport Unit 2 in the forecasting of costs. Sierra Club argues that because I&M has agreed to purchase Rockport Unit 2, the output will be paid for by Michigan customers, and because the purchase cost has been included in the record for this case, the inclusion of the Rockport Unit 2 purchase cost in the analysis of this case is reasonable. Sierra Club's replies to exceptions, p. 43. Additionally, Sierra Club replies that the ALJ is correct to warn I&M about imprudent self-scheduling of the Rockport units. *Id*., pp. 43-44.

The Staff filed replies to exceptions on three points. The Staff concurs with I&M that the ALJ improperly failed to address whether the projected 2021 ICPA costs fall within an acceptable range of reasonableness. Staff's replies to exceptions, p. 2. The Staff concurs with I&M that Commission precedent dictates that cost recovery related to ICPA/OVEC should occur after the

upcoming integrated resource plan (IRP) and subsequent PSCR proceedings. *Id*., p. 3. Lastly, the Staff agrees with I&M that a Section 7 warning in this case would be improper. *Id*., p. 4. The Staff concludes by reiterating its position that I&M's 2021 PSCR factor presented in this case is reasonable and should be approved by the Commission.

Discussion

The exceptions filed in this case raise two contested issues. The first is the classification of I&M as an affiliate of OVEC and the application of the Commission's Code of Conduct. The second is the operation of the Rockport units and the purchase of Rockport Unit 2. The Commission will address each issue in turn.

A. Ohio Valley Electric Corporation Inter-Company Power Agreement

I&M's PSCR plan includes costs associated with the purchase of power from OVEC under the ICPA. It is uncontested that OVEC is an entity jointly owned by 12 utilities in Ohio, Indiana, Michigan, Kentucky, West Virginia, and Virginia. OVEC operates two 1950s-era coal fired power plants—Kyger Creek, a five-unit, 1,086 megawatt (MW) plant in Gallia County, Ohio, and Clifty Creek, a six-unit, 1,303 MW plant in Jefferson County, Indiana. OVEC supplies the power from these plants to utilities through a long-term contract, the ICPA. Together the utilities are responsible for the fixed and variable costs of OVEC. OVEC bills utilities a variable, demand, and transmission charge. 2 Tr 301-302. It is also uncontested that I&M is responsible for 7.85% of OVEC's fixed and variable costs and is entitled to a 7.85% share of OVEC's power output. The cost of the ICPA is passed through to I&M ratepayers as a direct cost. 2 Tr 302.

The ICPA was set to expire on December 31, 2005. Before the contract was set to expire, the sponsors to the contract (Sponsors or Sponsoring Companies) agreed to extend the terms of the

ICPA to 2026. In September 2010, the Sponsors again agreed to revise the ICPA to extend its terms until 2040. I&M and other Sponsors are obligated to cover the costs of the OVEC plants through 2040. 2 Tr 302. As the Staff testified in this case, I&M has not presented the ICPA for review by the Commission. 2 Tr 284. I&M did not seek approval from the Commission for the decision to extend the contract in 2004 or 2010. The actual costs resulting from I&M's participation in the OVEC ICPA are therefore reviewed each year in the PSCR process for reasonableness and prudence. 2 Tr 285.

1. Affiliate Status of Indiana Michigan Power Company and Ohio Valley Electric Corporation

The Commission again reaffirms its determination that an affiliate relationship exists between I&M and OVEC. I&M argues that it does not have an ownership interest in OVEC. I&M states that it is a participating member in OVEC, but its parent company, AEP, and not I&M, has an ownership interest in OVEC. This argument fails to recognize that ownership is not required under the Code of Conduct to constitute an affiliate relationship. Rule 2(1)(a) of the Commission's Code of Conduct defines an affiliate as follows:

> "Affiliate" means a person or entity that directly or indirectly through 1 or more intermediates, controls, is controlled by, or is under common control with another specified entity. As used in these rules, "control" means, whether through an ownership, beneficial, contractual, or equitable interest, the possession, directly or indirectly, of the power to direct or cause the direction of the management or policies of a person or entity or the ownership of at least 7% of an entity either directly or indirectly.

Mich Admin Code, R 460.10102 (Rule 2).

Sierra Club filed testimony to support the position that I&M is an affiliate of OVEC. As shown in the 2019 OVEC annual report, I&M is a Sponsor of the ICPA. I&M has a 7.85% OVEC power participation benefit. Three AEP Companies−Appalachian Power Company (15.69%),

I&M (7.85%), and Ohio Power Company (19.93%)−represent the largest participation block in the ICPA totaling 43.47%. AEP, the parent company of I&M, holds the largest shareholder percentage of equity in OVEC also totaling 43.47%. The participation and requirements benefits of these three companies equate to the exact equity share that AEP has in OVEC. The Commission finds that I&M holding a participation and requirements benefit that amounts to an equal level of shareholder control signifies a level of interest between the company and OVEC that meets the definition of "affiliate" found in Rule 2(1)(a) of the Commission's Code of Conduct.

Additionally, the record shows that the three subsidiaries of AEP are entitled to one vote on the OVEC Operating Committee. In replies to exceptions, I&M states:

> To the extent a Sponsoring Company may vote on any matters before the Operating Committee, which is separate from OVEC's Board of Directors, I&M currently has only one vote on the Operating Committee. Paragraph 9.05 of the Amended and Restated ICPA establishes that I&M, AEP Ohio, and Appalachian Power Company have one joint vote on the Operating Committee, "if any two or more Sponsoring Companies are Affiliates, then such Affiliates shall together be entitled to appoint only one member to the Operating Committee."

I&M's replies to exceptions, p. 29 (citing Exhibit SC-17, p. 53). In discovery, I&M stated "AEP Service Corporation participates on the Operating Committee on behalf of AEP Sponsoring Companies, including I&M." Exhibit SC-28, p. 1.

Rule 2(1)(a) of the Code of Conduct does not require that an entity directly control another specified entity to constitute being an affiliate. To the contrary, the definition of control enumerates that the interest in the specified entity may be an ownership, beneficial, contractual, or equitable interest. The definition also states that control need not be direct, but that the power to cause the direction of the management or policies of an entity amounts to an affiliate interest. As noted above, it is uncontested that I&M is entitled to a 7.85% share of OVEC's power output and is responsible for 7.85% of OVEC's fixed and variable costs. This alone would meet the

definition in the rules of a beneficial interest. The fact that I&M's participation share equates exactly to the shareholder percentage held by its parent company, AEP, and that AEP is a voting member of the OVEC Operating Committee only reinforces the affiliate relationship. As such, the Commission concludes that I&M possesses the power to cause the direction of the management or policies of OVEC. I&M is thus an affiliate of OVEC and subject to the Commission's Code of Conduct.

As an investor-owned utility that purchases power through the ICPA to serve retail customers, I&M's power purchase agreements are subject to the regulation of the Commission. I&M argues that the August 28 order regarding the applicability of the Code of Conduct to federally regulated wholesale services is determinative in the present case. Though the Commission has previously rejected this argument, it will reiterate its reasoning for the decision based on the record in this case. I&M contends that the Commission is not permitted to set the price of federally regulated wholesale contracts and that the Commission failed to follow the substance of its own promulgated rule. The Commission again finds that the transaction at issue in the present case is distinguishable from the facts and record at issue in the August 28 order.

The August 28 order addressed concerns raised by Wolverine Power Supply Cooperative, Inc. (Wolverine), a member-regulated generation and transmission cooperative, which buys power from the market to sell to wholesale customers. In the rulemaking at issue in Case No. U-18361, Wolverine suggested that the definition of utility as an electric utility "regulated by the commission" could lead to the Commission asserting jurisdiction over federally regulated electric cooperatives, such as Wolverine. As a federally regulated generation and transmission cooperative utility, Wolverine is not subject to the same regulations as an investor-owned electric utility under

Rule 2(1)(e). Thus, the Commission clarified in its rulemaking that the Code of Conduct does not apply to federally regulated wholesale services.

In the present case, however, I&M is an investor-owned utility under Rule 2(1)(e), and the power purchased through the ICPA is used to serve its retail customers. As the Commission noted in the May 13 order, "[e]xpanding the conclusions of the August 28 order to include any and all transactions−even between affiliates−that flow through regional wholesale markets or involve a contract approved by [the Federal Energy Regulatory Commission](FERC) would render meaningless the provisions of the Code of Conduct. That the Commission cannot do." May 13 order, p. 16.

As such, Commission again finds that the August 28 order is distinguishable from the case at hand, and that as an investor-owned electric utility serving retail customers in the state of Michigan, I&M is subject to the regulation of the Commission and, thus, the Commission's Code of Conduct.

I&M further argues that, even if it is deemed to be subject to the Code of Conduct,

> because the record was closed in Case No. U-20804 and the parties [briefed] this PSCR case with a record that does not contemplate the May 13 order, the Commission's stated intention that it will only scrutinize ICPA costs under the Code of Conduct for newly filed cases must also apply to the present PSCR Plan case. To hold otherwise would offend fundamental notions of due process because the Commission's May 13 Order arose during the course of this case.

I&M's replies to exceptions, p. 25. The Commission disagrees with this assertion on two points. In its May 13 order, the Commission stated that it "agree[d] with the ALJ that the comparison to the PJM capacity market is insufficient, on its own, to warrant a disallowance and finds that a Section 7 warning is not appropriate at this time, particularly given the reconciliation for the 2020 plan year has already been filed." May 13 order, p. 18. The present case differs from Case No. U-20529 in that additional evidence of appropriate market comparisons was presented on the

record. In addition, while the docket in Case No. U-20805 has been opened, the reconciliation for the 2021 plan year has not yet been filed, providing an additional important distinction between the present case and Case Nos. U-20529 and U-20224. The Commission notes that the decisions made in a PSCR plan case are applied prospectively to inform reconciliations and not retroactively to PSCR factors set in earlier plan years, and as such it is appropriate to apply the Code of Conduct to the case at hand.

Lastly, the Commission would like to address I&M's assertion that the approach put forward in the PFD will "have a chilling effect on the developing renewable market because nobody will sign long-term purchase agreements for renewables if there is a threat the Commission could disallow those costs later because the market price for energy decreases or the costs of renewables vary in the future." I&M's replies to exceptions, p. 3.

Unlike other long-term contracts involving renewables or any other generation, however, the ICPA extension has never been presented to the Commission for approval. Indeed, despite the fact that the ICPA had been extended through 2026 just six years before, and that in that time Michigan had enacted specific statutory provisions allowing an electric utility that proposes to enter into a power purchase agreement for the purchase of electric capacity for a period of six years or longer to submit an application to the Commission seeking a certificate of necessity for that investment and a portion of the costs associated with that investment are then allocable to retail customers in this state, when I&M joined other Sponsoring Companies in September 2010—sixteen years ahead of the expiration date of the extension agreed to in 2004—to further extend the ICPA through 2040, it chose not to seek Commission approval for the extension.

Public Act 3 of 1939, as amended by Public Act 286 of 2008 included the following language:

> An electric utility that proposes to. . .enter into a power purchase agreement for the purchase of electric capacity for a period of 6 years or longer may submit an

> application to the commission seeking a certificate of necessity for that construction, investment, or purchase if that construction, investment, or purchase costs $500,000,000.00 or more and a portion of the cost would be allocable to retail customers in this state.

MCL 460.6s(1). The statute then provides that "the commission shall include in an electric utility's retail rates all reasonable and prudent costs for an electric generation facility or power purchase agreement for which a certificate of necessity has been granted." MCL 460.6s(9). The statute further states "[t]he commission shall not disallow recovery of costs an electric utility incurs in . . . purchasing power pursuant to a power purchase agreement for which a certificate of necessity has been granted." *Id*. As shown in the OVEC benchmark study conducted after the contract was submitted to FERC, "the ICPA was expected to have a cost of $7.51 billion on a present value basis between the years 2011 and 2040. This means I&M's share of the contract was expected to cost $589.4 million on a present value basis in 2011." 2 Tr 310; Exhibit SC-7. I&M had the opportunity to apply for a certificate of necessity in 2010 before the contract was amended to extend its term until 2040, which would assure recovery of the contracts associated costs, and the company failed to do so.

The ICPA also remains unapproved by FERC. On March 23, 2011, OVEC filed revisions to the ICPA among OVEC and the Sponsoring Companies, and the power agreement between OVEC and Indiana Kentucky Electric Corporation. The filing was canceled and refiled on April 27, 2011, to correct the file type. The agreements reflected the extension of the terms and agreements of the ICPA from March 13, 2026, to June 30, 2040. The filing was accepted by FERC and notice was published in the Federal Register with interventions and protests due on or before May 18, 2011. No protests or adverse comments were received. According to FERC, the acceptance of this filing "does not constitute approval of any service, rate, charge, classification, or any rule, regulation, contract, or practice affecting such rate or service provided for in the filed

documents." *In re Amended and Restated Inter-Company Power Agreement and Amended and Restated OVEC-IKEK Power Agreement*, order of the Federal Energy Regulatory Commission, entered May 23, 2021 (Docket No. ER11-3181-000, *et al*). The ICPA has thus not been approved at the state level by the Commission nor at the federal level by FERC.

As the Commission stated in its December 9, 2020 order in Case No. U-20203; April 8 order; May 13 order; and June 23 order, while long-term contracts are encouraged, this does not absolve a utility from monitoring and responding to market conditions and system needs and making good faith efforts to manage existing contracts. As these orders state, such efforts may include meaningful attempts to renegotiate contract provisions to ensure continued value for ratepayers as market conditions change. As the Commission has repeatedly stated, the Commission will expect to see evidence that utilities have taken steps to minimize costs, including efforts to renegotiate contracts, and will look to comparisons with other long-term supply options as informative as to whether this particular contract adheres to the requirements of the Code of Conduct.

The Commission does not control the business judgment or decisions of utilities, but the Commission has a duty to customers to assure utilities are not subsidizing uneconomic, unreasonable, and imprudent decisions through customer rates. The Commission's decision does not prevent the company from fulfilling their contractual duties under the ICPA, but establishes what costs are appropriate to recover from ratepayers.

2. Section 7 Warning

Subsection 6j(7) of Act 304 states that in its final order in a power supply and cost review, "[t]he commission may also indicate any cost items in the 5-year forecast that, on the basis of present evidence, the commission would be unlikely to permit the utility to recover from its customers in rates, rate schedules, or power supply cost recovery factors established in the future."

The record shows that independent analyses and those conducted by OVEC Sponsors demonstrate that on a forward-looking basis the operation of the OVEC units is uneconomical. The record shows a March 2017 analysis of the ICPA by Duke Energy Ohio projected substantial net losses associated with holding a position in the ICPA. This analysis, scaled to I&M's share, suggests losses of $67 million relative to market alternatives between 2020 and 2025. 2 Tr 319-320. Moody's Analytics' December 2018 assessment of the ICPA, scaled to I&M's share, found annual losses of $16-$20 million. 2 Tr 320. Economic assessments done by Sponsoring Companies to the ICPA also demonstrate the long-term negative economics of the OVEC units. In April 2019, FirstEnergy Solutions, another ICPA Sponsor, conducted a forward-looking analysis through 2040 and found projected losses, scaled to I&M's share, of $267 million relative to market alternatives. *Id*. I&M's AEP affiliate AEP Service Corporation performed a forward-looking analysis of the ICPA in 2015 and 2016, the results of which were confidential, but were presented to OVEC's board. *Id*.

Based on the above analyses, the Commission finds that a Section 7 warning is appropriate in this case. The company is put on notice that the Commission is unlikely to permit the utility to recover these uneconomic costs from its customers in rates, rate schedules, or PSCR factors established in the future without good faith efforts to manage existing contracts such as meaningful attempts to renegotiate contract provisions to ensure continued value for ratepayers. The Commission issues a Section 7 warning that I&M may not be able to recover its full costs under the ICPA as part of the reconciliation of its 2021 PSCR plan.

3. Affiliate Price Cap

Sierra Club filed testimony and exhibits to support the position that I&M customers are paying unreasonable prices to OVEC under the ICPA. Sierra Club's Testimony, p. 3. Sierra Club

testified that "[i]f I&M can purchase the energy, capacity, or ancillary services it needs from the PJM market at a lower cost than it would pay to purchase power from OVEC under the ICPA, then it is paying above market price for the OVEC power." 2 Tr 303. Sierra Club testified that it "compared the total energy charges billed to Sponsoring Companies under the ICPA and the revenue that I&M earned selling that energy into the PJM energy market" and found that

> I&M's own data shows that in 2020 OVEC billed I&M $18,487,826 in energy charges for 721,476 MWh [megawatt hours] of electricity. That works out to an energy cost of $25.63/MWh. But I&M only earned $15,960,650 in energy and ancillary market revenue selling that energy, which works out to a value of $22.12/MWh. That means that on a marginal cost basis alone, in 2020 I&M lost $2.5 million for its ratepayers (excluding demand charge and capacity value).

2 Tr 304; PFD, pp. 20-21. Sierra Club testified that the ICPA is not delivering value to the I&M ratepayers and that "[t]he cost for power under the ICPA has been significantly above market value since at least 2017." 2 Tr 307.

Sierra Club argues that the Code of Conduct establishes requirements for transactions with affiliates, including a price cap. Sierra Club argues that the Commission should disallow excess OVEC costs in this case because I&M's payments to OVEC run afoul of the Code of Conduct's affiliate price cap. Sierra Club's reply brief, p. 6. Sierra Club contends that OVEC costs are excessive from 2017 through 2025 based on data from AEP's own PJM capacity market forecast, the price the company recently paid for Rockport Unit 2, and the CONE as calculated by PJM. *Id.*, p. 11.

In concluding that I&M and OVEC are affiliates, and that a Section 7 warning is appropriate in this case, the Commission must also address the issue of compensation. Under Section 1 of Rule 8, "[a] utility shall not discriminate in favor of or against any person, including its affiliates." Section 4 of Rule 8 further provides:

> If an affiliate or other entity within the corporate structure provides services or products to a utility, and the cost of the service or product is not governed by section 10ee(8) of 2016 PA 341, MCL 460.1033(8), compensation is at the lower of market price or 10% over fully allocated embedded cost.

Mich Admin Code, R 460.10108(4).

As a result, I&M's recovery is capped at the lessor of the market price or 10% over the fully allocated embedded cost. As previously noted, based on the record in this case the embedded cost of the ICPA is higher than the PJM market price. However, in the May 13 order, the Commission found that reviewing costs associated with a long-term contract as they relate to short-term market purchases is not an appropriate basis for comparison and a comparison to the PJM capacity market, on its own, was insufficient to warrant a disallowance of funds. May 13 order, p. 18. The Commission stated that it would look to comparisons with other long-term supply options as informative as to whether this particular contract adheres to the requirements of the Code of Conduct. Sierra Club provided three alternatives with which to compare the ICPA costs on the record in this case. While there may be other available comparisons, the Commission finds that the Rockport sale capacity value and net CONE may be appropriate proxies for calculating market price and I&M's resulting PSCR factor. There may also be legitimacy in valuing the attributes of price stability, supply certainty, and resilience afforded by a utility's Fixed Resource Requirement (FRR) alternatives to the PJM capacity market.

The Commission will look to the upcoming IRP and reconciliation filings for greater evidence on whether the market price of net CONE is the appropriate proxy, or how best to price these incremental attributes associated with FRR resources for application of the affiliate price cap. In addition, should I&M seek to use a proxy other than the capacity value of the recent sale of Rockport Unit 2, it should prefile testimony in the reconciliation addressing why the OVEC market value differs from the Rockport unit's capacity value.

The Commission recognizes that, while never approved at either the state or federal level, the OVEC ICPA is a long-term supply option, and as such, the Commission expects that it will be considered in long-term planning. The Commission agrees with the Staff's recommendation that any renegotiation efforts the company undertakes with ICPA members should be described in future IRP cases. The Commission reiterates the directive from the May 13 order that I&M shall file a comprehensive analysis regarding the ICPA with its 2021 IRP. As directed, the company shall file a net present value of the revenue requirement and model a sensitivity to its preferred course of action. The sensitivity model shall include the company's preferred course of action with and without energy and capacity purchased under the ICPA, along with a model of optimized resources to replace the ICPA resources.

B. Rockport Units 1 and 2

I&M's PSCR plan also includes the capacity of the Rockport Plant generating units. Exhibits IM-5, IM-6. The Rockport Generating Station is a two-unit coal-fired power station located in Spencer County, Indiana. Rockport Unit 1 has an expected capacity of 1,072 MW and Rockport Unit 2 has an expected capacity of 1,051 MW for the present plan year. *Id*. Rockport Unit 1 is owned in 50% shares by I&M and AEP Generating Company (AEG), and Unit 2 is leased on the same percentage basis as I&M and AEG. AEG sells 70% of its share of the power from each Rockport unit back to I&M and 30% to Kentucky Power under a Unit Power sales agreement. 2 Tr 328. I&M pays AEG under a FERC-approved power agreement that includes both energy charges and demand charges. I&M pays AEG demand charges associated with 35% of the capacity of the Rockport plant and recovers its share of demand charges from its Michigan customers in the PSCR. 2 Tr 260.

I&M's and AEG's leases of Rockport Unit 2 were set to expire in December 2022. On April 22, 2021, I&M announced its purchase of Rockport Unit 2. During cross-examination, I&M indicated that the impact of the purchase of Rockport Unit 2 by I&M and AEG was not included in any of the forecasting completed for this filing in September 2020. 2 Tr 254.

Sierra Club testifies that I&M has operated, and continues to operate, the two Rockport units uneconomically. Sierra Club argues that I&M incurred net losses relative to market energy prices of $25.1 million in 2020 on a variable cost basis. Sierra Club presents testimony that these losses could have been mitigated with more prudent unit commitment practices. Additionally, Sierra Club argues that I&M's latest PSCR plan indicates that I&M intends to continue its uneconomic operation and commitment practices at the Rockport units. 2 Tr 332. Sierra Club posits that I&M plans to pass on the costs incurred from (1) generation fuel costs (for the portion I&M owns and leases), and (2) power purchased from AEG (for the portion it purchases under PPA), which combined, exceed market revenues over the next five years. 2 Tr 300.

As such, Sierra Club recommends that the Commission caution I&M that if the company extends its lease or enters into a new purchase agreement with current or future Rockport Unit 2 owners to continue to lease or purchase power from Rockport Unit 2 without contemporaneous Commission approval of the lease or purchase agreement decision, the Commission may disallow recovery of all or part of those costs in future proceedings. 2 Tr 336. Sierra Club also recommends the Commission indicate that it will disallow recovery in future fuel cost reconciliation dockets of the fuel portion of all net revenue losses incurred as a result of imprudent unit commitment decisions. 2 Tr 301.

In rebuttal, I&M's witness, Jason Stegall, testifies that I&M's use of energy generated from its Rockport units to satisfy Michigan customers' energy requirements is reasonable and thus, the

Commission should continue to allow the company to include these resources in its PSCR plan. 2 Tr 103. Witness Stegall also testified on cross-examination that I&M and AEG are going to acquire a 100% interest in Rockport Unit 2. 2 Tr 111. In rebuttal, I&M witness Heimberger testified that Sierra Club's calculations were flawed. Witness Heimberger testified that I&M's generating units are operated, along with the units of other PJM members, to meet the total PJM load requirements on the most economical basis, based on price offers, subject to transmission limitations. Witness Heimberger argues that this operation was simulated in the development of the generation forecast by means of the PLEXOS simulation model, a production-costing computer program that AEP uses to simulate a market-price dispatch of its generation units. *Id*. Witness Heimberger states that PLEXOS commits units in PJM based on variable energy costs (fuel and variable O&M), which is the same basis with which the PJM market-price is determined. Witness Heimberger testifies that the PLEXOS forecasting model will not dispatch or run the Rockport units uneconomically. 2 Tr 243-244. I&M argues that the company's updated analysis demonstrates the errors in Sierra Club's conclusions and recommendations. 2 Tr 246.

The Commission agrees with the Staff's assertion that I&M's decision to commit the Rockport units as must run is uneconomic and warrants additional review in the reconciliation of this plan case. The Commission finds that I&M shall document, and make available to the Staff upon request, the basis for the company's decision to designate a generating unit as must run when the company's forecast demonstrates that the decision to do so will result in marginal costs to operate the generating unit that would exceed the revenue attributed to supplying that power to the PJM market. The Commission may disallow fuel portions of all net revenue losses incurred as a result of imprudent unit commitment decisions at the Rockport units.

I&M's purchase of Rockport Unit 2 was announced just prior to the evidentiary hearing in this case, and no forecasts included the purchase in the evaluation of the PSCR plan and costs. The Commission does not believe it is necessary for the company to refile its PSCR plan as the forecast was accurate at the time the case was filed and the PSCR factor for this year is accurate. The Commission finds that I&M shall include the impact of the purchase of Rockport Unit 2 in its 2021 PSCR reconciliation proceeding.

THEREFORE, IT IS ORDERED that:

A. Indiana Michigan Power Company's application to implement a power supply cost recovery plan for the 2021 plan year is approved as amended by this order.

B. Indiana Michigan Power Company's proposed power supply cost recovery factor is approved.

C. The Commission issues a warning under MCL 460.6j(7) and the Commission's Code of Conduct, Mich Admin Code, R 460.10101 *et seq*., that Indiana Michigan Power Company may not be able to recover its full costs under the Ohio Valley Electric Corporation's Inter-Company Power Agreement nor the fuel portions of all net revenue losses incurred because of imprudent unit commitment decisions at the Rockport units unless justified as part of the annual reconciliation of its 2021 power supply cost recovery plan.

D. Indiana Michigan Power Company shall, as part of its 2021 integrated resource plan filing, provide a comprehensive review and analysis of the Inter-Company Power Agreement as described in the May 13, 2021 order in Case No. U-20529.

E. Indiana Michigan Power Company shall document, and make available to the Commission Staff upon request, the basis for the company's decision to designate a generating unit as must run

when the company's forecast demonstrates that the decision to do so will result in excess costs as described in this order.

F. Indiana Michigan Power Company shall include the impact of the purchase of Rockport Unit 2 in its 2021 power supply cost recovery reconciliation proceeding.

The Commission reserves jurisdiction and may issue further orders as necessary.

Any party desiring to appeal this order must do so in the appropriate court within 30 days after issuance and notice of this order, pursuant to MCL 462.26. To comply with the Michigan Rules of Court's requirement to notify the Commission of an appeal, appellants shall send required notices to both the Commission's Executive Secretary and to the Commission's Legal Counsel. Electronic notifications should be sent to the Executive Secretary at mpscedockets@michigan.gov and to the Michigan Department of the Attorney General - Public Service Division at pungp1@michigan.gov. In lieu of electronic submissions, paper copies of such notifications may be sent to the Executive Secretary and the Attorney General - Public Service Division at 7109 W. Saginaw Hwy., Lansing, MI 48917.

MICHIGAN PUBLIC SERVICE COMMISSION

Daniel C. Scripps, Chair

Tremaine L. Phillips, Commissioner

Katherine L. Peretick, Commissioner

By its action of November 18, 2021.

Lisa Felice, Executive Secretary

P R O O F O F S E R V I C E

STATE OF MICHIGAN)

Case No. U-20804

County of Ingham)

Brianna Brown being duly sworn, deposes and says that on November 18, 2021 A.D. she electronically notified the attached list of this **Commission Order via e-mail transmission**, to the persons as shown on the attached service list (Listserv Distribution List).

Brianna Brown

Subscribed and sworn to before me
this 18th day of November 2021.

Angela P. Sanderson
Notary Public, Shiawassee County, Michigan
As acting in Eaton County
My Commission Expires: May 21, 2024

Service List for Case: U-20804

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JIF-3 00001

PAUL CHODAK III

Executive Vice President – Generation

Paul Chodak is executive vice president – Generation. He is responsible for the management of AEP's nuclear, fossil, hydro and wind generating units, and Ohio Valley Electric Corp./Indiana-Kentucky Electric Corporation's (OVEC/IKEC) generating assets. This includes engineering, construction and operation of generating units, and activities related to fuel procurement and emission monitoring and logistics. The Cook Nuclear, Engineering, the Projects & Field Services, Fossil & Hydro Generation, Environmental Services, regulated Commercial Operations and regulated Generation Development groups report to him.

Previously, Chodak was executive vice president- Utilities, overseeing the activities of all AEP's utility operating companies. In this role, he was responsible for the growth of AEP's regulated utility operations as they focused on and invested in advanced technologies to deliver more reliable, affordable and cleaner energy to customers.

From 2008-2016, Chodak successfully led AEP's Southwestern Electric Power and then Indiana and Michigan Power companies as their president and chief operating officer. In both positions, he was responsible for company operations and financial performance, as well as a wide range of external relationships.

Chodak began his career with AEP in 2001 as a senior project manager. In 2002, he was named director of regional engineering for regulated generation, working with a team that provided engineering support for power plants. He was named managing director, corporate technology development in 2003, and led a team that evaluated existing pollution control technologies and recommended solutions to meet environmental compliance requirements.

In 2004, Chodak led efforts to implement AEP's environmental compliance plan as director, environmental programs and was responsible for more than $2 billion of capital investments. He was part of the team responsible for the successful completion of the Mountaineer Plant flue gas desulfurization retrofit project.

In early 2007, Chodak was named director, new generation, responsible for the installation of several natural gas fueled power plants, both simple- and combined-cycle plants, as well as AEP's integrated gasification combined cycle (IGCC) program. He was part of the team that successfully commissioned the first two units at AEP's Harry D. Mattison Power Plant in northwest Arkansas, as well as the Stall Plant in Shreveport, La.

Prior to joining AEP, Chodak was a staff scientist at Los Alamos National Laboratory conducting research on technology and policy issues concerning nuclear power and proliferation risks. Chodak served more than seven years in the U.S. Navy as a submarine officer, earning numerous commendations and completing both submarine and chief engineer officer qualifications.

He earned a doctorate degree in nuclear engineering from Massachusetts Institute of Technology in 1996 and completed MIT's Reactor Technology Course for Utilities Executives in 2011. He holds a master's degree in civil engineering from Virginia Polytechnic Institute and State University, and a bachelor of science degree in chemical engineering with honors from Worcester Polytechnic Institute. Chodak graduated from the Harvard Business School Advanced Management Program in 2015.

Chodak serves on the Board for the Columbus Regional Airport Authority and is a Capital University Trustee. He is also a Habitat for Humanity Champion. At AEP, he is an executive sponsor of the Military Veteran Employee Resource Group (MVERG).

B2B & SUPPLIERS

RECREATION

ENVIRONMENT

SAFETY & HEALTH

JIF-3 00002

JIF-5: Public Discovery Responses and Attachments

Name	File Type
LEI-DR-1.2.9	PDF
LEI 1.6.4 Attachment 1	Excel
LEI 4.1.1	PDF
LEI 5.1.3(b)	PDF
LEI 5.1.3 Attachment 1	PDF
NRDC INT 1-06	PDF
NRDC RFA 1-07	PDF
NRDC INT 1-011(a)	PDF
OCC INT-05-004	PDF
OCC INT-06-10	PDF

OHIO POWER COMPANY'S RESPONSE TO
THE PUBLIC UTILITIES COMMISSION OF OHIO'S
AUDITOR LONDON ECONOMICS INTERNATIONAL LLC'S
PUCO CASE NO. 18-1759-EL-RDR
FIRST SET

DATA REQUEST

LEI-DR-1.2.9 Please describe OVEC's coal burn forecasting methodology, including: Description of software tools, data inputs, and data outputs used for the modeling; How far in advance forecasts are prepared, and what is the modeling horizon and granularity (i.e. annual, monthly, or weekly) of forecasts; The relationship between forecasting and procurement/RFP; How frequently are the coal burn forecasts updated; and provide OVEC's monthly coal burn forecasts performed during the audit period.

RESPONSE

The generation forecast is prepared utilizing the cost of fuel delivered, as well as other data (fuel handling, variable operations & maintenance, consumable costs, scheduled maintenance outages, and forced outage factors) to determine the projected generation for each of the Companies' units in the PJM Interconnection, LLC ("PJM") Regional Transmission Organization power market. Typically updated bi-annually, the forecast, providing monthly consumption data, could trigger the need for a Request for Proposal ("RFP") depending on inventory levels and committed purchases for the current year or future years.

Please see LEI 1.2.9 CONFIDENTIAL Attachment 1.pdf and LEI 1.2.9 CONFIDENTIAL Attachment 2.pdf for the coal consumption forecasts in 2018 and 2019.

OHIO POWER COMPANY'S RESPONSE TO
THE PUBLIC UTILITIES COMMISSION OF OHIO'S
AUDITOR LONDON ECONOMICS INTERNATIONAL LLC'S
PUCO CASE NO. 18-1759-EL-RDR
FOURTH SET

DATA REQUEST

LEI-4.1.1

Please provide the hourly energy earnings in the PJM energy market for each power plant unit for each of the 8,760 hours of a year over the audit period. (Excel format preferred).

RESPONSE

Please see LEI 4.1.1 Confidential Attachment 1.

OHIO POWER COMPANY'S RESPONSE TO
THE PUBLIC UTILITIES COMMISSION OF OHIO'S
AUDITOR LONDON ECONOMICS INTERNATIONAL LLC'S
PUCO CASE NO. 18-1759-EL-RDR
FIFTH SET

DATA REQUEST

LEI-5.1.3 Please explain in detail AEP Ohio/OVEC's processes of offering into the PJM markets:
a. Is there a daily meeting to discuss the assumptions used to prepare PJM market offers? For example, is there a forecast for daily generation in preparation for the resource offers in the DA market? Do the personnel in charge of offering into the PJM market receive feedback of daily data from the previous day?
b. Please elaborate on AEP Ohio/OVEC's strategy for self-committing the two coal plants. Is it based on the economic minimum operating level over a period of several days (how many days?). Does it at least to cover the operational costs? Under what circumstances apart from outages are the plants not offered into the PJM market?

RESPONSE

a. OVEC's Energy Scheduling department has an internal daily call every non-holiday weekday morning to review unit status and availability, including applicable unit derates, potential unit liabilities, outage status and expected unit return-to-service dates, etc. This information is used to formulate the DA unit offers into the PJM market. In advance of the morning call, the Energy Scheduling department also receives a daily unit status report from each plant. Information in this report is updated, as appropriate, based on real-time unit operating status during the morning calls. A similar, but less formal daily meeting takes place on weekends and holidays with OVEC's system operations personnel and the contractor that provides ES functions during weekends and holidays. The DA offers are then updated, if necessary, based on conditions at that time.

OVEC became fully integrated into PJM in November 2018, at that time, no formal process was in place whereby OVEC could evaluate prior day performance data. OVEC has subsequently established an internal PJM Demand Comparison Report which is generated daily. This report provides operating data that includes a unit by unit hourly comparison of actual net generation versus PJM demand. This report is also made available to plant operations personnel to aid them in evaluating prior day unit and operations related performance. An example of this report is provided as LEI 5.1.3 Attachment 1.

b. Units are offered into the PJM market consistent with the sponsor approved Operating Committee procedures. With but one exception, units that are in service and expected to be available in the day-ahead market are offered as must run. During Ozone Season Unit 6 at Clifty Creek is assigned an opportunity cost associated with its NOx emissions profile and is offered as Economic. Given OVEC's energy costs as determined pursuant to the PJM approved fuel cost

OHIO POWER COMPANY'S RESPONSE TO
THE PUBLIC UTILITIES COMMISSION OF OHIO'S
AUDITOR LONDON ECONOMICS INTERNATIONAL LLC'S
PUCO CASE NO. 18-1759-EL-RDR
FIFTH SET

policy, units offered as must run consistently covered fuel costs during the audit period. Outside of outages, if a unit is available, OVEC offers it into the PJM market. Potential exceptions could include unusual non-market related events such as coal shortages and/or some form of force majeure event outside of OVEC's control.

PJM Demand Comparison Report
6/2/2020

UnitID	Date	Hour	PJM Net Generation	Unit Net Generation	PJM Demand	Unit Demand	PJM Demand Shortage	PJM Seasonal Net Depend Capacity
CC1	6/2/2020	01	92.60	95.00	93.00	95.40	-0.40	195.00
CC1	6/2/2020	02	92.60	95.00	93.00	95.40	-0.40	195.00
CC1	6/2/2020	03	92.40	95.00	93.00	95.60	-0.60	195.00
CC1	6/2/2020	04	93.20	96.00	93.00	95.80	0.20	195.00
CC1	6/2/2020	05	91.20	94.00	93.00	95.80	-1.80	195.00
CC1	6/2/2020	06	92.30	95.00	93.00	95.70	-0.70	195.00
CC1	6/2/2020	07	93.30	96.00	93.00	95.70	0.30	195.00
CC1	6/2/2020	08	95.60	98.00	93.00	95.40	2.60	195.00
CC1	6/2/2020	09	93.00	95.00	93.00	95.00	0.00	195.00
CC1	6/2/2020	10	92.50	94.00	93.00	94.50	-0.50	195.00
CC1	6/2/2020	11	95.60	97.00	94.00	95.40	1.60	195.00
CC1	6/2/2020	12	110.50	112.00	114.00	115.50	-3.50	195.00
CC1	6/2/2020	13	163.20	165.00	162.00	163.80	1.20	195.00
CC1	6/2/2020	14	191.80	194.00	185.00	187.20	6.80	195.00
CC1	6/2/2020	15	198.70	201.00	195.00	197.30	3.70	195.00
CC1	6/2/2020	16	192.80	195.00	188.00	190.20	4.80	195.00
CC1	6/2/2020	17	196.80	199.00	192.00	194.20	4.80	195.00
CC1	6/2/2020	18	199.80	202.00	198.00	200.20	1.80	195.00
CC1	6/2/2020	19	196.60	199.00	197.00	199.40	-0.40	195.00
CC1	6/2/2020	20	156.00	158.00	145.00	147.00	11.00	195.00
CC1	6/2/2020	21	99.10	101.00	97.00	98.90	2.10	195.00
CC1	6/2/2020	22	92.90	95.00	95.00	97.10	-2.10	195.00
CC1	6/2/2020	23	92.80	95.00	93.00	95.20	-0.20	195.00
CC1	6/2/2020	24	93.70	96.00	93.00	95.30	0.70	195.00

PJM Net Generation - unit net generation at the unit bus less allocated FGD auxiliary power.
PJM Demand - Demand signal sent by PJM to OVEC-IKEC System Operations.
Unit Demand - PJM demand signal as seen by Ovation. This excludes the allocated FGD auxiliary power.
PJM Demand Shortage - PJM net generation minus PJM Demand. A negative number indicates a shortage.
Seasonal Dependable Net Generation - net dependable unit capability less estimated allocated FGD auxiliiary power as reportec to PJM.

JE-5-00007

PJM Demand Comparison Report
6/2/2020

UnitID	Date	Hour	PJM Net Generation	Unit Net Generation	PJM Demand	Unit Demand	PJM Demand Shortage	PJM Seasonal Net Depend Capacity
CC2	6/2/2020	01	94.60	97.00	93.00	95.40	1.60	196.00
CC2	6/2/2020	02	92.60	95.00	93.00	95.40	-0.40	196.00
CC2	6/2/2020	03	91.40	94.00	93.00	95.60	-1.60	196.00
CC2	6/2/2020	04	93.20	96.00	93.00	95.80	0.20	196.00
CC2	6/2/2020	05	94.20	97.00	93.00	95.80	1.20	196.00
CC2	6/2/2020	06	92.30	95.00	93.00	95.70	-0.70	196.00
CC2	6/2/2020	07	94.30	97.00	93.00	95.70	1.30	196.00
CC2	6/2/2020	08	93.60	96.00	93.00	95.40	0.60	196.00
CC2	6/2/2020	09	95.00	97.00	93.00	95.00	2.00	196.00
CC2	6/2/2020	10	93.50	95.00	93.00	94.50	0.50	196.00
CC2	6/2/2020	11	94.60	96.00	96.00	97.40	-1.40	196.00
CC2	6/2/2020	12	124.50	126.00	128.00	129.50	-3.50	196.00
CC2	6/2/2020	13	186.20	188.00	183.00	184.80	3.20	196.00
CC2	6/2/2020	14	195.80	198.00	192.00	194.20	3.80	196.00
CC2	6/2/2020	15	197.70	200.00	195.00	197.30	2.70	196.00
CC2	6/2/2020	16	197.80	200.00	192.00	194.20	5.80	196.00
CC2	6/2/2020	17	191.80	194.00	191.00	193.20	0.80	196.00
CC2	6/2/2020	18	198.80	201.00	198.00	200.20	0.80	196.00
CC2	6/2/2020	19	198.60	201.00	198.00	200.40	0.60	196.00
CC2	6/2/2020	20	158.00	160.00	147.00	149.00	11.00	196.00
CC2	6/2/2020	21	104.10	106.00	99.00	100.90	5.10	196.00
CC2	6/2/2020	22	92.90	95.00	95.00	97.10	-2.10	196.00
CC2	6/2/2020	23	92.80	95.00	93.00	95.20	-0.20	196.00
CC2	6/2/2020	24	93.70	96.00	93.00	95.30	0.70	196.00

PJM Net Generation - unit net generation at the unit bus less allocated FGD auxiliary power.
PJM Demand - Demand signal sent by PJM to OVEC-IKEC System Operations.
Unit Demand - PJM demand signal as seen by Ovation. This excludes the allocated FGD auxiliary power.
PJM Demand Shortage - PJM net generation minus PJM Demand. A negative number indicates a shortage.
Seasonal Dependable Net Generation - net dependable unit capability less estimated allocated FGD auxiliiary power as reportec to PJM.

PJM Demand Comparison Report
6/2/2020

UnitID	Date	Hour	PJM Net Generation	Unit Net Generation	PJM Demand	Unit Demand	PJM Demand Shortage	PJM Seasonal Net Depend Capacity
CC3	6/2/2020	01	93.60	96.00	93.00	95.40	0.60	196.00
CC3	6/2/2020	02	92.60	95.00	93.00	95.40	-0.40	196.00
CC3	6/2/2020	03	91.40	94.00	93.00	95.60	-1.60	196.00
CC3	6/2/2020	04	93.20	96.00	93.00	95.80	0.20	196.00
CC3	6/2/2020	05	92.20	95.00	93.00	95.80	-0.80	196.00
CC3	6/2/2020	06	93.30	96.00	93.00	95.70	0.30	196.00
CC3	6/2/2020	07	91.30	94.00	93.00	95.70	-1.70	196.00
CC3	6/2/2020	08	91.60	94.00	93.00	95.40	-1.40	196.00
CC3	6/2/2020	09	94.00	96.00	93.00	95.00	1.00	196.00
CC3	6/2/2020	10	93.50	95.00	93.00	94.50	0.50	196.00
CC3	6/2/2020	11	93.60	95.00	93.00	94.40	0.60	196.00
CC3	6/2/2020	12	102.50	104.00	109.00	110.50	-6.50	196.00
CC3	6/2/2020	13	144.20	146.00	145.00	146.80	-0.80	196.00
CC3	6/2/2020	14	163.80	166.00	158.00	160.20	5.80	196.00
CC3	6/2/2020	15	167.70	170.00	165.00	167.30	2.70	196.00
CC3	6/2/2020	16	168.80	171.00	161.00	163.20	7.80	196.00
CC3	6/2/2020	17	163.80	166.00	163.00	165.20	0.80	196.00
CC3	6/2/2020	18	168.80	171.00	168.00	170.20	0.80	196.00
CC3	6/2/2020	19	168.60	171.00	167.00	169.40	1.60	196.00
CC3	6/2/2020	20	137.00	139.00	127.00	129.00	10.00	196.00
CC3	6/2/2020	21	93.10	95.00	93.00	94.90	0.10	196.00
CC3	6/2/2020	22	93.90	96.00	93.00	95.10	0.90	196.00
CC3	6/2/2020	23	91.80	94.00	93.00	95.20	-1.20	196.00
CC3	6/2/2020	24	92.70	95.00	93.00	95.30	-0.30	196.00

PJM Net Generation - unit net generation at the unit bus less allocated FGD auxiliary power.
PJM Demand - Demand signal sent by PJM to OVEC-IKEC System Operations.
Unit Demand - PJM demand signal as seen by Ovation. This excludes the allocated FGD auxiliary power.
PJM Demand Shortage - PJM net generation minus PJM Demand. A negative number indicates a shortage.
Seasonal Dependable Net Generation - net dependable unit capability less estimated allocated FGD auxiliiary power as reportec to PJM.

PJM Demand Comparison Report
6/2/2020

UnitID	Date	Hour	PJM Net Generation	Unit Net Generation	PJM Demand	Unit Demand	PJM Demand Shortage	PJM Seasonal Net Depend Capacity
CC4	6/2/2020	01	-6.40	-4.00	0.00	2.40	0.00	196.00
CC4	6/2/2020	02	-6.40	-4.00	0.00	2.40	0.00	196.00
CC4	6/2/2020	03	-8.60	-6.00	0.00	2.60	0.00	196.00
CC4	6/2/2020	04	-9.80	-7.00	0.00	2.80	0.00	196.00
CC4	6/2/2020	05	-7.80	-5.00	0.00	2.80	0.00	196.00
CC4	6/2/2020	06	-7.70	-5.00	0.00	2.70	0.00	196.00
CC4	6/2/2020	07	-7.70	-5.00	0.00	2.70	0.00	196.00
CC4	6/2/2020	08	-6.40	-4.00	0.00	2.40	0.00	196.00
CC4	6/2/2020	09	-6.00	-4.00	0.00	2.00	0.00	196.00
CC4	6/2/2020	10	-2.50	-1.00	0.00	1.50	0.00	196.00
CC4	6/2/2020	11	-2.40	-1.00	0.00	1.40	0.00	196.00
CC4	6/2/2020	12	-3.50	-2.00	0.00	1.50	0.00	196.00
CC4	6/2/2020	13	-3.80	-2.00	0.00	1.80	0.00	196.00
CC4	6/2/2020	14	-4.20	-2.00	0.00	2.20	0.00	196.00
CC4	6/2/2020	15	-3.30	-1.00	0.00	2.30	0.00	196.00
CC4	6/2/2020	16	-4.20	-2.00	0.00	2.20	0.00	196.00
CC4	6/2/2020	17	-3.20	-1.00	0.00	2.20	0.00	196.00
CC4	6/2/2020	18	-5.20	-3.00	0.00	2.20	0.00	196.00
CC4	6/2/2020	19	-3.40	-1.00	0.00	2.40	0.00	196.00
CC4	6/2/2020	20	-4.00	-2.00	0.00	2.00	0.00	196.00
CC4	6/2/2020	21	-3.90	-2.00	0.00	1.90	0.00	196.00
CC4	6/2/2020	22	-3.10	-1.00	0.00	2.10	0.00	196.00
CC4	6/2/2020	23	-5.20	-3.00	0.00	2.20	0.00	196.00
CC4	6/2/2020	24	-6.30	-4.00	0.00	2.30	0.00	196.00

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PJM Demand Shortage - PJM net generation minus PJM Demand. A negative number indicates a shortage.
Seasonal Dependable Net Generation - net dependable unit capability less estimated allocated FGD auxiliiary power as reportec to PJM.

PJM Demand Comparison Report
6/2/2020

UnitID	Date	Hour	PJM Net Generation	Unit Net Generation	PJM Demand	Unit Demand	PJM Demand Shortage	PJM Seasonal Net Depend Capacity
CC5	6/2/2020	01	-3.40	-1.00	0.00	2.40	0.00	196.00
CC5	6/2/2020	02	-2.40	0.00	0.00	2.40	0.00	196.00
CC5	6/2/2020	03	-3.60	-1.00	0.00	2.60	0.00	196.00
CC5	6/2/2020	04	-3.80	-1.00	0.00	2.80	0.00	196.00
CC5	6/2/2020	05	-4.80	-2.00	0.00	2.80	0.00	196.00
CC5	6/2/2020	06	-2.70	0.00	0.00	2.70	0.00	196.00
CC5	6/2/2020	07	-3.70	-1.00	0.00	2.70	0.00	196.00
CC5	6/2/2020	08	-3.40	-1.00	0.00	2.40	0.00	196.00
CC5	6/2/2020	09	-3.00	-1.00	0.00	2.00	0.00	196.00
CC5	6/2/2020	10	-2.50	-1.00	0.00	1.50	0.00	196.00
CC5	6/2/2020	11	-3.40	-2.00	0.00	1.40	0.00	196.00
CC5	6/2/2020	12	-1.50	0.00	0.00	1.50	0.00	196.00
CC5	6/2/2020	13	-2.80	-1.00	0.00	1.80	0.00	196.00
CC5	6/2/2020	14	-2.20	0.00	0.00	2.20	0.00	196.00
CC5	6/2/2020	15	-5.30	-3.00	0.00	2.30	0.00	196.00
CC5	6/2/2020	16	-2.20	0.00	0.00	2.20	0.00	196.00
CC5	6/2/2020	17	-3.20	-1.00	0.00	2.20	0.00	196.00
CC5	6/2/2020	18	-2.20	0.00	0.00	2.20	0.00	196.00
CC5	6/2/2020	19	-5.40	-3.00	0.00	2.40	0.00	196.00
CC5	6/2/2020	20	-4.00	-2.00	0.00	2.00	0.00	196.00
CC5	6/2/2020	21	-4.90	-3.00	0.00	1.90	0.00	196.00
CC5	6/2/2020	22	-4.10	-2.00	0.00	2.10	0.00	196.00
CC5	6/2/2020	23	-3.20	-1.00	0.00	2.20	0.00	196.00
CC5	6/2/2020	24	-3.30	-1.00	0.00	2.30	0.00	196.00

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PJM Demand Shortage - PJM net generation minus PJM Demand. A negative number indicates a shortage.
Seasonal Dependable Net Generation - net dependable unit capability less estimated allocated FGD auxiliiary power as reportec to PJM.

PJM Demand Comparison Report
6/2/2020

UnitID	Date	Hour	PJM Net Generation	Unit Net Generation	PJM Demand	Unit Demand	PJM Demand Shortage	PJM Seasonal Net Depend Capacity
CC6	6/2/2020	01	-4.40	-2.00	0.00	2.40	0.00	196.00
CC6	6/2/2020	02	-4.40	-2.00	0.00	2.40	0.00	196.00
CC6	6/2/2020	03	-5.60	-3.00	0.00	2.60	0.00	196.00
CC6	6/2/2020	04	-5.80	-3.00	0.00	2.80	0.00	196.00
CC6	6/2/2020	05	-5.80	-3.00	0.00	2.80	0.00	196.00
CC6	6/2/2020	06	-4.70	-2.00	0.00	2.70	0.00	196.00
CC6	6/2/2020	07	-5.70	-3.00	0.00	2.70	0.00	196.00
CC6	6/2/2020	08	-4.40	-2.00	0.00	2.40	0.00	196.00
CC6	6/2/2020	09	-4.00	-2.00	0.00	2.00	0.00	196.00
CC6	6/2/2020	10	-2.50	-1.00	0.00	1.50	0.00	196.00
CC6	6/2/2020	11	-1.40	0.00	0.00	1.40	0.00	196.00
CC6	6/2/2020	12	-2.50	-1.00	0.00	1.50	0.00	196.00
CC6	6/2/2020	13	-1.80	0.00	0.00	1.80	0.00	196.00
CC6	6/2/2020	14	-4.20	-2.00	0.00	2.20	0.00	196.00
CC6	6/2/2020	15	-2.30	0.00	0.00	2.30	0.00	196.00
CC6	6/2/2020	16	-3.20	-1.00	0.00	2.20	0.00	196.00
CC6	6/2/2020	17	-2.20	0.00	0.00	2.20	0.00	196.00
CC6	6/2/2020	18	-3.20	-1.00	0.00	2.20	0.00	196.00
CC6	6/2/2020	19	-2.40	0.00	0.00	2.40	0.00	196.00
CC6	6/2/2020	20	-3.00	-1.00	0.00	2.00	0.00	196.00
CC6	6/2/2020	21	-3.90	-2.00	0.00	1.90	0.00	196.00
CC6	6/2/2020	22	-2.10	0.00	0.00	2.10	0.00	196.00
CC6	6/2/2020	23	-3.20	-1.00	0.00	2.20	0.00	196.00
CC6	6/2/2020	24	-2.30	0.00	0.00	2.30	0.00	196.00

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PJM Demand Shortage - PJM net generation minus PJM Demand. A negative number indicates a shortage.
Seasonal Dependable Net Generation - net dependable unit capability less estimated allocated FGD auxiliiary power as reportec to PJM.

PJM Demand Comparison Report
6/2/2020

UnitID	Date	Hour	PJM Net Generation	Unit Net Generation	PJM Demand	Unit Demand	PJM Demand Shortage	PJM Seasonal Net Depend Capacity
KC1	6/2/2020	01	78.00	82.00	80.00	83.80	-2.00	194.00
KC1	6/2/2020	02	81.00	85.00	80.00	83.70	1.00	194.00
KC1	6/2/2020	03	82.00	86.00	80.00	83.70	2.00	194.00
KC1	6/2/2020	04	82.00	86.00	80.00	83.70	2.00	194.00
KC1	6/2/2020	05	81.00	85.00	80.00	83.70	1.00	194.00
KC1	6/2/2020	06	82.00	86.00	80.00	83.90	2.00	194.00
KC1	6/2/2020	07	81.00	85.00	82.00	85.90	-1.00	194.00
KC1	6/2/2020	08	115.00	120.00	189.00	193.60	-74.00	194.00
KC1	6/2/2020	09	159.00	164.00	191.00	196.00	-32.00	194.00
KC1	6/2/2020	10	171.00	176.00	191.00	196.10	-20.00	194.00
KC1	6/2/2020	11	169.00	174.00	191.00	196.00	-22.00	194.00
KC1	6/2/2020	12	170.00	175.00	191.00	196.20	-21.00	194.00
KC1	6/2/2020	13	172.00	177.00	191.00	196.40	-19.00	194.00
KC1	6/2/2020	14	188.00	193.00	192.00	197.50	-4.00	194.00
KC1	6/2/2020	15	189.00	194.00	192.00	197.50	-3.00	194.00
KC1	6/2/2020	16	188.00	193.00	185.00	190.50	3.00	194.00
KC1	6/2/2020	17	186.00	191.00	191.00	196.30	-5.00	194.00
KC1	6/2/2020	18	189.00	194.00	192.00	197.40	-3.00	194.00
KC1	6/2/2020	19	189.00	194.00	192.00	197.40	-3.00	194.00
KC1	6/2/2020	20	182.00	187.00	171.00	176.10	11.00	194.00
KC1	6/2/2020	21	150.00	155.00	140.00	144.60	10.00	194.00
KC1	6/2/2020	22	119.00	123.00	119.00	123.20	0.00	194.00
KC1	6/2/2020	23	101.00	105.00	96.00	100.10	5.00	194.00
KC1	6/2/2020	24	78.00	82.00	80.00	84.00	-2.00	194.00

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PJM Demand Shortage - PJM net generation minus PJM Demand. A negative number indicates a shortage.
Seasonal Dependable Net Generation - net dependable unit capability less estimated allocated FGD auxiliiary power as reportec to PJM.

PJM Demand Comparison Report
6/2/2020

UnitID	Date	Hour	PJM Net Generation	Unit Net Generation	PJM Demand	Unit Demand	PJM Demand Shortage	PJM Seasonal Net Depend Capacity
KC2	6/2/2020	01	80.00	84.00	80.00	83.80	0.00	192.00
KC2	6/2/2020	02	81.00	85.00	80.00	83.70	1.00	192.00
KC2	6/2/2020	03	81.00	85.00	80.00	83.70	1.00	192.00
KC2	6/2/2020	04	81.00	85.00	80.00	83.70	1.00	192.00
KC2	6/2/2020	05	79.00	83.00	80.00	83.70	-1.00	192.00
KC2	6/2/2020	06	81.00	85.00	80.00	83.90	1.00	192.00
KC2	6/2/2020	07	83.00	87.00	82.00	85.90	1.00	192.00
KC2	6/2/2020	08	122.00	127.00	195.00	199.60	-73.00	192.00
KC2	6/2/2020	09	183.00	188.00	197.00	202.00	-14.00	192.00
KC2	6/2/2020	10	183.00	188.00	197.00	202.10	-14.00	192.00
KC2	6/2/2020	11	185.00	190.00	197.00	202.00	-12.00	192.00
KC2	6/2/2020	12	185.00	190.00	198.00	203.20	-13.00	192.00
KC2	6/2/2020	13	186.00	191.00	198.00	203.40	-12.00	192.00
KC2	6/2/2020	14	189.00	194.00	198.00	203.50	-9.00	192.00
KC2	6/2/2020	15	188.00	193.00	198.00	203.50	-10.00	192.00
KC2	6/2/2020	16	188.00	193.00	190.00	195.50	-2.00	192.00
KC2	6/2/2020	17	181.00	186.00	194.00	199.30	-13.00	192.00
KC2	6/2/2020	18	191.00	196.00	198.00	203.40	-7.00	192.00
KC2	6/2/2020	19	191.00	196.00	198.00	203.40	-7.00	192.00
KC2	6/2/2020	20	155.00	160.00	156.00	161.10	-1.00	192.00
KC2	6/2/2020	21	105.00	110.00	99.00	103.60	6.00	192.00
KC2	6/2/2020	22	80.00	84.00	87.00	91.20	-7.00	192.00
KC2	6/2/2020	23	80.00	84.00	85.00	89.10	-5.00	192.00
KC2	6/2/2020	24	79.00	83.00	80.00	84.00	-1.00	192.00

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PJM Demand Shortage - PJM net generation minus PJM Demand. A negative number indicates a shortage.
Seasonal Dependable Net Generation - net dependable unit capability less estimated allocated FGD auxiliiary power as reportec to PJM.

PJM Demand Comparison Report
6/2/2020

UnitID	Date	Hour	PJM Net Generation	Unit Net Generation	PJM Demand	Unit Demand	PJM Demand Shortage	PJM Seasonal Net Depend Capacity
KC3	6/2/2020	01	94.00	98.00	90.00	93.80	4.00	192.00
KC3	6/2/2020	02	93.00	97.00	90.00	93.70	3.00	192.00
KC3	6/2/2020	03	94.00	98.00	90.00	93.70	4.00	192.00
KC3	6/2/2020	04	96.00	100.00	90.00	93.70	6.00	192.00
KC3	6/2/2020	05	94.00	98.00	90.00	93.70	4.00	192.00
KC3	6/2/2020	06	92.00	96.00	90.00	93.90	2.00	192.00
KC3	6/2/2020	07	90.00	94.00	92.00	95.90	-2.00	192.00
KC3	6/2/2020	08	142.00	147.00	189.00	193.60	-47.00	192.00
KC3	6/2/2020	09	172.00	177.00	191.00	196.00	-19.00	192.00
KC3	6/2/2020	10	178.00	183.00	191.00	196.10	-13.00	192.00
KC3	6/2/2020	11	133.00	138.00	170.00	175.00	-37.00	192.00
KC3	6/2/2020	12	184.00	189.00	192.00	197.20	-8.00	192.00
KC3	6/2/2020	13	184.00	189.00	192.00	197.40	-8.00	192.00
KC3	6/2/2020	14	185.00	190.00	192.00	197.50	-7.00	192.00
KC3	6/2/2020	15	180.00	185.00	192.00	197.50	-12.00	192.00
KC3	6/2/2020	16	181.00	186.00	183.00	188.50	-2.00	192.00
KC3	6/2/2020	17	177.00	182.00	187.00	192.30	-10.00	192.00
KC3	6/2/2020	18	183.00	188.00	192.00	197.40	-9.00	192.00
KC3	6/2/2020	19	183.00	188.00	192.00	197.40	-9.00	192.00
KC3	6/2/2020	20	175.00	180.00	167.00	172.10	8.00	192.00
KC3	6/2/2020	21	157.00	162.00	147.00	151.60	10.00	192.00
KC3	6/2/2020	22	129.00	133.00	122.00	126.20	7.00	192.00
KC3	6/2/2020	23	102.00	106.00	102.00	106.10	0.00	192.00
KC3	6/2/2020	24	97.00	101.00	90.00	94.00	7.00	192.00

PJM Net Generation - unit net generation at the unit bus less allocated FGD auxiliary power.
PJM Demand - Demand signal sent by PJM to OVEC-IKEC System Operations.
Unit Demand - PJM demand signal as seen by Ovation. This excludes the allocated FGD auxiliary power.
PJM Demand Shortage - PJM net generation minus PJM Demand. A negative number indicates a shortage.
Seasonal Dependable Net Generation - net dependable unit capability less estimated allocated FGD auxiliiary power as reportec to PJM.

PJM Demand Comparison Report
6/2/2020

UnitID	Date	Hour	PJM Net Generation	Unit Net Generation	PJM Demand	Unit Demand	PJM Demand Shortage	PJM Seasonal Net Depend Capacity
KC4	6/2/2020	01	91.00	95.00	90.00	93.80	1.00	192.00
KC4	6/2/2020	02	89.00	93.00	90.00	93.70	-1.00	192.00
KC4	6/2/2020	03	90.00	94.00	90.00	93.70	0.00	192.00
KC4	6/2/2020	04	91.00	95.00	90.00	93.70	1.00	192.00
KC4	6/2/2020	05	92.00	96.00	90.00	93.70	2.00	192.00
KC4	6/2/2020	06	89.00	93.00	90.00	93.90	-1.00	192.00
KC4	6/2/2020	07	90.00	94.00	92.00	95.90	-2.00	192.00
KC4	6/2/2020	08	153.00	158.00	189.00	193.60	-36.00	192.00
KC4	6/2/2020	09	187.00	192.00	191.00	196.00	-4.00	192.00
KC4	6/2/2020	10	187.00	192.00	191.00	196.10	-4.00	192.00
KC4	6/2/2020	11	190.00	195.00	191.00	196.00	-1.00	192.00
KC4	6/2/2020	12	190.00	195.00	192.00	197.20	-2.00	192.00
KC4	6/2/2020	13	192.00	197.00	192.00	197.40	0.00	192.00
KC4	6/2/2020	14	192.00	197.00	192.00	197.50	0.00	192.00
KC4	6/2/2020	15	191.00	196.00	192.00	197.50	-1.00	192.00
KC4	6/2/2020	16	193.00	198.00	186.00	191.50	7.00	192.00
KC4	6/2/2020	17	189.00	194.00	191.00	196.30	-2.00	192.00
KC4	6/2/2020	18	193.00	198.00	192.00	197.40	1.00	192.00
KC4	6/2/2020	19	193.00	198.00	192.00	197.40	1.00	192.00
KC4	6/2/2020	20	188.00	193.00	174.00	179.10	14.00	192.00
KC4	6/2/2020	21	175.00	180.00	161.00	165.60	14.00	192.00
KC4	6/2/2020	22	113.00	117.00	117.00	121.20	-4.00	192.00
KC4	6/2/2020	23	90.00	94.00	94.00	98.10	-4.00	192.00
KC4	6/2/2020	24	89.00	93.00	90.00	94.00	-1.00	192.00

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Seasonal Dependable Net Generation - net dependable unit capability less estimated allocated FGD auxiliiary power as reportec to PJM.

JE-5-00016

PJM Demand Comparison Report
6/2/2020

UnitID	Date	Hour	PJM Net Generation	Unit Net Generation	PJM Demand	Unit Demand	PJM Demand Shortage	PJM Seasonal Net Depend Capacity
KC5	6/2/2020	01	91.00	95.00	90.00	93.80	1.00	192.00
KC5	6/2/2020	02	91.00	95.00	90.00	93.70	1.00	192.00
KC5	6/2/2020	03	90.00	94.00	90.00	93.70	0.00	192.00
KC5	6/2/2020	04	90.00	94.00	90.00	93.70	0.00	192.00
KC5	6/2/2020	05	90.00	94.00	90.00	93.70	0.00	192.00
KC5	6/2/2020	06	89.00	93.00	90.00	93.90	-1.00	192.00
KC5	6/2/2020	07	91.00	95.00	92.00	95.90	-1.00	192.00
KC5	6/2/2020	08	123.00	128.00	189.00	193.60	-66.00	192.00
KC5	6/2/2020	09	172.00	177.00	191.00	196.00	-19.00	192.00
KC5	6/2/2020	10	179.00	184.00	191.00	196.10	-12.00	192.00
KC5	6/2/2020	11	180.00	185.00	191.00	196.00	-11.00	192.00
KC5	6/2/2020	12	182.00	187.00	192.00	197.20	-10.00	192.00
KC5	6/2/2020	13	182.00	187.00	192.00	197.40	-10.00	192.00
KC5	6/2/2020	14	182.00	187.00	192.00	197.50	-10.00	192.00
KC5	6/2/2020	15	185.00	190.00	192.00	197.50	-7.00	192.00
KC5	6/2/2020	16	189.00	194.00	185.00	190.50	4.00	192.00
KC5	6/2/2020	17	181.00	186.00	190.00	195.30	-9.00	192.00
KC5	6/2/2020	18	189.00	194.00	192.00	197.40	-3.00	192.00
KC5	6/2/2020	19	188.00	193.00	192.00	197.40	-4.00	192.00
KC5	6/2/2020	20	154.00	159.00	154.00	159.10	0.00	192.00
KC5	6/2/2020	21	105.00	110.00	101.00	105.60	4.00	192.00
KC5	6/2/2020	22	95.00	99.00	98.00	102.20	-3.00	192.00
KC5	6/2/2020	23	95.00	99.00	94.00	98.10	1.00	192.00
KC5	6/2/2020	24	89.00	93.00	90.00	94.00	-1.00	192.00

PJM Net Generation - unit net generation at the unit bus less allocated FGD auxiliary power.
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Seasonal Dependable Net Generation - net dependable unit capability less estimated allocated FGD auxiliiary power as reportec to PJM.

OHIO POWER COMPANY'S RESPONSE TO
THE PUBLIC UTILITIES COMMISSION OF OHIO'S
THE NATURAL RESOURCES DEFENSE COUNSEL
PUCO CASE NO. 18-1759-EL-RDR
SET 1

INTERROGATORY

INT 1-06 Please answer the following questions regarding the Operating Procedures Pursuant to Section 9.05 of the Amended and Restated Inter-Company Power Agreement found in LEI_13.1.1_Confidential Attachment_1 ("Operating Procedures").

a. Identify all revisions to the Operating Procedures document that were adopted on October 7, 2019.
b. Did AEP Ohio or its representative contribute to the drafting of the OVEC Operating Procedures.
c. Did Ohio Power or its representative contribute to the drafting of the OVEC Operating Procedures?
d. Did Columbus Southern Power or its representative contribute to the drafting of the OVEC Operating Procedures?
e. If the answer to the three prior questions is 'no," provide a description of how these procedures were drafted.

RESPONSE

a. Section E.1.e. was added to define how OVEC would manage unit offers into the PJM market in the event of coal inventory stockpile shortages due to contractual or fuel delivery issues.
b.-d. OVEC personnel generally draft procedure revisions/edits, and the Operating Committee members review, provide comment, and vote on the procedures and associated changes.
e. See above.

OHIO POWER COMPANY'S RESPONSE TO
THE PUBLIC UTILITIES COMMISSION OF OHIO'S
THE NATURAL RESOURCES DEFENSE COUNSEL
PUCO CASE NO. 18-1759-EL-RDR
SET 1

INTERROGATORY

RFA 1-07 Refer to the Response to Data Request LEI 1.2.9, where it is stated, "generation forecast is prepared utilizing the cost of fuel delivered, as well as other data (fuel handling, variable operations & maintenance, consumable costs, scheduled maintenance outages, and forced outage factors) to determine the projected generation for each of the Companies' units in the PJM Interconnection, LLC ("PJM") Regional Transmission Organization power market." Admit or deny that the generation forecast for the OVEC units utilizes the cost of fuel delivered and variable operations & maintenance costs.

RESPONSE

AEP Ohio's knowledge is that OVEC utilizes several factors including prior year utilization included fuel cost delivered and variable operation & maintenance costs as states in LEI 1.2.9.

OHIO POWER COMPANY'S RESPONSE TO
THE PUBLIC UTILITIES COMMISSION OF OHIO'S
THE NATURAL RESOURCES DEFENSE COUNSEL
PUCO CASE NO. 18-1759-EL-RDR
SET 1

INTERROGATORY

INT 1-011 The reply to LEI 5.1.3(b) states that "With but one exception, units that are in service and expected to be available in the day-ahead market are offered as must run." Please answer the following questions regarding that statement:

a. For each OVEC unit (including Clifty Creek Unit 6) and each day of the audit period, identify if the unit was offered in a commitment status of "must run", "economic", or on outage. If other status were offered, use and define the commitment status markers as used by OVEC
b. Provide the monthly or annual "opportunity cost associated with [Clifty Creek Unit 6's] NOx emissions profile" as applied during the audit period.

RESPONSE

a. Units are offered as described in LEI 5.1.3(b) consistent with the Operating Committee procedures. Please see NRDC 1-009 for instances where OVEC used a commitment status other than "Economic" for Clifty Creek No. 6. Please see LEI 2.5.1 for a list of outages during the audit period.
b. AEP Ohio does not possess this information. Please see LEI 1.1.3.

OHIO POWER COMPANY'S RESPONSE TO
THE OFFICE OF THE OHIO CONSUMERS' COUNSEL'S
DISCOVERY REQUEST
PUCO CASE 18-1759-EL-RDR
FIFTH SET

INTERROGATORY

INT-05-004 Regarding the development of the hourly energy market generator commitment offers, (including decisions on whether to self-schedule, self-schedule at the minimum operating level and dispatch economically above, or dispatch economically) during calendar years 2018 and 2019:

a. Indicate which production costs are considered variable on a short-term basis for the purposes of deciding generator commitment offer status at the OVEC units (e.g., fuel costs, variable operations and maintenance costs, emissions costs, effluent costs, etc.).

b. Indicate what production cost are considered fixed on short-term basis for the purposes of deciding generator commitment offer status at the OVEC units (e.g., fuel costs, variable operations and maintenance costs, emissions costs, effluent costs, etc.).

c. Indicate if any costs are considered variable for the purposes of committing a unit (i.e., self-scheduling or economically dispatching a unit at its minimum operating level) but not for the purpose of dispatching it above the minimum operating level.

d. Identify if there are any fuel costs that are considered fixed for the purposes of commitment, dispatch, or both. Provide a detailed explanation of how the fixed component is determined and provide a workpaper demonstrating the fixed and variable breakdown.

e. Please explain how unit start up and shut down times and costs are incorporated into the unit commitment and dispatch decision-making.

RESPONSE

a-e.) Please see the OVEC Fuel Cost Policy in INT-05-003 Confidential Attachments 1 and 2.

OHIO POWER COMPANY'S RESPONSE TO
THE OFFICE OF THE OHIO CONSUMERS' COUNSEL'S
DISCOVERY REQUEST
PUCO CASE 18-1759-EL-RDR
SIXTH SET

INTERROGATORY

INT-6-10 Regarding the Company's role in any operational or planning decisions made by OVEC that impact the cost of power sold to customer.

a. State the Company's role and responsibility in the decision-making process;

b. Indicate whether the Company had any input or vote over any operational or planning decisions made by OVEC;

c. State the Company's role and responsibility in the decision-making process;

d. Indicate whether the Company has any input or vote over any operational or planning decision made by OVEC; and

e. Indicate whether the OVEC Operating Committee decisions must be decided by a simple majority vote or, if not, what percentage of the members' votes are needed to reach a decision.

RESPONSE

The Company objects to the form of the question as this request is vague, overbroad and/or unduly burdensome. Without waiving the foregoing objections or any general objection the Company may have, the Company states the following:

a. Decisions with respect to OVEC's operations are made by OVEC's management, with oversight and approval of annual capital expense budgets by OVEC's Board of Directors. The Company currently has one representative to OVEC's 15-member Board of Directors. Certain decisions, including with respect to procedures for scheduling delivery of available energy, and recommendations as to scheduling, operating, testing and maintenance procedures and other related matters, are delegated to the "Operating Committee" pursuant to Section 9.05 of the Amended and Restated Inter-Company Power Agreement among OVEC, the Company and the other parties thereto, with any such procedures codified in the "Operating Procedures" of the such Operating Committee. AEP's subsidiaries are collectively entitled to one member of the Operating Committee.

b-d. See response to subpart a. above.

e. Pursuant to Section 9.05 of the Amended and Restated Inter-Company Power Agreement among OVEC, the Company and the other parties thereto, "[t]he decisions of the Operating Committee, including the adoption or modification of any procedure by the Operating Committee pursuant to this Section 9.04, must receive the affirmative vote of at least two-thirds of the members of the Operating Committee present at any meeting." Currently, there are 10 members of the Operating Committee, including OVEC's representative. In addition, pursuant to procedures codified in in Part E.1 of the "Operating Procedures" of the such Operating Committee, the unanimous approval of the Operating Committee (excluding OVEC's representative) is required to change the commitment status of "Must Run" with respect to the

OHIO POWER COMPANY'S RESPONSE TO
THE OFFICE OF THE OHIO CONSUMERS' COUNSEL'S
DISCOVERY REQUEST
PUCO CASE 18-1759-EL-RDR
SIXTH SET

offer of the "PJM Sponsors' aggregate share of reserved Available Energy into PJM's Day-Ahead Energy Market," with limited exceptions expressly set forth therein, including with respect to Clifty Unit No. 6 during ozone season.

24th Annual Ohio

Energy Management

CONFERENCE

Workshop P

Affordable Resiliency – Best Practices & Case Studies in Integrating Backup Generation with Electricity Supply to Minimize Total Cost of Ownership

Tuesday, February 18, 2020
3:15 p.m. to 4:30 p.m.

Biographical Information

Joe Glanzman, Director of Business Development
AEP OnSite Partners
303 Marconi Blvd, Columbus, OH 43215
614-583-3923 jaglanzman@aepes.com

Joe began his career with American Electric Power (AEP) as a mechanical engineer in the Resource Planning organization, and has served in several positions of increasing responsibility in AEP's Finance, Regulatory Services, Engineering Services and Project Management organizations. Joe spent the majority of his career within the integrated utility supporting major generation projects, including capital project screening and business case development, engineering and design, planning and scheduling, construction, commissioning and regulatory approval.

Joe joined AEP OnSite Partners in 2017 as the Director of Business Development, where he works directly with customers to deliver energy solutions based upon market knowledge, innovative application of technology and deal-structuring capabilities. AEP OnSite Partners targets opportunities in distributed solar, energy storage, peaking generation, combined heat and power, and other energy solutions that create value for our customers. Joe is married with three kids and lives in Pickerington, Ohio.

Joe holds a BS of Mechanical Engineering from the University of Dayton, an MS of Mechanical Engineering from the Georgia Institute of Technology, and an MBA with a concentration in Finance from The Ohio State University. Joe is a registered Professional Engineer and Project Management Professional.

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AF1

AEP ONSITE PARTNERS™
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Affordable Resiliency

Integrating Backup Generation with Electricity Supply to Minimize Total Cost of Ownership

24th Annual Ohio Energy Management Conference
February 18th, 2020



AEP OnSite Partners offer energy asset services nationwide.

BOUNDLESS ENERGY℠

Slide 2

AF1 Change to 24th not 24nd
Ann Ford, 1/20/2020

AEP ONSITE PARTNERS
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- **Overview**
- **Revenues**
- **Costs**
- **Valuation Techniques**
  - DCF
  - Monte Carlo Simulation
- **Case Study**

AEP ONSITE PARTNERS
An AEP Company

Presentation Preview

- Backup Generation can be costly
- Backup Generation can provide substantial benefits
- Must minimize Costs and maximize Benefits before making project investment decisions

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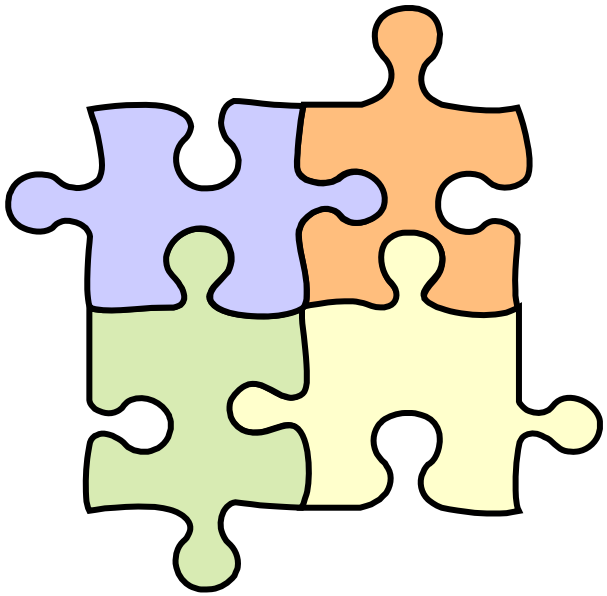
An AEP Company

Generation Value Streams

Resilience / Backup
Ancillary Services Market
Energy Savings
Distribution Savings
Capacity Peak Shaving (Demand Response & PLC)
Transmission Peak Shaving (NSPL)



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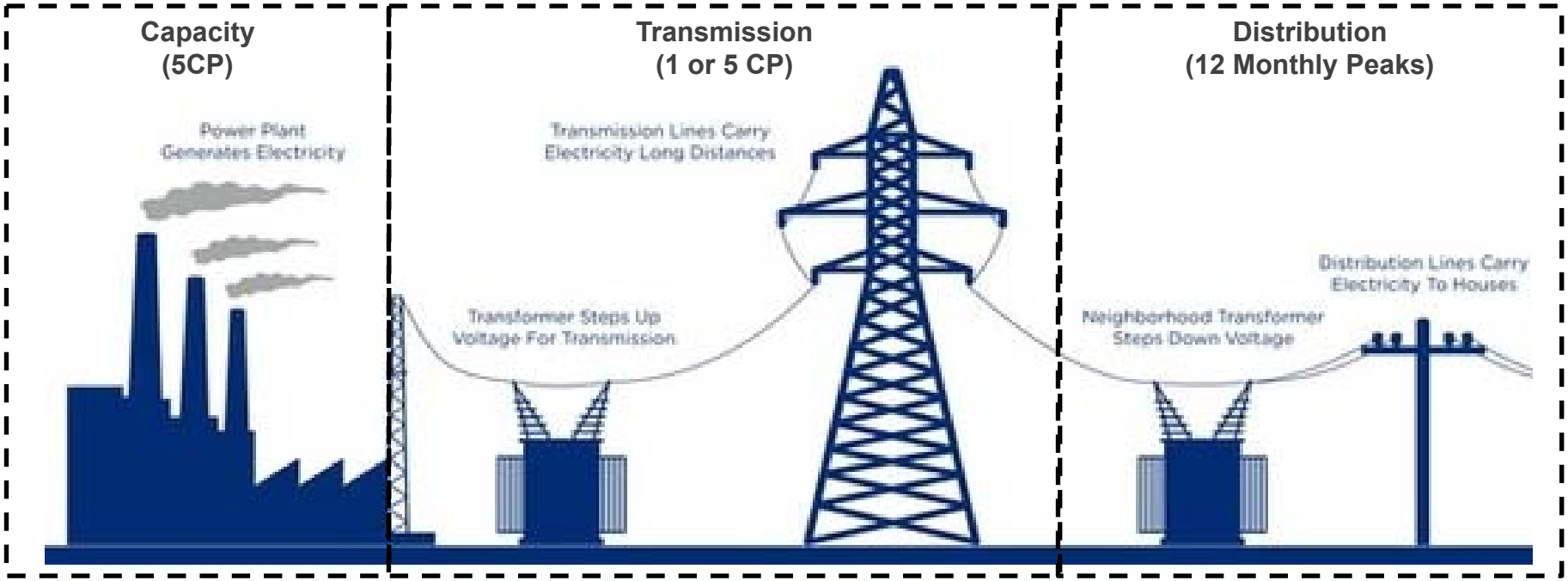
Why are Trans and Cap so valuable?

Utilities recover the entire fixed cost of power plants and transmission grid investments during the annual peak usage hours (either 5CP or 1CP)



Key Takeaway: Properly dispatched peaking generation reduces the amount of power taken from the grid during these peak hours of the year, eliminating ~30-40% of a typical customer's bill.

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Transmission Peak Shaving

State	Utility	Transmission (NSPL) Calculation Method
IL	ComEd	5CP
OH	AEPOH	1CP
	Dayton	1CP
	Duke	1CP
	Cleveland Ill - FE	5CP
	Ohio Ed - FE	5CP
	Toledo Ed - FE	5CP
PA	Duquesne	1CP
	MetEd/Penelec - FE	5CP
	West Penn - FE	5CP
	Penn Power - FE	5CP
	PECO	5CP
	PPL	1CP

- Network Transmission Service Peak Load Contribution (NSPL)
- Annual Transmission rates are set during the RTO's previous year's peak load hours
- Calculated using either 5 Coincident Peak (5CP) or 1 Coincident Peak (1CP)

Key Takeaway: Running behind-the-meter generation during the peak load hours reduces the customer's transmission rates in the following year.

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Capacity Peak Shaving

PLC Management / Avoidance

- Peak Load Contribution (PLC)
- Annual Capacity rates are set during the RTO's previous year's 5 peak load hours
- Running behind-the-meter generation during those peak load hours reduces the customer's capacity rates ***in the following year***.

Demand Response (DR)

- Receive compensation by running generators and/or reducing load
- Must contract with (or be) a PJM Curtailment Service Provider to participate
- Provides ***immediate*** (Year 1) revenues for Peaking Gen projects
- Allows Bundled Market Participation
- DR value goes to $0 in year 2 (when PLC savings "kick in")

pjm

Key Takeaway: Running behind-the-meter generation during the peak load hours reduces the customer's capacity rates in the following year, and creates DR revenue in year 1 of operation.

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Peaking Gen Energy Savings

- On-Site Peaking Gen provides an ***embedded energy spread option***
- How often your asset is "in the money" is determined by comparing:

Cost to Self-Produce Energy	Cost of Grid-Supplied Energy
[Unit's Heat Rate x Local Fuel Price] + Unit's Variable O&M	Local Energy Price (LMP) + Local Distribution Company Adders + Avoided Losses

- ***Intrinsic Value*** = The value/savings that can be generated by dispatching the asset against the prices observed in the forward gas and power markets
- ***Extrinsic Value*** = The value of the flexibility of this asset to respond to future changes in gas and power market prices

Key Takeaway: This is not a static analysis! Properly dispatching to maximize energy revenues requires an hour-by-hour comparison of continuously fluctuating fuel and power markets.

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Bid Development Details

The cost to run each generator is determined using the cost to operate and the cost avoidance from volumetric LDC Adders:

$$Strike\ Price = \frac{HR_{HHV}\ x\ Fuel}{Loss\ Factor} + VOM\ - LDC\ Adders$$

Natural Gas example assuming 5% Loss Factor after deration and $12/MWh VOM

$$NG\ SP = \frac{9.23\ x\ \$3.00/MMBTU}{1.05} + \frac{\$12}{MWh} - LDC\ Adders = \frac{\$\mathbf{38.37}}{\boldsymbol{MWh}} - LDC\ adders$$

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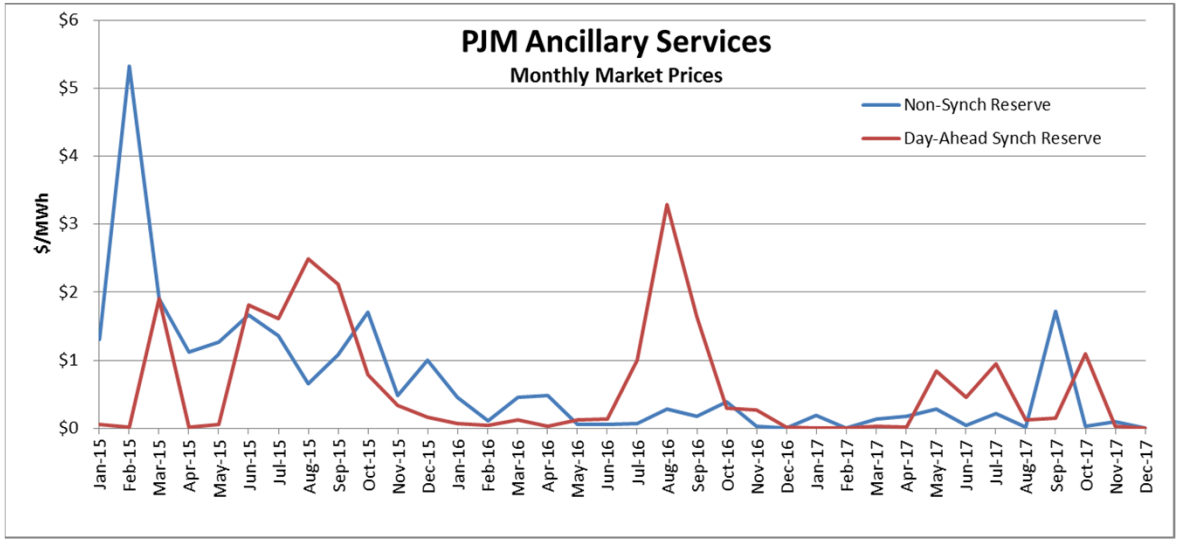
PJM Ancillary Services Market Revenues

- Another revenue stream for Peaking Generation projects
  - Synchronized Reserve
  - Non-Synchronized Reserve
  - Day-Ahead Scheduling Reserve



pjm

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Installation Cost Components

- **Capital install cost is a major driver of project valuation**
  - Costs are large and incurred up front (DCF)
- **Proper estimate must consider all of the following:**
  - Engineering & Drafting
  - Generator and Enclosures
  - Electrical / Switchgear
  - Fuel tanks and piping
  - Interconnection / Air Permitting
  - Installation Labor
  - Development Costs
  - Project Duration (until In-Service)

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O&M Cost Components

- **Ongoing costs of Operating and Maintaining equipment must be considered in project valuation**
- **Fixed O&M Costs:**
  - Insurance
  - Monthly / Annual Testing costs
  - Annual / Periodic Maintenance
- **Variable O&M Costs:**
  - Consumables
  - Run-based maintenance

Key Takeaway: Must properly identify Variable vs Fixed O&M to ensure proper dispatch signal

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Tax Costs

- Peaking Generation projects are potentially subject to Property tax, Federal tax, and Production (or kWh) tax
- Property Taxes – Vary by state, can be sizable, must account for in valuation
- Federal Tax Reform - Tax Cuts and Jobs Act of 2017

	Before Tax Reform	After Tax Reform
Federal Corporate Tax Rate	35%	21%
Accelerated Depreciation	40%	100%

- These changes improve peaking generation project economics

Key Takeaway: Project valuations can be optimized by i) fully understanding and ii) properly allocating tax ownership and/or liability

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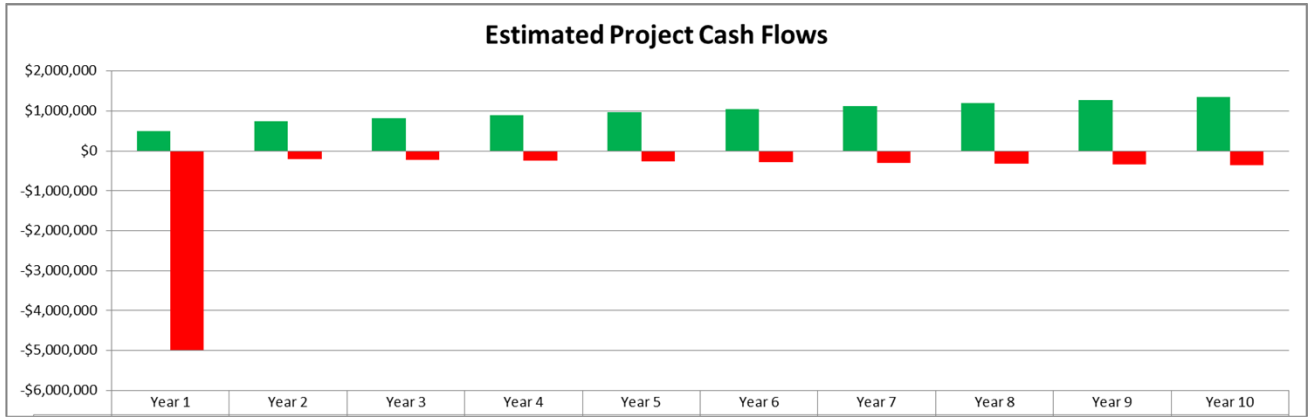
Simple Project Valuation: Discounted Cash Flow (DCF) Analysis

- Identify all applicable costs and revenues
- Estimate magnitude and timing of these cash flows
- Perform DCF analysis of the after tax cash flows
- Appropriate Discount Rate



Key Takeaway: Project Valuation varies greatly depending on how well you manage the original install cost, ongoing maintenance, and dispatch of these assets to maximize savings and market revenues.

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Sophisticated Project Valuation: Monte Carlo DCF simulation

- **Performing a single DCF analysis is insufficient**
  - Cash flow graphs intended to provide simple illustration of project costs and revenues
  - **Cannot** rely on single-point estimates to properly value project.
  - Rather, **use Monte Carlo simulation**

- **Why? Project costs and revenues are NOT discrete, fully-predictable numbers**
  - Key inputs (revenues and costs) should be modeled as probability distributions
  - Input assumptions are often correlated
  - Use DCF simulation to produce the entire distribution of valuation outcomes

- **Reality is dynamic… models need to be too!**

Key Takeaway: Monte Carlo simulation of critical DCF inputs should be employed to determine the expected distribution of project valuation outcomes.

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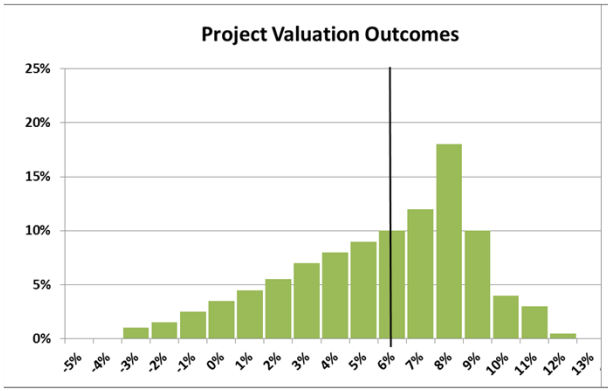
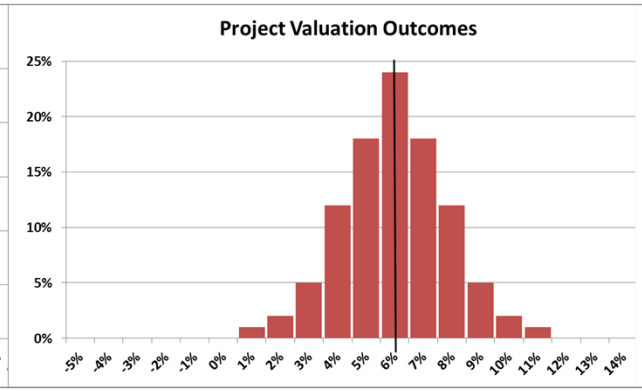
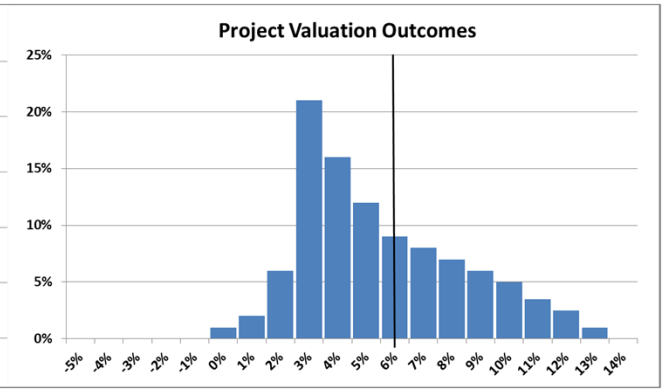
Sophisticated Project Valuation: Monte Carlo DCF simulation

- Beyond the mean… all averages are not alike!







Mean= 6%	Mean= 6%	Mean= 6%
Median= 6.5%	Median= 6.0%	Median= 4.7%
95% CI Range= -2% to 11%	95% CI Range= 2% to14%	95% CI Range= 1% to 12%
Basis Point Variance= 1,023	Basis Point Variance= 336	Basis Point Variance= 827

Key Takeaway: Demand this type of in depth simulation and analysis before committing to a project.

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Questions?

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BEFORE THE

ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF SOUTHWESTERN ELECTRIC POWER COMPANY FOR APPROVAL OF A GENERAL CHANGE IN RATES AND TARIFFS	**))))**	**DOCKET NO. 19-008-U**

REBUTTAL TESTIMONY OF

SCOTT E. MERTZ

ON BEHALF OF

SOUTHWESTERN ELECTRIC POWER COMPANY

REDACTED VERSION

AUGUST 20, 2019

TESTIMONY INDEX

REBUTTAL EXHIBITS

EXHIBIT	DESCRIPTION
REBUTTAL EXHIBIT SEM-1	SPP IM DISPATCH
REBUTTAL EXHIBIT SEM-2	CONFIDENTIALWELSH 3 EXAMPLE

I. INTRODUCTION

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Scott E. Mertz, and my business address is 1 Riverside Plaza, Columbus, Ohio 43215.

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

A. Yes. I graduated from the University of Kentucky with a Bachelor of Science degree in Finance and a minor in Economics in 1996. I continued my education at the University of Louisville, receiving my MBA in 1999.

In 2000, I joined American Electric Power Service Corporation (AEPSC) as an Energy Coordinator on their West Coast Trading Desk. In 2003, I was promoted to Lead Trader-Manager for the West Coast Trading Portfolio where I was responsible for the daily management and profitable, measured unwinding of our west coast positions. Upon the exit of our West Coast Trading Portfolio in 2007, I transferred to Regulatory Services. I was promoted to my current role of Regulatory Consultant Staff in 2016.

Q. WHAT ARE YOUR RESPONSIBILITIES AS A REGULATORY CONSULTANT?

A. My responsibilities include advising and supporting Commercial Operations, regulatory teams and witnesses on areas including RTO operations, wholesale markets, and off-system sales. I have provided support related to American Electric Power's (AEP's) Commercial Operations activities in regulatory filings across all of AEP's eleven state jurisdictions and at the Federal Energy Regulatory Commission (FERC).

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY ON BEHALF OF SOUTHWESTERN ELECTRIC POWER COMPANY (SWEPCO OR COMPANY), OR

ANOTHER AEP OPERATING COMPANY WITH ANY REGULATORY COMMISSION?

A. Yes. I have filed testimony before the Indiana Utility Regulatory Commission on behalf of Indiana Michigan Power Company in Cause Numbers 43774 and 43775 regarding PJM market operations and off-system sales margins.

Q. DID YOU FILE DIRECT TESTIMONY IN THIS CASE?

A. No, I did not.

Q. AS AN ADDITIONAL REBUTTAL WITNESS, DO YOU TAKE OVER RESPONSIBILITY FOR RESPONSES TO CERTAIN DATA REQUESTS THAT HAVE BEEN ANSWERED BY OTHER SWEPCO WITNESSES?

A. Yes. I take responsibility for responses to SWEPCO's data requests related to the issues addressed below that were originally answered by SWEPCO witness Mr. Thomas P. Brice, who provided direct testimony in this case.

II. PURPOSE OF REBUTTAL TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is to respond to issues raised by Sierra Club witness Avi Allison, Office of the Arkansas Attorney General (AG) witnesses Scott Norwood, and Michael P. Gorman. I also address an issue raised by Arkansas Public Service Commission (APSC or Commission) General Staff (Staff) witness Judy Kay Lindholm.

Mr. Allison and Mr. Norwood both assert that the Dolet Hills Power Plant (Dolet Hills) incurred net operating losses relative to the Southwest Power Pool Integrated Marketplace (SPP IM) for each year from 2015-2018. Each of their analyses contains

many of the same fundamentally flawed assumptions, and an inaccurate portrayal of the role of the SPP IM. My testimony will show, contrary to Mr. Allison's and Mr. Norwood's claims, that the operation of [redacted] Mr. Norwood's recommendation for a $12.4 reduction in 2018 Dolet Hills operation and maintenance (O&M) expenses rests on a flawed analysis and should be rejected. This latter recommendation from Mr. Norwood is also addressed by SWEPCO witnesses Tommy J. Slater and Thomas P. Brice.

Mr. Allison broadens his flawed analysis to encompass all of SWEPCO's solid fuel units for each year in 2015-2018. Unsurprisingly, his use of essentially the same flawed modeling assumptions employed for Dolet Hills results in his assertion that SWEPCO incurred net operating losses relative to the SPP IM for all of its solid fuel units for all of the years 2015-2018. My testimony will show, contrary to Mr. Allison's claims, [redacted]

Mr. Norwood incorrectly asserts that the Knox Lee and Lieberman units no longer provide value to SWEPCO's customers. Mr. Allison draws this conclusion from his analysis that customers would have been better off if SWEPCO's solid fuel units had never produced a MWh from 2015 through 2018. My testimony will show the inaccuracy of those statements and how they reflect a misunderstanding of SWEPCO's obligation to serve its customers vs. the role of the SPP IM. Mr. Norwood's recommendation that the Company's test year O&M expense related to Lieberman and Knox Lee should be reduced

by $11.9 million should be rejected. This recommendation is also discussed by SWEPCO witnesses Slater and Brice.

In an attempt to strengthen his flawed analysis of SWEPCO's solid fuel net market revenues, Mr. Allison criticizes SWEPCO's solid fuel unit commitment practices and alleges that those practices have led to the uneconomic dispatch of SWEPCO's solid fuel units. My testimony will demonstrate, contrary to Mr. Allison's assertion, that SWEPCO's unit commitment process promotes the plants' active participation in the SPP IM economic dispatch process and has directly led to the positive benefits shown in my testimony.

AG witness Gorman and Staff witness Lindholm both recommend that the Company's ECR Rider should be adjusted to eliminate sharing of all off-system sales (OSS) margins. My testimony will show that the existing sharing mechanism continues to provide benefits to both customers and the Company and should be retained. Ms. Lindholm's recommendation to eliminate OSS margin sharing should be rejected.

AG witness Norwood argues that any replacement 'energy costs and capacity costs' related to the retirement of Welsh 2 since 2016 and in future periods should be calculated and refunded to SWEPCO's customers. My testimony will show such a calculation is unwarranted given the circumstances under which Welsh 2 was retired and based on the benefits of the unit retirement addressed by SWEPCO witness Brice.

Finally, I rebut Staff witness William L. Matthew's recommendation to adjust working capital assets (WCA) from SWEPCO's filed target-based fuel inventory levels to a 13-month average.

Q. ARE YOU SPONSORING ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. Yes, I sponsor the following Rebuttal Exhibits:

REBUTTAL EXHIBIT SEM-1 SPP IM DISPATCH

REBUTTAL EXHIBIT SEM-2 CONFIDENTIAL WELSH 3 EXAMPLE

III. SWEPCO'S GENERATING UNIT OFFERS

Q. HOW DOES THE COMMERCIAL OPERATIONS GROUP ENSURE THAT SWEPCO'S GENERATING UNITS ARE OFFERED INTO THE SPP IM IN A WAY THAT WILL OPTIMIZE THE AMOUNT OF NET MARKET REVENUES EARNED?

A. SWEPCO's generating units are offered into the SPP IM based on each unit's variable energy costs. These variable energy costs are used to create the incremental offer curves that the SPP IM uses in its economic dispatch process. Incremental costs are costs that vary with the output level of the unit. Such incremental generation costs do not represent the total unit production cost but rather the marginal cost for generating the next MWh after a unit has been committed online. Optimization and economic theory dictate that fixed costs should not be included as part of the incremental costs used for unit dispatch decisions. If the cost of dispatching a generator is $1 for the next increment of generation and the revenues created by that next increment of generation are greater than $1, the generation dispatched will produce net benefits for SWEPCO's customers.

SWEPCO units were offered in the SPP IM correctly based on their incremental energy costs and the dispatch of the units resulted in positive revenues above those costs. [redacted] This fact

demonstrates that SWEPCO has sought and will continue to seek opportunities in the SPP IM to produce net energy revenues for the benefit of customers.

IV. SWEPCO SOLID FUEL UNITS' NET MARKET REVENUES

Q. HOW DO YOU RESPOND TO SIERRA CLUB WITNESS ALLISON'S CLAIM THAT SWEPCO'S SOLID FUEL UNITS HAVE EACH LOST MORE THAN $200 MILLION RELATIVE TO THE MARKET FROM 2015 – 2018?

A. The basic premise of his analysis is an apples and oranges comparison that produces a value that is misleading and inaccurate. Mr. Allison's calculations fail to accurately compare the energy and ancillary service revenue that SWEPCO received in the day-ahead and real-time markets with the incremental costs that were actually used to generate those revenues. The incremental dispatch costs used by SWEPCO to participate in the SPP IM, and receive energy and ancillary service revenue, are primarily variable fuel and other variable production-related costs.

Instead, Mr. Allison's calculations incorrectly include costs that are fixed (*i.e.*, costs that do not vary with the output level of the unit). Fixed costs will be incurred whether or not a unit is dispatched. Other values considered by Mr. Allison have been significantly overstated. His methodology varies slightly between Dolet Hills and the remaining solid fuel units (Pirkey, Flint Creek, Welsh 1 and Welsh 3), but is effectively the same. As a result, the same flaws in his Dolet Hills analysis are used in the analysis of all of SWEPCO's solid fuel units.

Q. WHAT INPUTS DOES MR. ALLISON INCLUDE IN HIS BASE ANALYSIS OF DOLET HILLS?

A. The revenues Mr. Allison uses for his net market revenue calculation are the energy and ancillary service revenues earned by each unit through its participation in the SPP IM. On the cost/expense side of the calculation, Mr. Allison uses total O&M costs, total fuel costs, and capital costs incurred during 2015 through 2018. Mr. Allison has correctly identified the energy and ancillary service revenues, but Table 1 below shows the significant errors he has made regarding the expense side of the equation.

Table 1

TOTAL O&M	O&M is necessary to keep the units ready and able to meet the needs of SWEPCO"s customers. The use of total O&M incorrectly inflates the expenses used in Mr. Allison's calculation. Please refer to the rebuttal testimony of Company witness Mr. Slater for a more detailed discussion of O&M expenses.
TOTAL FUEL COST	The economic operation of the solid fuel units is based on the variable, incremental cost of fuel - NOT - the total cost of fuel found in the FERC Form 1. The use of total fuel cost significantly inflates the expenses used in Mr. Allison's analysis.
CAPITAL COST	This cost is not applicable to Mr. Allison's analysis. Their only rationale for being included appear to be to further inflate the expense side of the calculations. Capital costs are much more appropriately evaluated within the context of system resource planning, as described in the rebuttal testimony of Company witness Mr. Becker.

Mr. Allison's flawed analysis produces an inaccurate calculation of SWEPCO's solid unit's net market revenues.

V. CORRECT NET MARKET REVENUES OF SWEPCO'S SOLID FUEL UNITS

Q. PLEASE DESCRIBE THE RESULTS OF YOUR ANALYSIS OF THE NET REVENUES OF SWEPCO'S SOLID FUEL UNITS DURING 2015-2018.

A. Each of SWEPCO's solid fuel units earned positive Net Market Revenues during the period 2015-2018. [redacted]

Q. HOW DID YOU CALCULATE THE BENEFITS SHOWN ABOVE?

A. Net Market Revenues are calculated by subtracting the variable cost of production from the market revenues. On an hourly basis for each unit, the variable production costs (variable fuel, variable O&M, NOx, SOx and chemicals) were compared against the ancillary and energy revenue received in that hour. The analysis therefore calculated either a net positive or negative market revenue for each hour. The data presented above represent an aggregation of the hourly data.

Q. IN WHAT WAY DOES YOUR ANALYSIS ACCURATELY CALCULATE THE NET MARKET REVENUES FOR SWEPCO'S SOLID FUEL UNITS?

A. The net revenue calculation is based on the variable costs incurred to produce the variable revenue received for each unit. For example, the assumption that all fuel costs are incremental is particularly incorrect for SWEPCO's Pirkey and Dolet Hills plants, where a substantial portion of the costs to mine the lignite fuel for these plants does not vary with

the output level of the generating plants. In order to accurately calculate the net market revenues of SWEPCO's solid fuel units, it is only appropriate to use the variable cost of fuel and not the total cost, which would include fixed costs. Mr. Allison fails to make this distinction in both his net revenue analysis and his 2018 hourly analysis of SWEPCO's solid fuel units and therefore reaches conclusions that are not valid. Mr. Norwood also repeatedly fails to make this distinction; in particular, when he alleges that the "average cost of fuel for Dolet Hills in the test year is more than double the current market price of natural gas." (Norwood Direct Testimony, page 34, lines 9-10).

VI. SWEPCO'S RESPONSIBILITIES VS. SPP'S ROLE

Q. HOW HAS THE IMPLEMENTATION OF THE SPP IM IMPACTED SWEPCO'S OBLIGATION TO SERVE THE NEEDS OF ITS CUSTOMERS?

A. The SPP IM has not replaced SWEPCO's obligation to provide electric service to its customers. The SPP IM has not assumed the obligation to ensure that SWEPCO has an appropriate portfolio of resources at all times to provide for the capacity and energy needs of its customers. The SPP IM has not replaced the resource planning function that SWEPCO fulfills for its customers. What the SPP IM has provided is an additional tool for SWEPCO to optimize its portfolio of resources on a day-ahead and real-time basis for the economic purchase and sale of energy.

Q. DO THE RECOMMENDATIONS OF MR. NORWOOD AND MR. ALLISON RECOGNIZE THE DISTINCTION BETWEEN SWEPCO'S OBLIGATION TO ITS CUSTOMERS AND THE ROLE OF THE SPP IM?

A. No, those recommendations do not appear to do so. Mr. Norwood's recommendation to exclude the O&M expenses of Knox Lee and Lieberman based simply on recent SPP IM energy prices completely ignores the difference between the long-term obligations of SWEPCO and the limited, short-term function of the SPP IM. The Knox Lee and Lieberman units, as well as the solid fuel units discussed by Mr. Allison, have been and continue to play a valuable role in SWEPCO's diversified portfolio of resources. The capacity provided by these units help SWEPCO to meet its SPP planning reserve obligation and must be properly maintained and be operational when called upon as discussed by SWEPCO witness Slater. Also see the testimony of SWEPCO witness Brice.

VII. SWEPCO'S MARKET PARTICIPATION

Q. DO YOU AGREE WITH MR. ALLISON'S CLAIM THAT SWEPCO'S UNIT COMMITMENT PRACTICES HAVE LED TO MILLIONS OF DOLLARS IN LOSSES?

A. No, I do not. Mr. Allison's assertion is not supported by SPP's dispatch methodology, the market awards received by SWEPCO's solid fuel fleet, or the positive net revenue earned by SWEPCO's solid fuel units.

Q. DO YOU HAVE ANY GENERAL REMARKS REGARDING THE ACCUSATIONS AND ALLEGATIONS MR. ALLISON MAKES IN REGARD TO SWEPCO'S PARTICIPATION IN THE SPP IM?

A. Yes, I do. Throughout section 6 of his Direct Testimony, Mr. Allison claims that SWEPCO generally does not operate its solid fuel units in regard to "market forces, economic need, or reliability requirements." (Allison Direct, page 39, line 7). He asserts that SWEPCO's

solid fuel units incurred $435 million in net losses relative to market revenues – a steady stream of losses for each of the 5 units, for each year, for four years. He confidently asserts that "SWEPCO's decision-making has consistently resulted in SWEPCO incurring net operational losses on behalf of its customers." (Allison Direct, page 40, line 16-17). Mr. Allison's claims reach their crescendo when he asserts that "these results suggest that, in the absence of reliability and contractual constraints, SWEPCO customers would have been better off if SWEPCO had not operated any of its coal units *at all* over the last four years, even if the Company had to continue paying O&M and capital costs." (Allison Direct, page 44, lines 7–10). Regarding Mr. Allison's stream of assertions, I must respectfully disagree. Mr. Allison's incorrect claims, assertions and conclusions rest upon nothing but flawed analytics and an incorrect and incomplete understanding of SPP's role and the ways in which SWEPCO works within the framework provided by the SPP IM.

Q. DO YOU AGREE WITH MR. ALLISON'S 2018 ANALYSIS AND CONCLUSIONS COMPARING THE HOURLY LOCATIONAL MARGINAL PRICE (LMP) AGAINST THE AVERAGE ANNUAL PER-MWH FUEL COSTS OF EACH UNIT?

A. No, I do not. Mr. Allison's approach totally ignores and contradicts basic economic fundamentals. Mr. Allison incorrectly analyzes the hourly economics of a unit by comparing the unit's hourly day-ahead LMP against its average annual per-MWh fuel cost. There are several significant errors he makes in this comparison that make the results of his analysis flawed and incorrect.

Q. WHAT ARE THE MAJOR FLAWS CONTAINED IN MR. ALLISON'S HOURLY EVALUATION OF SWEPCO'S SOLID FUEL UNITS?

A. First, his use of the total fuel cost incorrectly includes fixed costs instead of only using variable costs. This calculation error mirrors the incorrect fuel cost calculation he made in his annual analysis of net market margins. Secondly, the use of average annual fuel costs ignores the fact that the fuel price will be changing just like the LMPs. The hourly cost of the power produced by SWEPCO's units varies based on the amount of power it is producing each hour. Starting with incorrect fuel prices, and then comparing hourly LMPs to an annual average fuel cost produces inaccurate results of a unit's hourly cost versus its hourly revenue.

Q. WHAT ARE THE RESULTS OF THE HOURLY NET REVENUE ANALYSIS AFTER CORRECTING FOR MR. ALLISON'S FLAWED ASSUMPTIONS?

A. I corrected for those errors using the actual hourly unit costs and each unit's revenues. I then reproduced Mr. Allison's analysis to determine the number of the operating hours in which the cost of the unit was either higher or lower than the revenue of the unit. The corrected values show SWEPCO's solid fuel units across the board operated more often in hours in which their revenues exceeded their production costs than incorrectly asserted by Mr. Allison flawed analysis. [redacted]

[redacted]

Q. DURING THE HOURS SWEPCO'S UNITS RECEIVED LESS REVENUE THAN THEIR VARIABLE OPERATING COST, DOES THAT MEAN THAT SWEPCO IS RUNNING THE UNIT UNECONOMICALLY?

A. No, it does not. Suppose a unit sold 200 MWh for six hours in a row at a loss of $2 per MWh for a total loss of $2,400; but during the next four hours, it sold 400 MWh, each for a profit of $5 per MWh for a total gain of $8,000. So, although the unit operated at a loss for more hours than the number of hours it operated at a gain, it still made a net profit over the total period. As shown in Table 2 of my testimony, a detailed analysis of the hourly margins shows that [redacted]

Q. IS MR. ALLISON CORRECT IN STATING THAT SWEPCO IS NOT AN ACTIVE PARTICIPANT IN SPP'S ECONOMIC DISPATCH PROCESS WHEN IT SELF-COMMITS ITS UNITS?

A. No, he is not. When SWEPCO self-commits units, it only self-commits the unit at its economic minimum. As provided in REBUTTAL EXHIBIT SEM - 1, SPP's Market Protocols plainly show that the output between the unit's economic minimum and

maximum output levels are considered by SPP to be available and are participants in SPP's economic dispatch process. In addition to informing SPP that the unit will be running at its economic minimum, SWEPCO also submits an offer curve based on the unit's incremental production costs. Regardless of the unit designation, if SPP awards or clears the unit at an output level higher than its economic minimum, then the unit was economically dispatched in the market. The average dispatch range for the solid fuel units between their economic minimum level and maximum output level covers 58% of the units output range – meaning regardless of the unit's commitment status, the majority of the unit's capability is made available to SPP for economic dispatch.

Q. WHAT WERE SOME OF THE FACTORS TAKEN INTO CONSIDERATION BY SWEPCO IN THE UNIT COMMITMENT DECISIONS RELATED TO ITS SOLID FUEL UNITS?

A. Because of the short time frame of the SPP IM Day-Ahead Market, SWEPCO typically self-schedules the solid fuel units to avoid unnecessary cycling of the units and to avoid the related start-up costs. In other words, the SPP Day-Ahead Market only commits one day out. The impact of this fact on a generator with longer startup lead times, such as SWEPCO's solid fuel plants, is that these plants need to be online at their economic minimums to effectively be considered in the Day-Ahead Market. Therefore, expected market revenues and the economics of the unit over a period longer than the next day are considered in the unit commitment decisions for these plants.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW SWEPCO'S SOLID FUEL UNITS ARE STILL ACTIVE MARKET PARTICIPANTS EVEN WHEN THEY ARE SELF-COMMITTED?

A. [redacted]

VIII. OSS MARGIN SHARING

Q. DO YOU AGREE WITH THE TESTIMONY OF AG WITNESS GORMAN AND STAFF WITNESS LINDHOLM THAT OSS MARGIN SHARING SHOULD BE ELIMINATED?

A. No, I do not. Ms. Lindholm correctly notes that the implementation of the SPP IM has impacted the manner in which OSS transactions take place. However, the implementation of the SPP IM has increased the complexity of making OSS margins, making the importance of the current OSS margin sharing incentive mechanism even more important than it has been in the past.

Q. PLEASE PROVIDE AN EXAMPLE OF THE ACTIONS SWEPCO TAKES TO OPTIMIZE THE LEVEL OF OSS MARGINS.

A. As discussed previously in my testimony, the scope and objective of the SPP IM is limited to determining the least-cost solution to meet the system reliability needs, the energy needs and the reserve requirements needed for the next operating day.

SWEPCO's optimization activities extend over a much longer time frame. For example, during a low demand period, such as those often occurring over the weekends, the variable cost of operating a unit may exceed the market clearing price for the next operating day as calculated by SPP's economic dispatch model. In other words, in the Day-Ahead Market, this unit will not be selected to run by SPP and would instead shut down. However, as one extends the time frame under which the unit's economic operation in relation to the market is evaluated, then the decision to run or shut down the unit over the weekend becomes much more complex. For example, to properly evaluate the unit economics requires information such as unit shut down and startup costs, forecasted demand not just for the next day but for many days in the future, corresponding forecasted day-ahead clearing prices, and potential performance issues for other units within SWEPCO's portfolio. This optimization process occurs outside the SPP IM responsibilities of SWEPCO as an SPP market participant, and relies on the combined expertise and coordination of the many groups within AEPSC for its success. These groups include Meteorology, Fuel Procurement, Generation, Trading, Bid Development, and LMP and Load Forecasting.

Q. HAS SWEPCO SHOWN ITS ABILITY TO OPTIMIZE ITS GENERATION RESOURCES WITHIN THE SPP IM FRAMEWORK?

A. Yes, it has. As discussed earlier in my testimony, the Net Market Revenues earned by SWEPCO's solid fuel fleet over the last four years demonstrate SWEPCO's ability to optimize resources within the SPP IM. The current sharing mechanism provides an appropriate incentive for the Company while still providing the majority of the benefits, including OSS margins, to SWEPCO's customers. Mr. Gorman's and Ms. Lindholm's recommendations to eliminate the existing sharing mechanism should be denied.

IX. WELSH UNIT 2

Q. HAVE YOU MADE A COMPARISON OF THE SIGNIFICANCE OF THE OUTPUT RESTRICTION PLACED ON WELSH 2 THAT WAS MEMORIALIZED IN THE SIERRA CLUB AGREEMENT DISCUSSED IN THE TESTIMONY OF AG WITNESS NORWOOD?

A. Yes, I have. However, I should point out that the Company was committed to the output restriction long before the settlement agreement with the Sierra Club, as described by SWEPCO witness Brice. As to Mr. Norwood's comparison, I reviewed the output levels at all three Welsh units, both before and after the limitation on Welsh 2 was implemented. The Table 4 below shows that during the first three years reviewed, 2010-2013, Welsh 2 operated at a very similar level to Welsh 1 and Welsh 3.

Table 4

	Net Generation (MWhs)		
	Welsh 1	Welsh 2	Welsh 3
2010	3,425,963	3,657,448	3,748,150
2011	3,660,090	3,557,682	3,670,294
2012	3,428,542	3,316,602	3,536,440
Average	**3,504,865**	**3,510,577**	**3,651,628**

The second period reviewed, 2014-2016, shows how Welsh 2 operated compared with its sister units Welsh 1 and Welsh 3. If the output limitation imposed significant changes in the unit's capacity factor in those years, I would expect to see the Welsh 2 output level show a material drop in comparison to units 1 and 3. However, the Table 5 below does not support that conclusion. During those years, the Welsh 2 output did drop – as did the output of Welsh 1 and 3. This suggests that the limit put on Welsh 2 was not the key factor in the decrease in output of the unit in those years. Accordingly, the limitation did not have a significant impact on the economic dispatch of SWEPCO's resources.

Table 5

	Net Generation (MWhs)		
	Welsh 1	Welsh 2	Welsh 3
2013	2,945,428	2,689,878	3,118,287
2014	2,694,724	2,426,865	2,859,853
2015	2,019,971	2,148,740	1,962,061
Average	**2,553,375**	**2,421,828**	**2,646,734**

Q. DO YOU AGREE WITH MR. NORWOOD'S RECOMMENDATION THAT SWEPCO BE REQUIRED TO CALCULATE POTENTIAL ENERGY AND CAPACITY REPLACEMENT COSTS RELATED TO THE RETIREMENT OF WELSH 2?

A. No, I do not. My analysis above shows that the Welsh 2 unit output decrease was primarily driven by the market dispatch and not by the capacity factor limitation. Further, as explained by SWEPCO witness Brice, the decision to retire Welsh 2 was based on a combination of interrelated factors that affected the Company's resource selections. Any attempt to quantify potential energy and capacity replacement costs due to the retirement

of Welsh 2, if any, would ignore other factors that led to its retirement. Mr. Norwood's recommendation should therefore be rejected by the Commission.

X. FUEL INVENTORY

Q. DO YOU AGREE WITH STAFF WITNESS MATTHEWS' REDUCTION OF THE COAL AND LIGNITE BALANCES?

A. No, I do not. Mr. Matthews recommends that the coal and lignite balances should be based on the previous 13-month average amount consumed. His suggestion, if adopted, to use the average amount consumed instead of the Company's target inventory would negatively impact SWEPCO's ability to reliably serve the needs of its customers, as I explain below, and should be rejected.

Q. HOW DOES SWEPCO DETERMINE ITS TARGET FUEL INVENTORY?

A. SWEPCO's main focus in producing an inventory target is the number of tons required to reliably meet peak demand periods. To establish these levels, SWEPCO looks at numerous factors that could affect the supply of fuel to a plant, such as the source of fuel supply, shipping methods and lead times, on-site storage capabilities, and typical plant capacity factors, to determine the proper amount of fuel storage to ensure each plant has sufficient coal stored to minimize operational risk for all conditions that could cause supply disruptions. Additionally, the type, number, and capacity of the modes of delivery are important considerations in establishing the inventory target.

Q. ARE THERE NEGATIVE IMPLICATIONS FOR SWEPCO'S CUSTOMERS IF A 13-MONTH HISTORIC AVERAGE BURN RATE IS USED TO SET SWEPCO'S INVENTORY TARGETS?

A. Yes, there are. Using the 13-month historic average of fuel consumed increases reliability risk for SWEPCO's customers. First, making use of a 13-month consumption calculation contains the implied assumption that the historical time period experienced operating conditions that will persist into the future. Factors such as weather or unit outages could easily make future conditions differ from the historic 13-month period. Furthermore, an average burn rate misses the peak coal inventory needed during heavier use periods of the year. A scenario could happen in which a supply disruption during a high generation month would result in the plant running out of coal as a result of using an average burn rate to set the target inventory level. The most prudent way to ensure the necessary inventory is available is to use a forward-looking view of the amount of inventory required to ensure reliability for SWEPCO's customers. Mr. Matthews' proposed adjustment should therefore be denied.

XI. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that a copy of the foregoing Rebuttal Testimony was electronically served upon all parties of record via the Commission's EFS system on this 20th day of August 2019.

/s/ Stephen K. Cuffman
Stephen K. Cuffman

SPP Southwest Power Pool

Market Protocols

SPP Integrated Marketplace

Revision 70

MAINTAINED BY

Market Design

PUBLISHED: 12/16/2010

LATEST REVISION: 8/13/2019

status will default to outage and the Resource will not be available for commitment or dispatch during the outage period. Valid Commitment Status and Dispatch Status selections are:

4.2.2.2.1 Commitment Status

(1) **Market** – The Resource is available for SPP economic commitment if it is off-line;

(2) **Self** – The Market Participant is committing the Resource and SPP should include it as committed in either the DA Market and/or RUC as specified;

(3) **Reliability** – The Resource is off-line and is only available for commitment by SPP if there is an anticipated reliability issue;

(4) **Outage** – The Resource is unavailable due to a planned, forced, maintenance or other approved outage. The outage must be documented using the outage scheduler tool described under Section 4.1.7.

(5) **Not Participating** – The Resource is otherwise available but has elected not to participate in the DA Market. This option is not available for use for RTBM Offers.

a. A Commitment Status of Not Participating does not automatically prevent a Resource from being cleared for offline Supplemental Reserve.

4.2.2.2.2 Dispatch Status

There is a Dispatch Status for each product (Energy, Regulation-Up Service, Regulation-Down Service, Spinning Reserve and Supplemental Reserve) as follows:

(1) **Energy**

(a) **Market** – The Resource is available for SPP economic dispatch if committed;

(b) **Not Qualified** – The Resource is not qualified to be dispatched to provide Energy. This status is valid for only a Demand Response Resource or External Dynamic Resource that is not available for Energy dispatch but is available to be cleared for Regulation-Up Service, Regulation-Down Service and/or Contingency Reserve. Use of the Not Qualified Status is required for an External Dynamic Resource in the Eastern Interconnection. Resources with this submitted Energy Dispatch Status are not subject to the charges and credits calculated under Section 4.5.9.19 or the deviation calculations under Sections 4.5.9.10(1)(a.5) and 4.5.9.10(1)(a.7).

SOUTHWESTERN ELECTRIC POWER COMPANY
DOCKET NO. 19-008-U
REBUTTAL EXHIBIT SEM-2

Welsh 3 Example

HIGHLY SENSITIVE AND CONFIDENTIAL

Recent Changes to U.S. Coal Plant Operations and Current Compensation Practices

National Association of Regulatory Utility Commissioners | January 2020

Phillip Graeter, Energy Ventures Analysis, Inc.

Seth Schwartz, Energy Ventures Analysis, Inc.

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NARUC

National Association of Regulatory Utility Commissioners

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Executive Summary

Over the last decade, the U.S. electric power sector has gone through one of the most dramatic changes in its existence. The combination of low natural gas prices as a result of the shale gas revolution and significant reduction in construction and operating costs for renewable resources, in part due to federal tax credits such as the production tax credit and investment tax credit mainly benefitting wind and solar, respectively, has resulted in a significant shift away from coal-fired generation, and instead towards natural gas and renewable generation.

Furthermore, the operating profile of existing coal-fired electric generating units has changed significantly. As new natural gas combined cycle plants have become increasingly more efficient and cheaper to operate than older existing coal-fired power plants, coal units continue to lose baseload generation share and more frequently operate as load-following, or cycling, resources. These trends are of particular importance to state public utility commissions (commissions). Functioning as economic regulators, commissions oversee investments in a reliable, efficient system while balancing emissions goals, customer demands, and other policy objectives. Changes to coal plant operations as a result of increased competition from other fuel sources may have a bearing on system reliability and economics, and therefore constitute an important area for commissions to monitor.

Increased cycling operations of coal plants, including more frequent startups and shutdowns, as well as faster changes in unit output, have a considerable impact on the reliability and cost of the plant. More frequent cycling increases wear-and-tear of plant equipment and can lead to shorter equipment lifespan due to thermal fatigue, thermal expansion, increased corrosion, and increased cost of start-up fuel. Without proper maintenance of the plant during these operations, unexpected plant outages become more frequent.

Despite the increase in plant operating costs due to cycling, there exist numerous options for plant operators to minimize the financial impact and optimize the plant's operation. One option for mitigating the effects of flexible operation is for plants to implement system modifications that recover plant efficiency lost to continuous cycling operation. Examples include sliding pressure operation, variable-speed drives for the primary cycle and auxiliary equipment, and boiler draft control schemes and operating philosophy.

Other options include establishing and following cycle chemistry guidelines for flexible operations, accurate damage estimation, flexible operation studies, and plant operator coaching. Additionally, areas to minimize coal plant cycling costs, outside the control of coal plant operators, include the increased deployment of energy storage and demand-side management resources and curtailing wind and solar generation during times of high generation or low demand.

Most of the cycling cost mitigation strategies require significant capital investment. However, recent market developments have undercut the profitability of existing coal-fired power plants and reduced the amount of working capital plant owners are able or willing to spend on the maintenance necessary to ensure plant reliability.

While they are currently being discussed, no specific market mechanisms to compensate unit flexibility provided by fossil fuel power plants exist in the Electric Reliability Council of Texas (ERCOT) and Southwest Power Pool (SPP) power markets, the two independent system operators (ISO) with the largest share of intermittent renewable energy resources in their generation mix. However, without any additional source of revenue for coal plants (e.g., for providing necessary operational flexibility for these power markets), more coal retirements due to poor economics

are likely, increasing the risk of potential power outages in states like Texas. In areas with regulated utilities, the increased cost of coal plant cycling is being passed on to utility customers. Any market mechanisms that financially reward the flexibility of coal-fired generating units will arguably result in lower overall system costs while ensuring the reliable operation of the electric power grid.

Thoughtful market mechanisms that financially compensate coal-fired generating units for providing essential market balancing attributes, such as short-term generation flexibility, could arguably result in lower electric retail rates for end-use customers while equally, if not more importantly, helping to ensure reliable operation of the nation's electric power grid.

Introduction

Over the last ten years, the U.S. electric power system has gone through significant changes, creating new challenges for various stakeholders, including state public utility commissions (commissions). Following the Great Recession from 2007 to 2009, demand for electricity has mostly remained flat due to changes in consumer behavior and a heightened focus on energy efficiency and conservation. Additionally, technical advancements in hydraulic fracturing and horizontal drilling have revolutionized the U.S. natural gas and oil industry, resulting in record domestic production of natural gas and crude oil.

Subsequently, pricing for both commodities has decreased substantially. The shale gas revolution has created an environment where natural gas-fired power plants in the U.S. are becoming increasingly more cost-competitive with their coal-fired counterparts, resulting in a major shift from coal to natural gas generation.

Additionally, climate change has arguably been one of the most discussed topics of this decade and will likely be a leading global issue going forward. Societal pressure to move to zero-emissions energy sources, combined with renewable energy mandates, tax incentives for renewable development, and significant cost reductions for wind and solar technologies, have resulted in the continued addition of new wind and solar generating facilities across the country. With intermittent resources accounting for over one-third of total generation in some states, traditional baseload generators have been forced to be more flexible in their operating profile and complement fluctuations in generation from intermittent renewable sources.

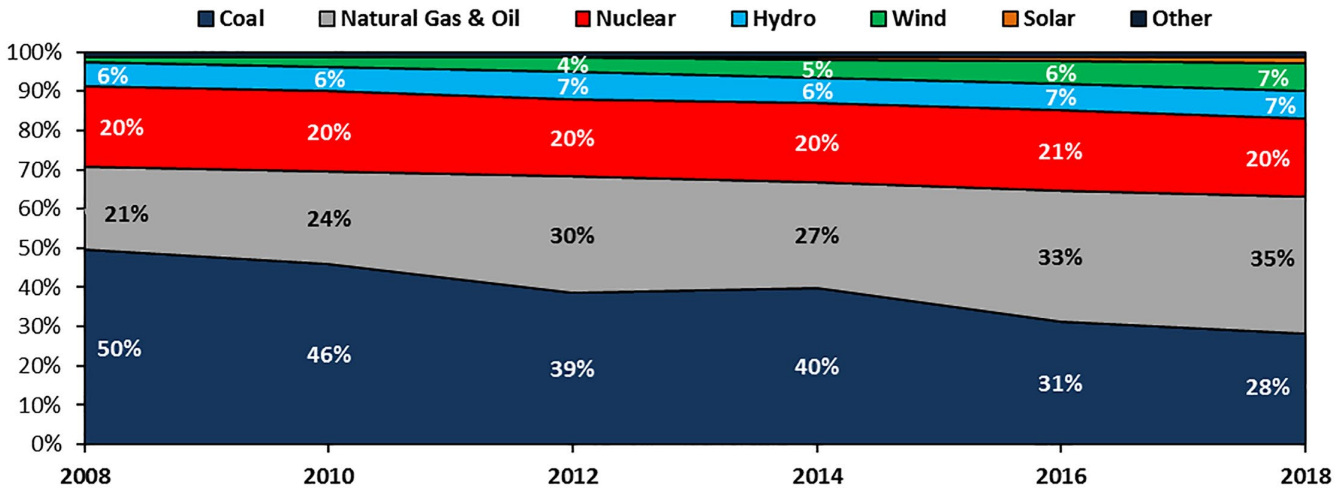
These conditions have resulted in new challenges for commissions. As economic regulators, they are charged with overseeing the reliable, safe, and affordable operation of the electricity generation and delivery system. The asset life for electric generation can span decades, making today's decisions impactful for customers well into the future. Similarly, commissioners inherit a system of assets at various stages in their operating lifespans. As new generation sources become competitive with coal — a fuel that was, for much of the twentieth century, one of the cheapest sources of electricity — commissions can benefit from two things: (1) a more complete understanding of how coal generation is or can be responding to competition, and (2) a discussion of an important attribute of the electricity system: flexibility. This paper focuses on operational changes experienced by U.S. coal-fired power plants as a result of high renewable penetration. The report also explores how fossil fuel plant flexibility is currently procured and compensated. Future research in this area may consider options for states to maintain flexible, reliable, and affordable electricity.

Overview of the Changes in the U.S. Electric Power System between 2008 and 2018

Over the last decade, the U.S. electric generating fleet has experienced some significant changes. Cheap natural gas, as a result of the shale gas revolution and falling construction and production costs for new wind and solar generation, in conjunction with public policy initiatives supporting renewables, have caused a shift from coal-fired power generation to natural gas and renewable generation.

As shown in **Exhibit 1,** in 2008, electric generation from coal-fired power plants accounted for 50% of total U.S. electric generation. Natural gas and oil generation accounted for 21%, and non-hydro renewable generation accounted for less than 2% of total generation. A decade later, the generation mix has changed dramatically. In 2018, coal-fired power plants accounted for just 28% of the total electricity produced in the U.S., while natural gas and oil's share increased to 35% and non-hydro renewable's share to 10%. This shift, which shows little sign of slowing, is creating both new opportunities and challenges for stakeholders.

EXHIBIT 1: U.S. ELECTRIC GENERATION[1] MIX – 2008 TO 2018[2]



In 2018, U.S. coal generation dropped by more than 40% from 2001 levels, while natural gas and renewable generation more than doubled their combined generation during the same period. Since renewable generation from wind and solar is generally considered non-dispatchable and is widely perceived as a nominally zero marginal cost resource, any available generation from these resources is on a "take-when-available" agreement and is displacing baseload coal generation at the bottom of the dispatch stack.[3]

In addition, the fall of natural gas prices and the resulting wave of new natural gas combined cycle power plants (CCGTs) have increased the competition between coal-fired and natural gas-fired generation for meeting baseload power needs. As a result of the shift from coal to natural gas and non-hydro renewables and resulting change in the

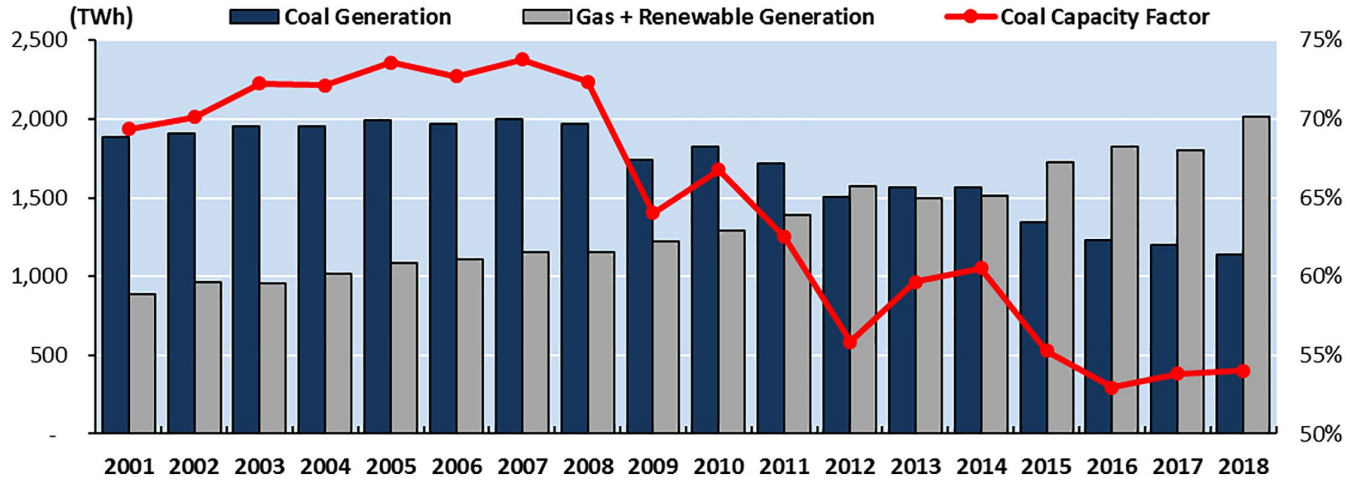
1 Generation throughout this report refers to the amount of electricity generated in a certain period measured MWh. Capacity refers to the maximum generation output a unit can generate in one hour, measured in MW.

2 Source: Department of Energy - Energy Information Administration (EIA) Annual Form-923 data

3 Some power markets have experienced times when renewable generation was greater than the total electricity demand at that time, forcing the system operator to curtail (i.e., stop from generating electricity) renewable generation.

economic dispatch order, coal plant utilization rates, also referred to as capacity factors,[4] have dropped from a high of 74% in 2007 to just 54% in 2018, as shown in **Exhibit 2.**

EXHIBIT 2: U.S. COAL GENERATION AND CAPACITY FACTOR VS. COMBINED NATURAL GAS & RENEWABLE GENERATION[5]



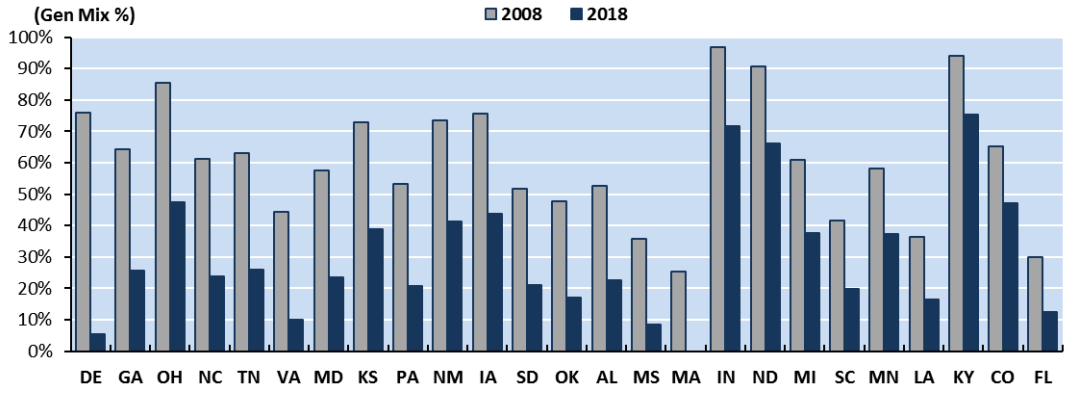
It should be noted that the magnitude of this shift from coal to natural gas and non-hydro renewable generation varies from state to state. From 2008 to 2018, all but one state (Alaska) experienced a drop in their coal generation share. **Exhibit 3** shows the top 25 states with the largest reduction in coal generation share between 2008 and 2018. Some states have seen their in-state coal generation share drop from the most dominant to just a minor role in 2018. For example, Virginia's coal fleet accounted for more than half of the total in-state generation in 2003. By 2018, that share dropped below 10%, while natural gas generation increased from 14% to 55% over the same period.

Other states with significant coal generation declines include Delaware (-71% generation share decline between 2008 and 2018), Georgia (-39%), and Ohio (-38%). On the other hand, states like Washington, Arkansas, and Nebraska, have seen only modest declines (<4%) of coal generation over the same period.

4 Capacity factor measures the utilization of a generating unit over time. For example, an electric generating unit with a generating capacity of 100 MW is capable of generating 100 MW per hour, or 876,000 MWh per year. If the same unit only generated 438,000 MWh during the year, it only generated 50% of the electricity it is theoretically capable of. Therefore, its capacity factor is 50%.

5 Source: Annual EIA Form-923 and Form 860 Data

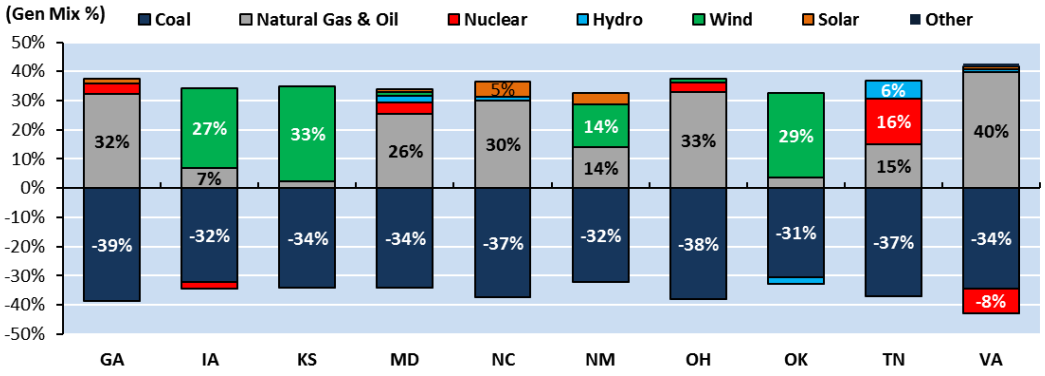
EXHIBIT 3: TOP 25 DECLINES IN COAL GENERATION SHARE BY STATE – 2008 VS. 2018[6]



While the magnitude of coal displacement varies from state to state, so does the source of replacement energy, as shown in **Exhibit 4.** For example, in Georgia, the vast majority of the 39% loss in coal generation over the last 11 years has been replaced by natural gas generation. In states like Iowa, Kansas, and Oklahoma, which have substantial wind resources, coal has been displaced predominantly by wind generation.

Lastly, another group of states has used falling costs of natural gas and renewable generation to diversify their in-state generation mix significantly. For example, New Mexico replaced the loss of 32% of coal generation share with equal parts natural gas and wind generation (14% each), as well as 4% from new solar generation. Tennessee, which is home to the recently-completed Watts Bar 2 nuclear reactor, also added significant amounts of natural gas and hydro generation to displace coal generation.

EXHIBIT 4: REPLACEMENT OF COAL GENERATION MIX SHARE BY OTHER FUELS FOR VARIOUS STATES – 2008 VS. 2018[7]



6 Source: Annual EIA Form-923 Data

7 Source: Annual EIA Form-923 Data

Operational Changes at Coal Plants between 2008 and 2018

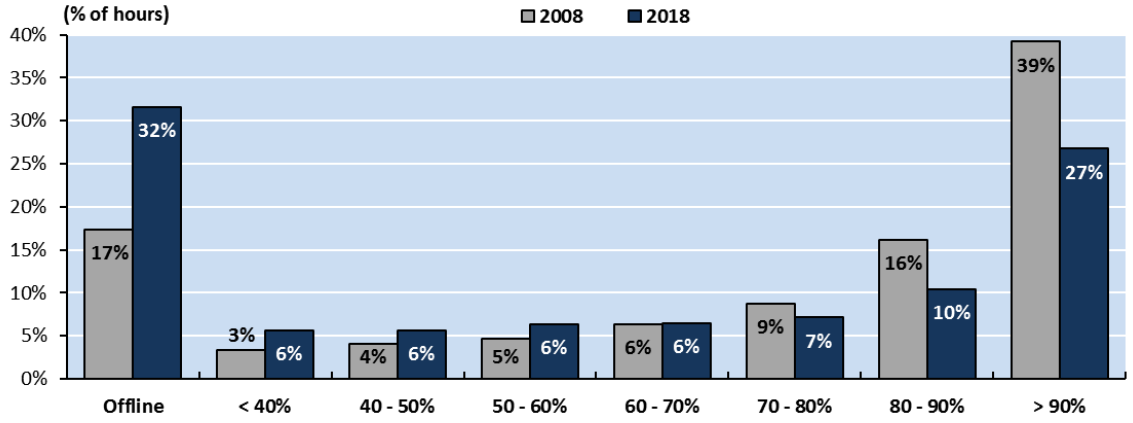
These dramatic changes in the generation mix have significant impacts on the operation of the remaining coal-fired generating fleet. To highlight these differences, this report presents an in-depth analysis of hourly gross generation data from EPA's Continuous Emission Monitoring System (EPA CEMS) for all operating coal-fired electric generating units (EGUs) in 2008 and 2018. Plants with only partial-year data (due to reporting requirements, in-year retirements, or online dates) and glaring reporting errors were excluded. In total, the hourly generation dataset included 8.1 million observations for 927 EGUs across 43 states in 2008 and 4.7 million observations for 531 EGUs across 42 states in 2018. 2008 marked the last year of historically "normal" coal plant operation (as indicated by the 72% capacity factor for the U.S. coal fleet shown in **Exhibit 2**) and was, therefore, chosen as comparison to current market conditions.

The analysis focused on four key metrics for coal plant operations: (1) gross capacity factor by segment, (2) number of hot, warm, and cold starts, and average duration that the coal unit was offline, (3) maximum turndown rate, defined as the *lowest* safe power output level, and (4) hourly ramping rates. Differences in these metrics were analyzed on a state level, in addition to the age and size of the coal plant. Highlights of the results are presented below.

As shown in **Exhibit 5,** the distribution of hourly capacity factors for the U.S. coal fleet has changed dramatically over the last decade. As described earlier, the annual capacity factor for the U.S. coal fleet dropped from 72% in 2008 to 54% in 2018. However, annual capacity factors do not provide sufficient detail on the actual operation of individual coal-fired EGUs. For example, an EGU that operates at a 100% capacity factor for half of the year, while offline the other half, has the same capacity factor as an EGU cycling equally between 30% and 70% capacity factors for the entire year. Exhibit 5 highlights a few significant shifts in operations for the U.S. coal fleet.

First, as a result of higher wind penetration, increased competition with natural gas-fired EGUs, and overall higher ramping and startup and shutdown costs (as described later in this report), coal plant operators in 2018 more often chose to keep the EGU offline and only brought it online when favorable market conditions persisted over a more extended period of time, such as high wholesale power prices during elevated demand periods. Therefore, coal units were offline an additional 14% of the time compared to 2008. Second, when online, coal-fired EGUs in 2018 operated at much lower capacity factors than their 2008 counterparts. Coal units operated only 37% of the time above 80% of their gross capacity, which is considered the highest efficiency range for most coal-fired EGUs. In 2008, the U.S. coal fleet operated during more than 55% of all hours in that same range. Additionally, coal plants in 2018 operated more often at lower capacity factors near maximum turndown levels, the utilization level at which boiler temperatures and pressures are being maintained so that the unit can ramp up more quickly in response to changes (increased demand) in electric load and/or decreased wind output. In 2018, coal plants operated more than 18% of the time at capacity factors below 60%, compared to just 12% of the time in 2008.

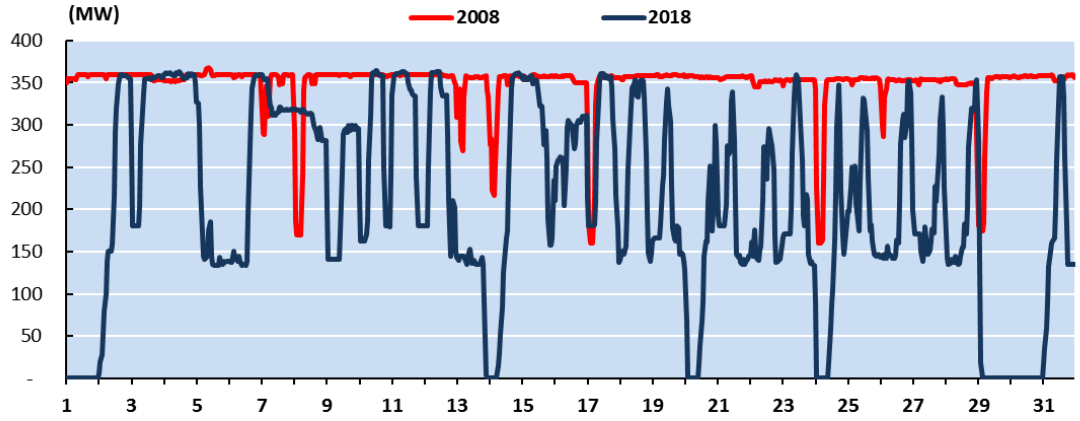
EXHIBIT 5: DISTRIBUTION OF HOURLY CAPACITY FACTOR FOR U.S. COAL-FIRED EGUS – 2008 VS. 2018[8]



An example of such an operation change is presented in **Exhibit 6.** Exhibit 6 shows the hourly gross generation profile of Xcel Energy's 350-MW Harrington unit 1, located in Texas, for the months of December 2008 and December 2018. As mentioned earlier (and in greater detail below), Texas has added a significant amount of wind generation and natural gas-fired generating capacity over the last decade. During December 2008, Harrington 1 remained relatively steady output near its maximum capacity throughout the month, with just eight turndowns, and it never fell below 150 MW.

Conversely, in December 2018, Harrington 1's gross generation output varied significantly. First, the unit was offline five times during the month of December. Second, when online, the unit cycled almost continuously between the maximum and minimum unit output, depending on current load requirements. The data also shows that plant operators turned down the unit to much lower levels than in 2008, with output falling below 150 MW on multiple occasions. Examples like these are much more frequent in 2018 than in previous years and are likely to become more numerous as more wind and solar resources are added to the generation mix.

EXHIBIT 6: XCEL ENERGY'S HARRINGTON UNIT 1 HOURLY GROSS GENERATION DURING DECEMBER[9]



8 Source: EVA Analysis of Environmental Protection Agency (EPA) Continuous Emissions Monitoring System (CEMS) Hourly Data

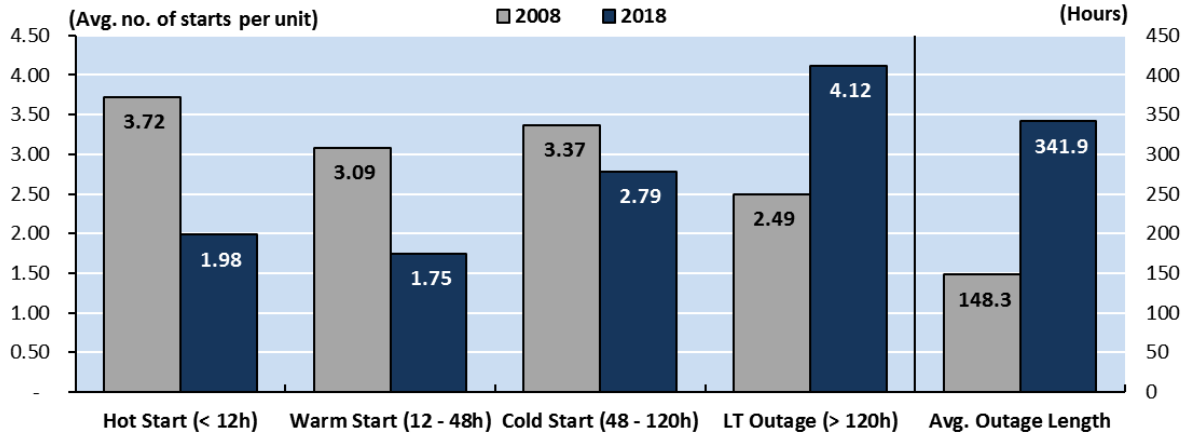
9 Source: EPA CEMS Hourly Data

Operating a coal-fired EGU below its optimal boiler design utilization rate has adverse effects on both the efficiency of the unit and its structural integrity. At lower utilization rates, coal units consume more fuel to produce the same amount of electricity, resulting in both higher fuel costs and emissions of SO_2, NO_x, and CO_2. Additionally, more frequent and faster load changes increase the stress on the boiler equipment and shorten the time between maintenance outages for the unit. The impacts are described in more detail in the next section.

Another metric to consider when assessing the flexibility of coal-fired EGUs and the impacts of unit cycling are its number of hot, warm, and cold starts. Hot starts are typically defined to have very high (700°F to 900°F) boiler and turbine temperatures and occur after 8 to 12 hours offline. Warm starts generally have boiler and turbine temperatures between 250°F and 700°F and occur after the unit has been offline for 12 to 48 hours. Starts at ambient temperatures are considered cold starts after the boiler was offline for 48 to 120 hours.[10] These definitions vary from unit to unit based on design, unit size, and manufacturer.

Generally, the colder the temperature of the boiler and turbine, the higher the startup cost of the unit. **Exhibit 7** shows the comparison between the average number of hot, warm, and cold starts for all U.S. coal-fired EGUs, as well as the average number of long-term outages and the average length of outages between starts in 2008 and 2018. Although the total average amount of starts per unit is similar between 2008 and 2018 (12.67 vs. 10.64 total starts per year respectively), Exhibit 7 clearly shows a shift away from more frequent starts at various temperature levels to longer-term outages (greater than 120 hours, or five days). On average, coal-fired EGUs in 2018 experienced less than four hot and warm starts (starts after being offline for less than 48 hours), compared to almost eight such starts in 2008. Conversely, coal units in 2018 have experienced long-term outages (greater than five days) more frequently, with over four such outages per year compared to just 2.5 per year in 2008. Finally, the average outage length for U.S. coal units in 2018 has more than doubled from less than 150 hours (approximately six days) per outage to over 340 hours per outage (approximately 14 days).

EXHIBIT 7: AVERAGE NUMBER OF STARTS PER COAL-FIRED EGU – 2008 VS. 2018[11]



10 Source: Lefton S A, Besuner P M, Grimsrud G P, Kuntz T A (2010) *Experience in cycling cost analysis of power plants in North America and Europe.*

11 Source: EVA Analysis of EPA CEMS Data

A third metric to consider when analyzing the operational changes the U.S. coal fleet experienced over the previous decade is the rate of change of generation output over a period of time, also known as ramp rates. Ramp rates can vary significantly between plant and fuel types. **Exhibit 8** shows various flexibility capabilities by technology type, according to IEA.

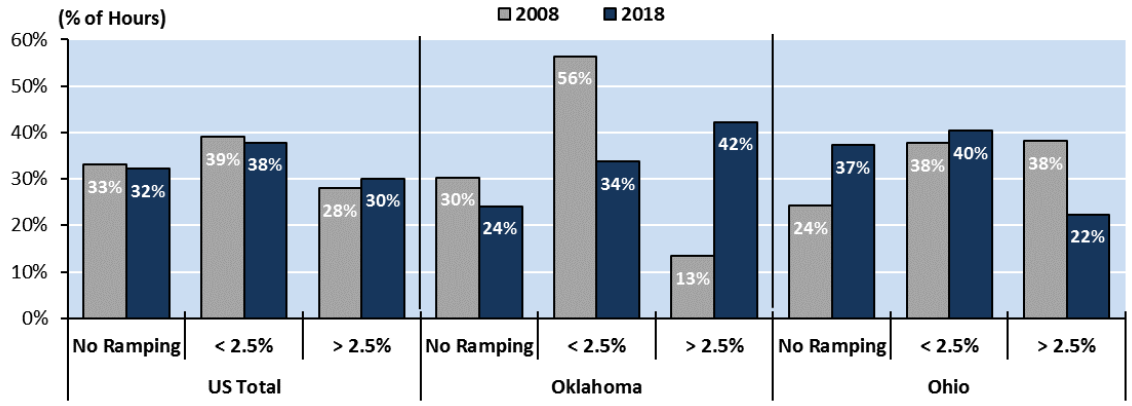
EXHIBIT 8: CAPABILITY OF DIFFERENT POWER GENERATING TECHNOLOGIES TO PROVIDE FLEXIBILITY[12]

Plant Type	Start-up time	Max Change in 30secs, %	Max ramp rate, %/min
Simple Cycle CT	10 - 20 min	20 - 30	20
Combined Cycle CT	30 - 60 min	10 - 20	5 - 10
Coal Plant	1 - 10 h	5 - 10	1 - 5
Nuclear Plant	2 h - 2 d	< 5	1 - 5

Although coal plants are far more flexible than nuclear power plants, they are generally less flexible than their natural gas-fired competition. Simple cycle and combined cycle natural gas-fired combustion turbines (CTs) have much shorter start-up times than coal-fired units as well as faster ramp rates and spinning capabilities. (For this report, ramp rates refer to the hourly change in gross electric output.) The ramp rates listed above are maximum ramp rates that also depend on the unit's specific design characteristics. Frequent ramping of a unit at these maximum ramp rates can significantly shorten the life of the unit before certain parts need to be replaced. The analysis in this report focuses on hourly changes in output for the coal units in 2008 and 2018 and does not make any inference on the maximum ramping capabilities of these units.

Exhibit 9 shows the average distribution of hourly ramp rates (when online) for the U.S. coal fleet in 2008 and 2018 in three categories: no ramping (i.e., no change in output from the previous hour), less than 2.5% change in output, and greater than 2.5% change in gross electric output.

EXHIBIT 9: AVERAGE DISTRIBUTION OF HOURLY RAMP RATES FOR THE U.S. COAL FLEET AND TWO SPECIFIC STATES – 2008 VS. 2018[13]



12 Source: International Energy Agency – Clean Coal Centre (2016) *Levelling the intermittency of renewables with coal.*

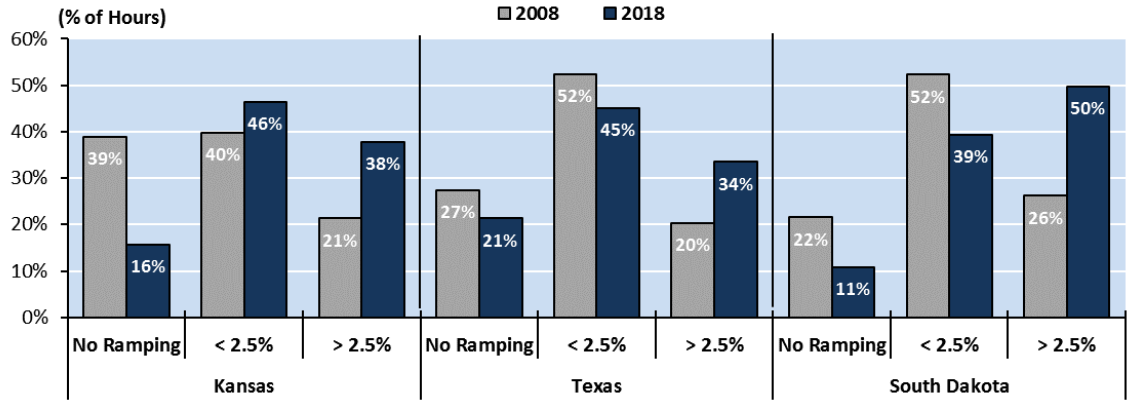
13 Source: EVA Analysis of EPA CEMS Data

As shown in **Exhibit 9,** there is little change in ramp rates for the average coal unit when comparing the ramp rates on a national level between 2008 and 2018. For all three categories, the 2018 values are within two percentage points of its 2008 counterparts, indicating little change on a national level. However, there are significant differences on a regional level.

Between 2008 and 2018, Oklahoma's coal fleet lost more than 30% of generation share, mostly to new wind resources in the state. Since little to no new peaking units have come online in the state since 2008, the responsibility of balancing the possible sudden loss of wind generation fell on the remaining Oklahoma coal units. As a result, Oklahoma's coal units have significantly increased their share of output changes greater than 2.5%, from 13% in 2008 to over 42% in 2018. Conversely, the percentage of ramping at less than 2.5% has fallen tremendously, from 56% in 2008 to 34% in 2018.

As shown in **Exhibit 10,** other states where coal generation was mainly displaced by wind with almost no new peaking capacity have seen similar developments. For example, in Kansas, the number of times an average coal unit in the state ramped up or down at rates greater than 2.5% increased from 21% in 2008 to 36% in 2018.

EXHIBIT 10: AVERAGE DISTRIBUTION OF HOURLY RAMP RATES COAL FLEET IN WIND STATES – 2008 VS. 2018[14]

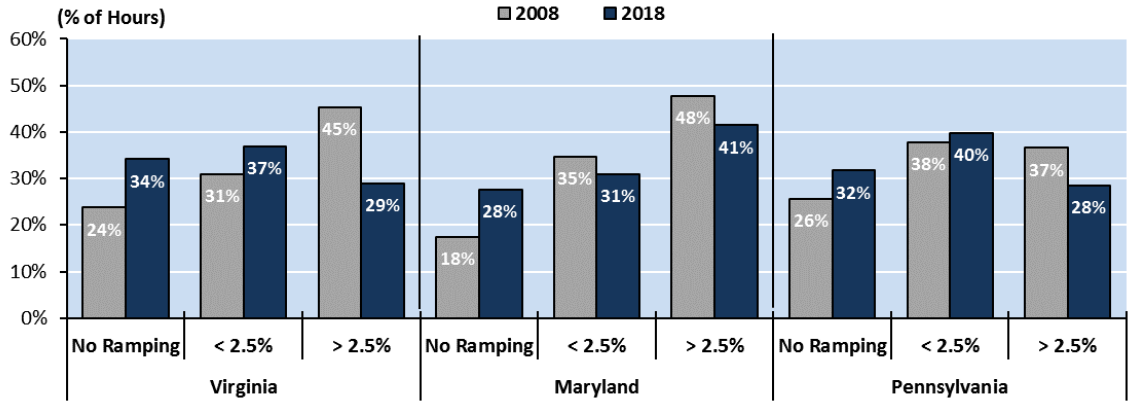


On the other hand, coal units in states where coal has been displaced mainly by new natural gas simple cycle and combined cycle power plants have been subject to less ramping at higher percentages. In Ohio, coal's generation share fell by 38 percentage points between 2008 and 2018, while natural gas's share increased by 33 percentage points over the same period. With cheap natural gas supply in the region, Ohio's new and highly efficient natural gas power plants are more economical to operate than most of the remaining in-state coal fleet. As a result, Ohio natural gas plants are being dispatched ahead of most of the Ohio coal fleet, while also providing flexibility support. Ohio coal plants are mainly called upon during times of high electricity demand to provide additional baseload generation, while the new natural gas plants provide load-following support. As a result, as seen in Exhibit 9, coal's ramp rates above 2.5% have fallen between 2008 and 2018, from 38% to 22%, respectively. Conversely, hours during which coal plants did not ramp at all increased from 24% in 2008 to 37% in 2018.

14 Source: EVA Analysis of EPA CEMS Data

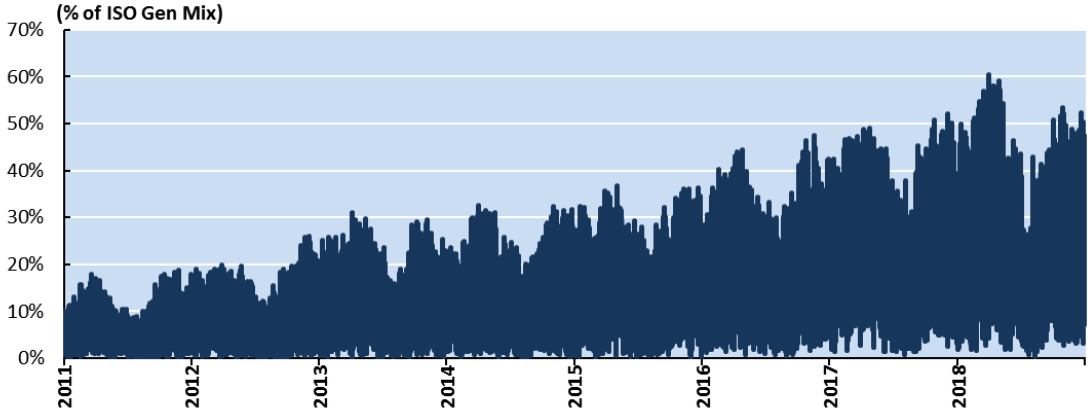
Again, states where electric generation shifted predominantly from coal to natural gas have seen similar developments, as shown in **Exhibit 11.** For example, in Virginia, another state where coal has been displaced mainly by natural gas, the share of ramp rates for coal units greater than 2.5% has fallen since 2008, from 45% to just 29% in 2018.

EXHIBIT 11: AVERAGE DISTRIBUTION OF HOURLY RAMP RATES COAL FLEET IN NATURAL GAS STATES – 2008 VS. 2018[15]



High ramp rate requirements for coal units in states with a significant share of wind generation already will continue to increase as more wind resources are added to the generation mix. **Exhibit 12** shows the hourly wind generation share in the SPP, the ISO for states with some of the highest percentages of wind generation in 2018, including Kansas, Oklahoma, and both of the Dakotas. In 2018, the generation share of wind rose to 60% on March 31 and fell to almost zero on August 8, with fluctuations of more than 9 GWh of generation in six hours on February 17. With coal still accounting for more than two-thirds of fossil fuel generation in SPP, that variation in wind generation is being balanced mostly by coal-fired EGUs.

EXHIBIT 12: HOURLY WIND GENERATION SHARE IN SPP – 2011 TO 2018[16]

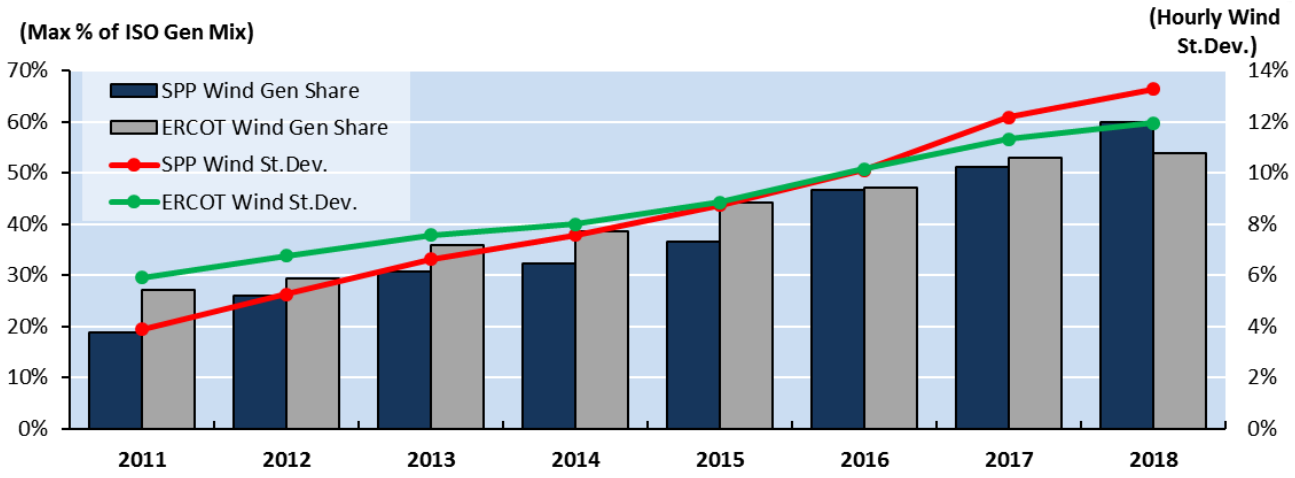


15 Source: EVA Analysis of EPA CEMS Data

16 Source: Southwest Power Pool (SPP) Hourly Generation Mix Data

As more wind generation is being added to the electric power system, utilities and ISOs, such as ERCOT and SPP, have to balance more considerable amounts of the variable generation with dispatchable generating units such as coal and natural gas. **Exhibit 13** shows the trend since 2011 in annual wind generation share for ERCOT and SPP, as well as the standard deviation for hourly wind generation for the two ISOs. Although wind developers and ISOs attempt to diversify wind farms locationally to minimize the variability of wind output, wind variability has continued to increase significantly in both ISOs. In 2011, when hourly wind output peaked at just 20% of SPP's generation, the standard deviation for the hourly generation mix share from wind was below 4%. In 2018, however, when the peak hourly generation share of wind increased to 60%, the standard deviation more than tripled to over 13%. As more wind is added to the ISO's generation mix, flexibility from dispatchable resources such as coal and natural gas has become more critical.

EXHIBIT 13: MAX HOURLY WIND GENERATION SHARE & STANDARD DEVIATION FOR ERCOT & SPP ISO – 2011 TO 2018[17]

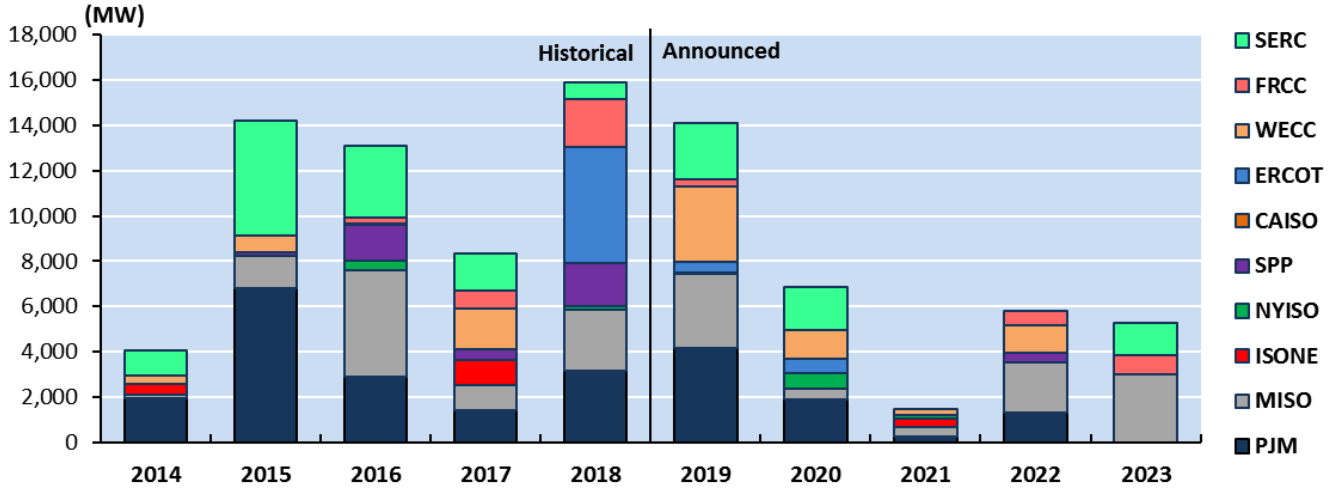


Despite the increased importance of flexible and dispatchable generation to balance the variability of a growing renewable fleet, more and more coal plants are being retired in power markets with an ever-increasing share of renewable generation. **Exhibit 14** shows historical and announced coal retirements by power market. In 2018, a record 16 GW of coal-fired generation retired, more than in any other previous year. 2019 follows close behind with another 14 GW of coal capacity either already retired or scheduled to retire. More than 30 GW of additional coal capacity have already retired or are announced to retire by 2023 in MISO, ERCOT, and SPP alone, the three power markets with the highest share of wind generation in 2018. Unlike the massive amounts of coal retirements in 2015 and 2016 due to the compliance deadline for the EPA Mercury and Air Toxics Standard (MATS), these coal retirements are mainly due to reduced revenues as a result of lower utilization rates. The next section discusses the structural and financial implications of increased cycling of coal-fired power plants and

17 Source: EVA Analysis of SPP and ERCOT Hourly Generation Mix Data

how coal plant owners are, or are not, currently compensated for providing much needed operational flexibility to the grid.

EXHIBIT 14: HISTORICAL COAL RETIREMENTS BY POWER MARKET – 2008 TO 2018[18]



18 Source: EVA Power Plant Tracking System Database

The Costs and Implications of Coal Plant Cycling

As described in the previous section, coal-fired power plants are operating less frequently in baseload operation, where they provide a constant level of electric output with minimal variation. Instead, they are asked to provide more operational flexibility in response to higher shares of intermittent generating resources, such as wind and solar entering the market.

There are two main types of coal plant cycling practices to facilitate changes in output, as mentioned previously: completely shutting down the coal unit or changing its electric output to follow load. As both types imply a diversion from designed operating practices, operating costs for coal-fired power plants are expected to increase (substantially in some cases) as revenue from decreased energy market payments falls. These operational changes and other factors associated with more flexible operation can have the following effects on coal-fired EGUs:

- Increased wear-and-tear on high-temperature and high-pressure plant components and associated costs
- Increased wear-and-tear on balance-of-plant components and related costs
- Shorter periods between maintenance time but more prolonged outages
- Decreased thermal efficiency at high turndown levels
- Increased fuel costs due to more frequent and inefficient unit starts, which require start-up fuel
- Difficulties in maintaining optimal steam chemistry leading to accelerated corrosion
- Potential for catalyst fouling on NO_x control equipment
- Long-term loss of critical equipment life
- Efficiency losses during startup through synchronization and loading to zero load
- Increased risk of human error in plant operations

Exhibit 15 shows the typical costs for a medium-sized coal-fired power plant during various types of operation, based on previous studies analyzing the financial implications of the increased wear-and-tear and associated maintenance and capital costs listed above.

EXHIBIT 15: TYPICAL STARTUP AND CYCLING COSTS FOR A MEDIUM-SIZED COAL-FIRED POWER PLANT ($2019)[19]

Type of Start	Cost category	Cost estimates ($/MW)		
		Expected	Low	High
Hot Start (1–23 h offline)	Maintenance and capital	$ 128	$ 102	$ 162
	Forced outage	$ 60	$ 48	$ 76
	Start-up fuel	$ 20	$ 14	$ 30
	Auxiliary power	$ 11	$ 8	$ 13
	Efficiency loss from low and variable load operation	$ 5	$ 4	$ 8
	Water chemistry cost and support	$ 1	$ 1	$ 2
	Total cycling cost	**$ 225**	**$ 178**	**$ 291**
Warm Start (24 - 120 h offline)	Maintenance and capital	$ 137	$ 109	$ 170
	Forced outage	$ 65	$ 51	$ 80
	Start-up fuel	$ 43	$ 30	$ 57
	Auxiliary power	$ 23	$ 18	$ 28
	Efficiency loss from low and variable load operation	$ 6	$ 5	$ 9
	Water chemistry cost and support	$ 6	$ 4	$ 9
	Total cycling cost	**$ 277**	**$ 217**	**$ 351**
Cold Start (> 120 h offline)	Maintenance and capital	$ 205	$ 162	$ 255
	Forced outage	$ 96	$ 76	$ 120
	Start-up fuel	$ 64	$ 45	$ 24
	Auxiliary power	$ 29	$ 23	$ 36
	Efficiency loss from low and variable load operation	$ 6	$ 5	$ 10
	Water chemistry cost and support	$ 17	$ 13	$ 21
	Total cycling cost	**$ 417**	**$ 325**	**$ 465**
Load follow down to 36% of Capacity	Maintenance and capital	$ 20	$ 12	$ 31
	Forced outage	$ 9	$ 6	$ 15
	Efficiency loss from low and variable load operation	$ 1	$ 1	$ 2
	Mill cycle gas	$ 2	$ 19	$ 50
	Total cycling cost	**$ 32**	**$ 19**	**$ 50**

As shown in **Exhibit 15,** expected costs for cold starts can be almost double the startup cost for a hot start when the remaining temperature in the boiler and turbine system are still significantly higher. However, even hot starts can range from $89,000 to $145,500 per start for a 500 MW coal-fired EGU. These costs can also vary significantly between coal units based on differences in boiler size and design (subcritical vs. supercritical). The highest cost

19 Source: Lefton S A, Hilleman D (2011). *Make your plant ready for cycling operations.* http://www.powermag.com/make-your-plant-ready-for-cycling-operations/

category for all four operation types above is "maintenance and capital." According to a previous study from the National Renewable Energy Laboratory (NREL), there is a trade-off between high capital and maintenance costs and corresponding lower equipment-forced outage rates (EFORd).

According to a study by the Electric Power Research Institute (EPRI)[20], some of the **damage mechanisms** that occur due to increased load-following and on/off operations include:

- **Thermal fatigue.** This phenomenon, caused by frequent changes in equipment temperature, can produce cracking in thick-walled components, especially castings such as turbine valves and casings. Also affected are boiler superheater and reheater headers, where ligament cracking is commonly seen between tube stubs. These headers are expensive, thick-walled vessels operating under high steam pressure, making this damage of particular concern to plant owners.

- **Thermal expansion.** Several systems in a coal plant consist of components that undergo high thermal growth relative to surrounding components. The most notable example of this phenomenon is the enormous movement of boiler structures relative to the cooler support framework. These support ties are designed to accommodate growth, but are subject to accelerated life consumption if the frequency of thermal cycling increases.

- **Corrosion-related Issues.** Two-shifting, or any other operation that challenges the ability of a plant to maintain water chemistry, can lead to increased corrosion and accelerated component failure. Increased levels of dissolved oxygen in feedwater can be the result of condenser leaks, aggravated by more frequent shutdowns.

- **Fireside corrosion.** Load cycling and relatively quick ramp rates under staged conditions will hurt both fireside corrosion and circumferential cracking.

- **Rotor bore cracking.** When subjected to transients in the temperature of the admitted steam, the high-pressure and intermediate-pressure steam turbine rotors can suffer thermo-mechanical stress excursions, resulting in low-cycle fatigue damage. This damage can result either from introducing hot steam to a relatively cold rotor exterior, or the opposite.

The more accurately costs to repair or replace the issues described above can be predicted and included in the current unit dispatch operation methodology, the lower the risk for a particular coal-fired EGU to experience an unexpected equipment failure and unit outage, and miss out on potentially significant energy revenues.

Numerous studies have explored how to mitigate flexible operation damage. Some of the suggested **mitigation strategies** to reduce the damage and associated costs extensive cycling has on coal plants include:

- **Efficiency improvements.** One option for mitigating the effects of flexible operation is for plants to implement system modifications that recover plant efficiency lost to continuous cycling operation. Mitigation examples

20 Source: Hesler S (2011) *Mitigating the effects of flexible operation on coal-fired power plants.* http://www.powermag.com/mitigating-the-effects-of-flexible-operation-on-coal-fired-powerplants/

include: sliding pressure operation, variable-speed drives for the primary cycle and auxiliary equipment, and changes to boiler draft control schemes and operating philosophy. However, many plants today do not have sufficient capital, whether internally or through the investment community, available to undertake these major system modifications.

- **Establishing and following cycle chemistry guidelines for flexible operations.** An area of particular concern for plants under cycling duty is following appropriate cycle chemistry guideline limits during plant startup, shutdown, and layup. Proper protection of the entire steam circuit (boiler, piping, feedwater, and turbine) is critical during these modes of flexible operation. Correct layup procedures, combined with appropriate chemical treatment during shutdown and startup, will significantly reduce corrosion and deposits in the steam cycle equipment, including the boiler, steam-touched tubing, and the turbine.

- **Accurate damage estimation.** Estimates can be made of damage costs per start to inform the plant's trading position. Cost estimates are based on increased routine maintenance costs, damage to major components, and estimated cost of consumables per start.

- **Flexible operation studies.** These studies reduce component damage through procedure optimization and design modification. Included in the reviews are: an initial appraisal of plant-specific risk areas, installation of additional instrumentation, flexible operation trials, assessment of thermal transients, changes to operating procedures and design to address issues identified, repeat tests to confirm success, and detailed stress analysis to inform strategy going forward.

- **Operator coaching.** Simplified damage algorithms for creep and fatigue are also developed for operator coaching. Plant data for critical components are screened to identify and understand the most damaging operational conditions. Operators can then seek to minimize the extent of such conditions during future unit starts. Proper operator training can reduce the risk of human error during increased coal plant cycling operations.

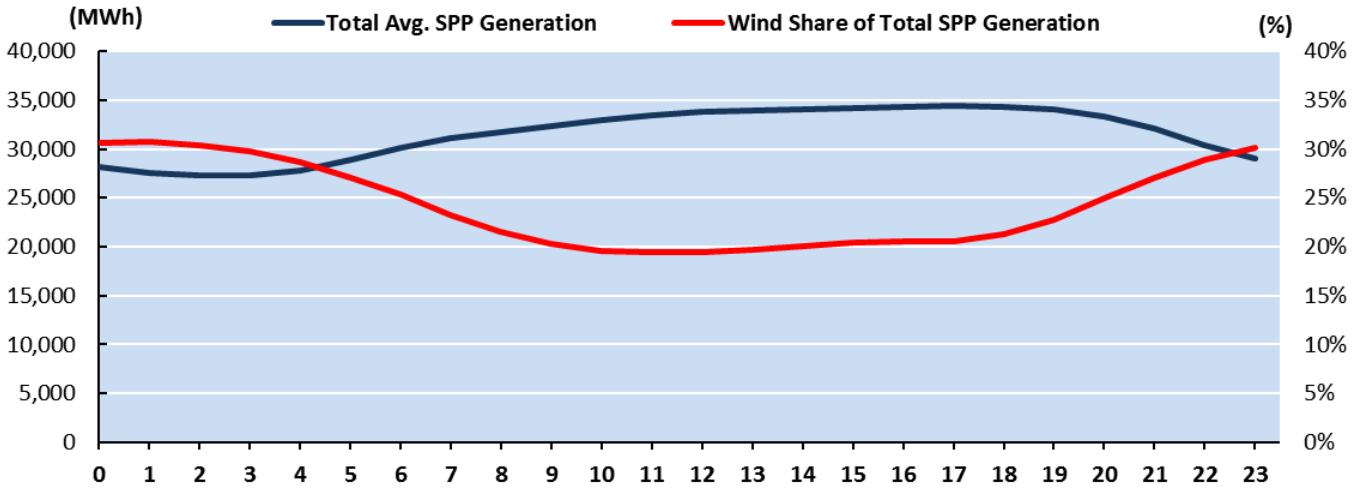
Other areas to minimize coal plant cycling costs, outside the control of coal plant owners, include increased deployment of energy storage and demand-side management resources to shift some of the renewable generation from wind and solar to peak demand hours or reduce the demand fluctuations over the course of the day. A more drastic approach is to curtail wind and solar generation during times of high generation or low demand to minimize the requirement for fossil fuel plant cycling.

Current Financial Compensation Practices for Plant Flexibility Operation

The previous section described various mitigation strategies to counteract the increased maintenance and capital costs due to increased coal plant cycling and shutdowns/startups. Most of these mitigation strategies require significant amounts of additional capital investments by coal plant owners. Recent market developments described previously, including increased renewable generation from wind and solar and low natural gas prices due to the shale gas revolution, have eroded the revenue stream of coal plants significantly. Still, maintaining a flexible baseload fleet is vital to complement the variability of wind generation and keep electricity reliable and affordable, especially during times when new natural gas power plants face additional regulatory hurdles.

One issue with wind generation in SPP is shown in **Exhibit 16.** Exhibit 16 shows the average hourly total generation for SPP during a 24-hour cycle in 2018 along with the wind generation share during those same hours. In 2018, wind supplied over 30% of the generation between 11 pm and 3 am, while dropping to just 20% between 10 am and 5 pm. Conversely, demand for electricity in SPP reaches its low point at 3 am and starts to climb throughout the day, before beginning to decline again around 6 pm. Therefore, during peak electricity demand times, wind generation in SPP is generally at its lowest, requiring other generating resources such as coal and natural gas to increase generation accordingly.

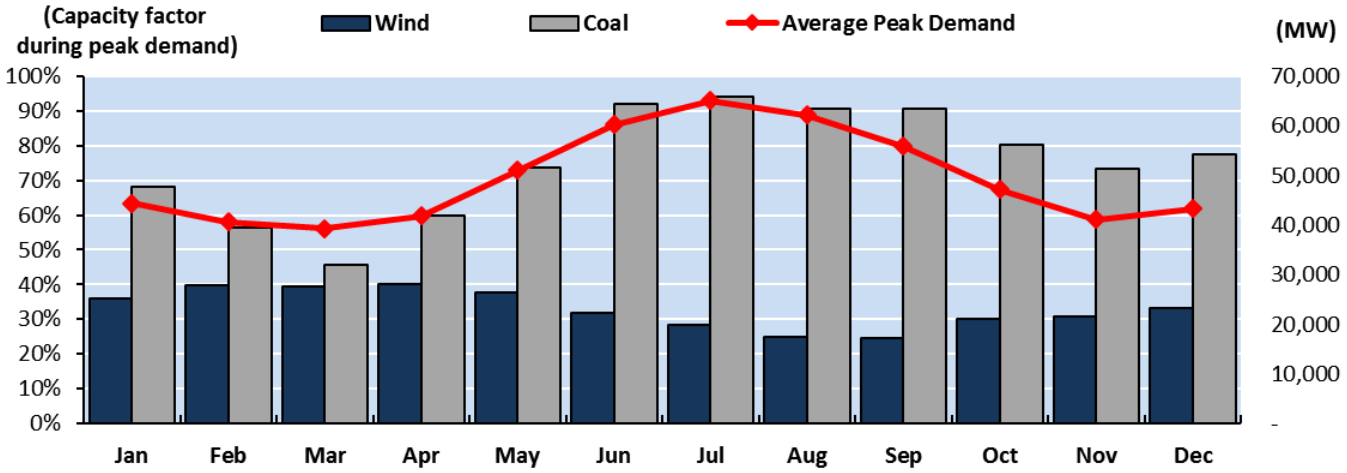
EXHIBIT 16: 2018 AVERAGE HOURLY SPP GENERATION VS. WIND GENERATION SHARE[21]



Additionally, wind generation varies significantly from month to month. Exhibit 17 shows the average capacity factors for both coal and wind and during peak demand hours by month for ERCOT for the years 2016 through 2018. Wind generation tends to achieve its highest capacity factors during the spring and fall seasons while being at its lowest during the hot summer months. On the other hand, demand for electricity reaches its peak during the hot summer months when the use of air conditioning drives up demand. Again, due to the seasonality of wind, additional generating resources are needed to increase generation to ensure reliable electricity delivery.

21 Source: SPP Hourly Generation Mix Data

EXHIBIT 17: AVERAGE CAPACITY FACTOR OF WIND AND COAL GENERATION DURING PEAK DEMAND HOURS IN ERCOT BY MONTH – 2016 TO 2018[22]



Historically, as shown in **Exhibit 17,** coal-fired EGUs operated at full capacity during high demand seasons, such as summer and winter, while frequently cycling between minimum load and full load during the shoulder months when online. During shoulder months, power prices during off-peak hours (late night to early morning hours) would sometimes drop below the coal unit's operating costs, therefore losing money during those hours. However, coal unit operators would accept the overnight losses to be available during peak demand hours, subsequently having the opportunity to recoup lost revenue.

The shale gas revolution and the increased development of renewable generating resources have changed this equation dramatically. As a review, power prices in deregulated power markets are set by the EGU that provides the marginal MWh to meet electricity demand at that time. As the dispatch cost for wind is essentially zero, the increased share of wind generation has caused off-peak power prices to decline in recent years. Additionally, on-peak power prices have fallen at even higher rates, as natural gas prices have plummeted, reducing the dispatch costs for combustion turbines which historically used to be the marginal resources and set the on-peak power prices. In some regions, dispatch costs for combustion turbines and combined cycle power plants have dropped well below coal-fired power plants, leaving an increasing number of coal plants "out-of-the-money."

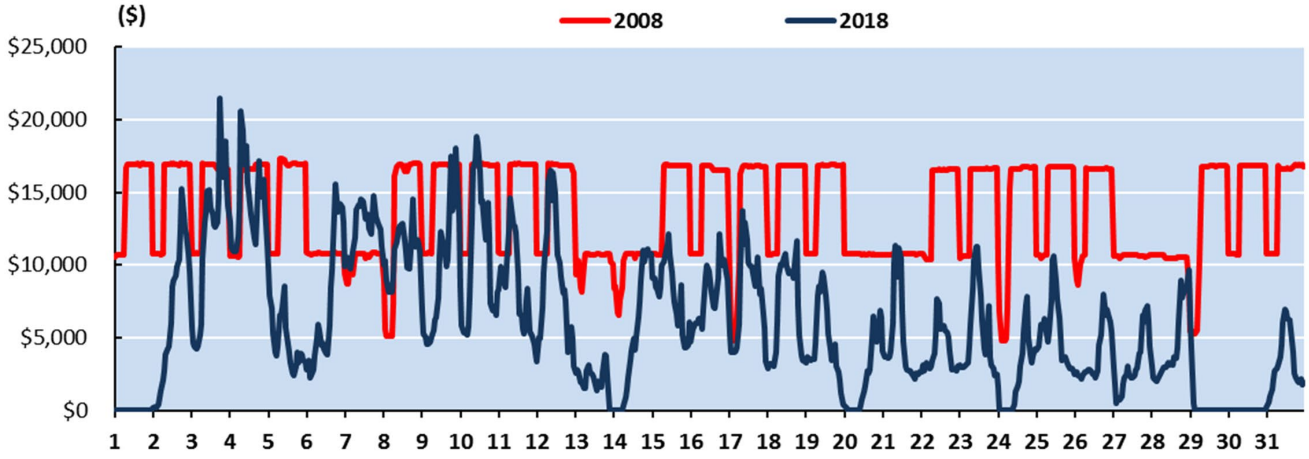
As a result, coal plants frequently find themselves in a vicious cycle. Due to the low revenue expectation during on-peak hours and to minimize losses during off-peak hours, coal plants more often shut down operations for longer periods and only return to service when more extended periods of profitability are expected. However, the longer coal-fired EGUs remain offline, the more expensive it becomes to return them to service. In fact, cold starts are often more than three times more expensive than hot starts, increasing the capital and maintenance costs associated with operating the unit. On the other hand, lower revenues due to lower wholesale power prices and lower plant utilization rates have reduced the working capital for many coal plant operators, therefore limiting the amount of available capital to spend on maintenance or to make significant improvements to reduce the overall cycling cost of the unit.

22 Source: ERCOT Hourly Generation Mix Data

Consequently, the combination of falling on-peak and off-peak power prices and increased cycling operations have significantly eroded the economic viability of many coal-fired power plants across the country, even though they can provide essential reliability and flexibility services.

Xcel's Harrington 1 coal-fired unit in Texas, the example from earlier, provides a useful case study of this issue. In December 2008, the EGU operated at a capacity factor of 94.7%, had zero shutdowns over the course of the month, and its average hourly ramp rate was 1.1%. In December 2018, these numbers were drastically different. Harrington 1's capacity factor dropped to 57.1%. It experienced five different startups (three hot starts and two warm starts), and its average hourly ramp rate increased to 4.9%. Additionally, on-peak and off-peak power prices for SPP-South, where Harrington is located, dropped 38% and 23% between December 2008 and 2018, respectively. **Exhibit 18** shows Harrington's estimated hourly energy revenue for the month of December in 2008 and 2018.

EXHIBIT 18: ESTIMATED ENERGY REVENUE FOR XCEL ENERGY'S HARRINGTON 1 COAL UNIT – DECEMBER 2008 & 2018[23]



As shown in **Exhibit 6,** Harrington 1 operated at full capacity almost all of December 2008 and generated over $10 million in energy revenue as a result. In December 2018, however, as power prices collapsed and Harrington 1 operated at much lower utilization rates, its energy revenue fell to $4.5 million. Including the additional costs of approximately $500,000 for the two warm starts and three hot starts, Harrington 1 generated more than $6 million less in net revenue in December 2018 compared to 2008. This does not include any additional O&M requirements to offset the greater stress on plant equipment due to the more frequent cycling operations.

As is recognized by market participants in both regulated and deregulated power markets, it is of utmost importance to retain a significant amount of electric generating capacity above peak electricity demand to account for unexpected losses in variable energy generation from wind and solar, unscheduled fossil plant outages, and under-forecasts of load. This amount of excess capacity is referred to as the reserve margin. Because wind resources tend to be at lower generation levels during peak demand hours as described previously, wind resources are rated at lower capacity

23 Source: S&P Global Platts Megawatt Daily Power Price Data

values than other resources. While some power markets such as PJM provide capacity payments to generating resources to provide capacity when needed, the two markets with the highest share of intermittent renewable generation, SPP and ERCOT, do not have capacity markets. Both markets are considered energy-only markets (although SPP does have a resource adequacy requirement tariff).

Both ERCOT and SPP acknowledged in their latest State of the Market Reports[24] that it is in the best interest for the market to develop compensation mechanisms or products to pay for capacity to cover uncertainties, such as the loss of the significant amount of generation during high demand times, as was the case in ERCOT this summer. The independent market monitor for ERCOT acknowledged that in 2018, coal units in ERCOT received just enough revenue from energy and ancillary services to cover operating costs.[25]

The other two major independent power markets with significant coal generation, PJM and MISO, are also in the process of developing new market mechanisms to better support and compensate the coal plants in their markets for the reliability and flexibility they provide. MISO, for example, is currently exploring the introduction of a so-called multi-day operating margin forecast. The forecast provides key power market metrics such as expected renewable generation, forecasted load, and scheduled plant outages for the next seven days to allow plant operators to make commitment decisions well ahead of the day-ahead market auction. PJM, on the other hand, tries to minimize the financial losses coal plants incur overnight. As mentioned previously, many coal plants cannot turn off completely overnight as they have to be available during peak demand hours in the morning. However, with the rise in renewable generation and drop in natural gas prices, off-peak power prices during the late night/early morning hours have dropped well below the operating costs of many of these coal plants, forcing them to incur huge losses these plants are struggling to recoup during the day. PJM is working on a pricing tool that allows certain baseload power plants to receive higher prices during off-peak hours to ensure they provide flexible and reliable generation during the day.

Regulated Utilities

Regulatory mechanisms minimize the financial exposure regulated utilities face compared to their merchant counterparts. However, they do experience their own unique struggles. Regulated utilities generally have two options to recover the costs for operating their generating fleet.

First, every few years, regulated utilities forecast their expenditures for maintaining affordable and reliable electricity supply, and request an electric rate adjustment through a "rate case" to recoup their expected capital expenditures and guarantee a set rate of return. However, there is generally no true-up to previous rate cases. If a utility greatly underestimated the costs to operate its generation fleet during its last rate case, the utility incurs these costs with no possibility to recoup those losses. Regulated utilities do use past projections versus performance measures to inform their next rate adjustment.

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24 Southwest Power Pool. "State of the Market 2018" (May 2019) https://www.spp.org/documents/59861/2018%20annual%20state%20of%20the%20market%20report.pdf

25 Potomac Economics. "State of the Market Report for ERCOT Electricity Markets" (June 2019) https://www.potomaceconomics.com/wp-content/uploads/2019/06/2018-State-of-the-Market-Report.pdf

The second option for utilities to recoup their investments in their generating fleet is through short-term adjustments. Based on the state, these adjustments vary in name and frequency. For example, in Alabama, regulated utilities can recover increased fuel or purchased power expenditures through the Energy Cost Recovery Rider. In other states, such as Wyoming, utilities are also allowed to recover some of their increased O&M costs through annual adjustment riders. However, in states where capital expenditures for increased O&M caused by operational changes at coal-fired power plants discussed throughout this report can only be recovered through projected going-forward costs as part of a rate case, some utilities have likely incurred some unexpected losses over the last decade.

As the example in Texas this summer has shown, sufficient backup flexible capacity is needed to ensure reliable electricity supply during peak demand times, coupled with a higher-than-expected loss of variable generation from wind or solar. Without any other market mechanisms incentivizing new capacity entry into the market, keeping existing fossil generation from retiring becomes paramount. Even in regulated states, continued operation of and investment in existing coal-fired power plants can oftentimes be the more economical choice than building a new natural gas plant. Besides the technology options discussed in this report to make existing coal plants more flexible and efficient, new technologies begin to emerge and provide viable alternatives to natural gas peaking resources in the near future. According to a recent report from Bloomberg New Energy Finance, lithium-ion battery prices have dropped faster than projected, from over $1,100/kWh in 2010 to $156/kWh in 2019.[26] As the industry focuses on bringing new energy storage and flexible generation to commercial operation, utilities focus on maintaining the existing fleet of fossil resources to bridge that timing gap.

Regulators in California are now pursuing a similar strategy. In order to achieve its aggressive GHG emission reduction goal, California required utilities to invest in new non-hydro renewable generation heavily, mainly solar and, to a lesser extent, wind, while also banning new natural gas generation from entering the market. As older fossil plants have retired over the last few years due to the loss of energy revenue and increased operating costs, California's reserve margin began to shrink, and the risk of a potential loss of load increased. Now, regulators in California required existing natural gas generation to continue operating and provide much-needed backup flexible generation while new non-GHG emitting energy storage resources such as battery storage enter the market.[27]

26 BNEF. "Battery Pack Prices Fall As Market Ramps Up With Market Average At $156/kWh In 2019" (December 2019) https://about.bnef.com/blog/battery-pack-prices-fall-as-market-ramps-up-with-market-average-at-156-kwh-in-2019/?sf113554299=1

27 http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M312/K522/312522263.PDF

Conclusion

In summary, it is worth highlighting the following points:

- Coal plant operations have changed dramatically over the last decade, forced by changing market dynamics due to low natural gas prices and increased generation from intermittent renewable energy resources such as wind and solar.

- While not originally designed to be load-following, many coal plants are capable of providing flexible generation at efficient and cost-effective levels to complement increased renewable generation. Additionally, technology improvements exist to increase the efficiency and flexibility of existing coal plants that are oftentimes more economical than building new generation capacity.

- However, the current market and regulatory mechanisms are not sufficient to offset some or all of the increased one-time and ongoing costs for coal-fired power plant operators to support this change in plant operations. Power markets and regulatory commissions provide different options to help mitigate the issue and are focusing on developing new mechanisms or making changes to existing ones.

- Recent examples in Texas and California have shown the necessity of maintaining existing generating resources to provide much-needed flexible and reliable generation while new energy storage technologies are being developed and deployed.

Appendix

EXHIBIT 19: GENERATION MIX BY STATE – 2008 VS. 2018

	2008							2018						
	Coal	Natural Gas & Oil	Nuclear	Hydro	Wind	Solar	Other	Coal	Natural Gas & Oil	Nuclear	Hydro	Wind	Solar	Other
US Total	**50%**	**21%**	**20%**	**6%**	**1%**	**0%**	**1%**	**28%**	**35%**	**20%**	**7%**	**7%**	**2%**	**1%**
Alaska	6%	76%	0%	18%	0%	0%	0%	9%	64%	0%	24%	2%	0%	0%
Alabama	53%	15%	28%	4%	0%	0%	0%	23%	41%	28%	8%	0%	0%	0%
Arkansas	49%	15%	27%	9%	0%	0%	0%	46%	29%	19%	5%	0%	0%	0%
Arizona	37%	33%	25%	6%	0%	0%	0%	27%	33%	28%	6%	1%	5%	0%
California	1%	56%	17%	13%	3%	0%	9%	0%	44%	10%	14%	8%	15%	9%
Colorado	65%	25%	0%	3%	6%	0%	0%	47%	30%	0%	3%	18%	2%	0%
Connecticut	15%	28%	51%	2%	0%	0%	5%	1%	50%	44%	1%	0%	0%	3%
District Of Columbia	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Delaware	76%	22%	0%	0%	0%	0%	2%	6%	92%	0%	0%	0%	1%	1%
Florida	30%	53%	15%	0%	0%	0%	2%	13%	72%	12%	0%	0%	1%	2%
Georgia	64%	10%	24%	1%	0%	0%	0%	26%	42%	28%	2%	0%	2%	1%
Hawaii	15%	79%	0%	0%	2%	0%	3%	14%	71%	0%	1%	6%	2%	7%
Iowa	76%	4%	10%	2%	8%	0%	0%	44%	12%	8%	2%	35%	0%	0%
Idaho	0%	15%	0%	82%	2%	0%	1%	0%	18%	0%	62%	15%	3%	1%
Illinois	48%	2%	48%	0%	1%	0%	0%	31%	8%	53%	0%	7%	0%	0%
Indiana	97%	3%	0%	0%	0%	0%	0%	72%	22%	0%	0%	5%	0%	0%
Kansas	73%	5%	18%	0%	4%	0%	0%	39%	7%	17%	0%	36%	0%	0%
Kentucky	94%	4%	0%	2%	0%	0%	0%	75%	18%	0%	6%	0%	0%	0%
Louisiana	36%	39%	23%	2%	0%	0%	0%	17%	58%	24%	1%	0%	0%	0%
Massachusetts	25%	55%	14%	1%	0%	0%	5%	0%	68%	16%	2%	1%	5%	7%
Maryland	58%	5%	31%	4%	0%	0%	1%	23%	31%	35%	7%	1%	1%	2%
Maine	1%	47%	0%	32%	1%	0%	18%	1%	22%	0%	35%	26%	0%	17%
Michigan	61%	9%	28%	0%	0%	0%	2%	38%	28%	27%	1%	5%	0%	2%
Minnesota	58%	6%	25%	1%	8%	0%	2%	37%	15%	24%	2%	18%	2%	2%
Missouri	81%	6%	10%	3%	0%	0%	0%	73%	8%	13%	2%	4%	0%	0%
Mississippi	36%	44%	20%	0%	0%	0%	0%	9%	80%	11%	0%	0%	1%	0%
Montana	62%	2%	0%	34%	2%	0%	0%	48%	3%	0%	39%	8%	0%	1%
North Carolina	61%	4%	32%	2%	0%	0%	0%	24%	34%	32%	4%	0%	5%	1%
North Dakota	91%	0%	0%	4%	5%	0%	0%	66%	2%	0%	6%	26%	0%	0%
Nebraska	66%	2%	29%	1%	1%	0%	0%	63%	3%	15%	4%	14%	0%	0%
New Hampshire	15%	31%	41%	7%	0%	0%	5%	4%	18%	58%	9%	2%	0%	9%
New Jersey	14%	33%	51%	0%	0%	0%	2%	2%	52%	43%	0%	0%	2%	2%
New Mexico	74%	21%	0%	1%	4%	0%	0%	41%	35%	0%	1%	19%	4%	0%
Nevada	22%	68%	0%	5%	0%	0%	4%	6%	67%	0%	5%	1%	12%	9%
New York	13%	34%	31%	19%	1%	0%	2%	1%	38%	33%	23%	3%	0%	2%
Ohio	86%	3%	11%	0%	0%	0%	0%	47%	35%	15%	0%	1%	0%	0%
Oklahoma	48%	44%	0%	5%	3%	0%	0%	17%	48%	0%	3%	32%	0%	0%
Oregon	7%	29%	0%	59%	4%	0%	1%	2%	27%	0%	57%	11%	1%	1%
Pennsylvania	53%	9%	36%	1%	0%	0%	1%	21%	36%	39%	1%	2%	0%	1%
Rhode Island	0%	98%	0%	0%	0%	0%	2%	0%	93%	0%	0%	2%	1%	3%
South Carolina	42%	6%	52%	0%	0%	0%	0%	20%	23%	54%	2%	0%	1%	1%
South Dakota	52%	4%	0%	42%	2%	0%	0%	21%	9%	0%	46%	24%	0%	0%
Tennessee	63%	1%	31%	6%	0%	0%	0%	26%	16%	46%	12%	0%	0%	0%
Texas	40%	44%	11%	0%	4%	0%	0%	26%	46%	10%	0%	18%	1%	0%
Utah	82%	16%	0%	1%	0%	0%	1%	66%	21%	0%	3%	2%	6%	2%
Virginia	44%	15%	40%	0%	0%	0%	1%	10%	54%	32%	0%	0%	1%	3%
Vermont	0%	0%	72%	22%	0%	0%	6%	0%	0%	0%	59%	17%	6%	18%
Washington	8%	9%	8%	71%	3%	0%	1%	5%	9%	8%	71%	6%	0%	0%
Wisconsin	66%	9%	20%	2%	1%	0%	1%	50%	26%	15%	4%	3%	0%	1%
West Virginia	98%	0%	0%	1%	0%	0%	0%	94%	2%	0%	2%	3%	0%	0%
Wyoming	96%	0%	0%	2%	2%	0%	0%	87%	1%	0%	2%	9%	0%	0%

EXHIBIT 20: AVERAGE UTILIZATION DISTRIBUTION BY STATE – 2008 VS. 2018

	2008						2018					
	Offline	< 40%	40 - 60%	60 - 80%	> 80%	Avg. Turndown	Offline	< 40%	40 - 60%	60 - 80%	> 80%	Avg. Turndown
US Total	**17%**	**3%**	**9%**	**15%**	**55%**	**52%**	**32%**	**6%**	**12%**	**14%**	**37%**	**43%**
Alabama	13%	3%	11%	16%	58%	50%	34%	9%	17%	11%	29%	43%
Arkansas	15%	2%	5%	9%	70%	53%	20%	4%	9%	12%	55%	43%
Arizona	7%	1%	2%	9%	81%	70%	15%	8%	13%	29%	36%	44%
Colorado	11%	1%	5%	12%	71%	63%	20%	0%	12%	27%	41%	57%
Connecticut	7%	6%	3%	3%	81%	36%	85%	4%	1%	2%	8%	12%
Delaware	18%	13%	15%	19%	34%	35%	85%	2%	7%	2%	4%	10%
Florida	19%	3%	12%	15%	52%	52%	33%	11%	14%	14%	28%	35%
Georgia	11%	5%	23%	16%	44%	46%	54%	8%	13%	9%	15%	34%
Iowa	21%	3%	12%	24%	40%	50%	30%	7%	12%	10%	42%	35%
Illinois	14%	3%	10%	15%	57%	53%	28%	5%	13%	16%	39%	46%
Indiana	18%	3%	8%	13%	59%	52%	30%	4%	12%	13%	41%	46%
Kansas	12%	1%	6%	19%	62%	61%	29%	9%	11%	14%	38%	41%
Kentucky	13%	3%	8%	16%	60%	52%	24%	4%	12%	17%	43%	43%
Louisiana	13%	2%	3%	8%	75%	57%	28%	6%	13%	19%	33%	43%
Maryland	22%	8%	13%	18%	39%	40%	71%	8%	6%	5%	11%	19%
Michigan	16%	3%	11%	22%	48%	51%	35%	3%	15%	20%	26%	43%
Minnesota	21%	3%	9%	20%	47%	52%	20%	2%	21%	16%	42%	49%
Missouri	14%	2%	5%	14%	66%	58%	21%	2%	10%	13%	54%	51%
Mississippi	15%	2%	5%	7%	71%	53%	49%	29%	17%	4%	1%	35%
Montana	12%	2%	4%	11%	72%	55%	30%	4%	4%	19%	42%	46%
North Carolina	31%	7%	13%	11%	38%	39%	54%	12%	9%	7%	19%	33%
North Dakota	10%	0%	1%	8%	80%	75%	11%	0%	7%	13%	67%	69%
Nebraska	9%	1%	11%	33%	47%	56%	16%	5%	20%	14%	44%	42%
New Hampshire	14%	2%	2%	6%	77%	73%	68%	1%	2%	5%	23%	47%
New Jersey	48%	6%	9%	15%	22%	40%	98%	0%	1%	0%	1%	7%
New Mexico	15%	1%	2%	4%	78%	71%	26%	4%	9%	17%	45%	56%
Nevada	19%	2%	3%	7%	69%	57%	36%	19%	10%	13%	22%	38%
New York	10%	1%	5%	14%	70%	59%	88%	3%	2%	2%	6%	24%
Ohio	24%	5%	11%	17%	44%	42%	42%	5%	11%	9%	33%	30%
Oklahoma	12%	2%	4%	10%	72%	57%	43%	6%	11%	9%	30%	39%
Oregon	18%	1%	1%	1%	80%	87%	63%	3%	2%	3%	28%	26%
Pennsylvania	19%	6%	11%	18%	46%	47%	47%	3%	13%	7%	30%	42%
South Carolina	22%	3%	8%	20%	47%	52%	45%	5%	10%	19%	22%	44%
South Dakota	4%	0%	4%	12%	79%	60%	23%	2%	22%	17%	36%	42%
Tennessee	8%	1%	6%	18%	67%	55%	48%	1%	14%	11%	26%	45%
Texas	10%	1%	2%	7%	79%	68%	17%	10%	12%	10%	51%	41%
Utah	6%	1%	2%	7%	85%	75%	8%	16%	12%	16%	48%	37%
Virginia	32%	7%	8%	15%	38%	40%	64%	4%	8%	6%	17%	38%
Washington	23%	1%	2%	2%	72%	71%	43%	3%	7%	11%	37%	40%
Wisconsin	23%	5%	13%	22%	37%	40%	21%	6%	13%	20%	41%	43%
West Virginia	28%	4%	7%	13%	48%	45%	29%	3%	12%	12%	44%	53%
Wyoming	7%	1%	3%	6%	83%	70%	9%	4%	11%	13%	63%	55%

EXHIBIT 21: AVERAGE NUMBER OF STARTS & AVG. OUTAGE LENGTH BY STATE – 2008 VS. 2018

	2008					2018				
	Hot Start (< 12h)	Warm Start (12 - 48h)	Cold Start (48 - 120h)	LT Outage (> 120h)	Avg. Outage Length	Hot Start (< 12h)	Warm Start (12 - 48h)	Cold Start (48 - 120h)	LT Outage (> 120h)	Avg. Outage Length
US Total	**3.7**	**3.1**	**3.4**	**2.5**	**148.3**	**2.0**	**1.7**	**2.8**	**4.1**	**341.9**
Alabama	3.2	2.5	1.5	2.0	147.6	2.7	0.8	1.5	3.5	407.5
Arkansas	2.8	0.8	2.2	2.0	186.8	1.1	1.4	0.4	2.1	542.0
Arizona	4.0	1.5	2.5	0.8	76.8	2.4	1.0	3.1	2.5	170.2
Colorado	2.3	1.6	2.3	1.5	140.7	2.1	0.7	1.0	2.3	372.7
Connecticut	5.0	5.0	3.0	1.0	47.2	3.0	-	2.0	9.0	532.8
Delaware	2.3	3.7	5.0	3.3	114.0	2.0	3.0	7.0	10.0	339.5
Florida	3.9	2.9	2.0	2.5	180.3	2.7	1.6	2.2	3.8	303.7
Georgia	1.9	2.5	1.1	1.6	160.2	1.7	1.4	1.6	2.9	870.1
Iowa	3.8	1.9	3.6	2.3	183.7	2.2	3.5	3.6	3.0	402.1
Illinois	2.7	3.6	3.4	2.1	122.6	2.3	2.9	5.0	4.8	176.4
Indiana	2.9	3.6	3.7	2.6	131.7	1.6	2.0	3.2	4.4	262.3
Kansas	2.8	3.7	2.3	1.1	129.0	1.1	1.7	5.1	3.6	242.6
Kentucky	3.0	4.2	2.7	1.5	120.1	1.7	1.6	2.4	3.6	258.8
Louisiana	2.8	3.3	1.8	1.8	114.1	1.3	2.1	2.6	4.3	268.6
Maryland	7.1	4.4	4.7	3.3	131.8	0.9	0.2	2.6	10.6	536.6
Michigan	2.5	2.8	5.0	2.2	156.9	1.5	0.8	1.3	4.1	597.0
Minnesota	2.5	3.7	3.7	2.5	167.0	2.6	3.9	4.4	4.3	126.8
Missouri	2.9	2.8	2.3	1.7	138.8	1.9	1.9	3.3	3.3	199.8
Mississippi	2.8	1.2	1.0	2.0	296.9	4.0	1.7	1.0	4.7	758.6
Montana	5.0	3.3	1.7	2.4	84.1	3.0	1.7	4.0	2.7	267.3
North Carolina	4.8	5.0	6.0	5.0	145.7	1.1	0.8	3.2	7.1	473.3
North Dakota	2.0	3.2	2.6	1.0	126.7	1.1	2.6	3.2	2.0	131.0
Nebraska	2.5	1.2	1.6	1.7	145.4	1.7	1.6	1.9	3.1	207.1
New Hampshire	1.0	1.2	2.8	2.0	174.3	12.0	5.8	6.0	11.0	221.5
New Jersey	1.9	5.1	6.4	6.0	301.5	3.0	-	-	4.0	1,229.3
New Mexico	6.6	2.5	4.2	1.5	88.4	2.4	3.4	2.8	2.6	280.7
Nevada	6.0	3.0	5.5	2.3	106.2	5.0	1.3	-	2.0	391.4
New York	2.2	1.4	2.5	1.8	127.4	1.5	0.5	3.0	7.5	622.7
Ohio	7.0	3.2	5.2	3.5	234.0	1.3	2.3	4.9	5.9	287.8
Oklahoma	5.0	2.2	2.2	1.8	105.9	3.5	2.7	5.3	8.7	217.6
Oregon	4.0	3.0	3.0	1.0	143.6	1.0	1.0	2.0	4.0	694.4
Pennsylvania	2.0	2.8	3.7	3.6	134.0	1.6	1.1	2.7	6.8	502.4
South Carolina	2.3	3.8	2.7	2.8	176.0	1.0	1.5	3.2	6.2	495.9
South Dakota	-	4.0	1.0	1.0	66.3	1.0	3.0	2.0	2.0	253.5
Tennessee	0.5	0.8	2.2	1.6	131.5	0.4	0.4	0.8	3.7	978.7
Texas	2.2	2.2	1.9	1.3	139.2	2.4	1.7	1.6	2.3	214.9
Utah	3.6	4.4	3.1	0.2	52.3	3.1	1.8	1.5	1.4	111.7
Virginia	13.0	4.0	5.6	5.5	130.1	0.5	0.8	3.7	7.7	462.9
Washington	2.0	3.5	3.0	2.5	191.0	2.0	3.0	3.5	1.0	404.4
Wisconsin	9.8	3.0	3.3	3.3	171.3	1.1	1.6	2.1	3.3	226.3
West Virginia	1.9	4.0	5.2	4.3	165.6	1.0	2.1	4.1	4.3	253.5
Wyoming	4.7	4.0	2.4	0.6	65.9	4.0	2.7	2.2	1.1	88.7

EXHIBIT 22: AVERAGE DISTRIBUTION OF HOURLY RAMP RATES BY STATE – 2008 VS. 2018

	2008			2018		
	No Ramping	< 2.5%	> 2.5%	No Ramping	< 2.5%	> 2.5%
US Total	**33%**	**39%**	**28%**	**32%**	**38%**	**30%**
Alabama	37%	37%	26%	49%	27%	24%
Arkansas	24%	43%	33%	20%	42%	38%
Arizona	44%	37%	19%	37%	27%	35%
Colorado	48%	39%	14%	32%	39%	30%
Connecticut	68%	14%	18%	19%	32%	49%
Delaware	47%	24%	28%	33%	24%	43%
Florida	31%	39%	29%	41%	29%	29%
Georgia	30%	35%	35%	39%	32%	29%
Iowa	35%	34%	31%	29%	38%	33%
Illinois	25%	43%	31%	30%	41%	29%
Indiana	30%	43%	27%	32%	36%	32%
Kansas	39%	40%	21%	16%	46%	38%
Kentucky	32%	40%	28%	32%	38%	29%
Louisiana	22%	57%	21%	19%	49%	32%
Maryland	18%	35%	48%	28%	31%	41%
Michigan	45%	32%	23%	44%	31%	24%
Minnesota	40%	36%	24%	27%	38%	35%
Missouri	38%	40%	22%	24%	46%	30%
Mississippi	30%	44%	26%	46%	27%	27%
Montana	48%	43%	9%	43%	36%	21%
North Carolina	39%	27%	34%	29%	32%	39%
North Dakota	35%	53%	12%	36%	50%	14%
Nebraska	40%	37%	23%	27%	40%	33%
New Hampshire	64%	28%	8%	46%	22%	32%
New Jersey	33%	35%	31%	20%	32%	48%
New Mexico	40%	45%	14%	28%	47%	25%
Nevada	38%	47%	15%	48%	27%	25%
New York	38%	39%	23%	24%	35%	41%
Ohio	24%	38%	38%	37%	40%	22%
Oklahoma	30%	56%	13%	24%	34%	42%
Oregon	32%	65%	3%	30%	46%	24%
Pennsylvania	26%	38%	37%	32%	40%	28%
South Carolina	33%	38%	29%	22%	44%	34%
South Dakota	22%	52%	26%	11%	39%	50%
Tennessee	40%	39%	21%	43%	35%	22%
Texas	27%	52%	20%	21%	45%	34%
Utah	35%	52%	13%	23%	38%	38%
Virginia	24%	31%	45%	34%	37%	29%
Washington	22%	70%	7%	19%	59%	21%
Wisconsin	34%	30%	36%	31%	36%	33%
West Virginia	25%	37%	38%	27%	43%	30%
Wyoming	31%	59%	9%	35%	39%	25%


NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS
DEDICATED TO PUBLIC SERVICE
1889

From: Marie Fagan
To: Christopher, Mahila
Cc: Windle, Rodney
Subject: RE: Draft AEP Ohio OVEC Audit
Date: Tuesday, September 8, 2020 3:42:14 PM
Attachments: Image001.png
Image002.png
Image003.png
Image004.png
Image005.png
Image007.png

Okay, thanks v much for the head start

From: mahila.christopher@puco.ohio.gov <mahila.christopher@puco.ohio.gov>
Sent: Tuesday, September 8, 2020 2:59 PM
To: Marie Fagan <marie@londoneconomics.com>
Cc: rodney.windle@puco.ohio.gov
Subject: RE: Draft AEP Ohio OVEC Audit

Hi Marie,
Please find attached Staff's initial comments on LEI's latest draft of the AEP Ohio, 2018-2019 PPA rider auditfinal report. This may help you get a head start on Staff's editorial suggestions. The comments can be discussed further at tomorrow's meeting.

**If you could please note that Staff still needs final acquiescence from PUCO Admin. regarding the overall tone of the draft report!

Staff's main observation regarding the tone of the draft is the following:
•Milder tone and intensity of language would be recommended such as the language on page 10, para 3: "Therefore, keeping the plants running does not seem to be in the best interests of the ratepayers."
•Reduced subjectivity and level of detail/specifics would be required such as the language on page 26, para 2: "HB 6 also provides subsidies for two large nuclear power plants in Ohio, and for that reason is the center of a federal bribery investigation. First Energy Corporation and the company's political action committee, and Generation Now, a 501 (c) (4) non-profit group are charged with paying $60 million to advocate for the passage of HB 6. The case has led to federal charges against Ohio House Speaker Larry Householder and four associates."

I am attaching a redlined Word version of the draft for your perusal/review. If you could, please take a look and incorporate Staff's comments as far as possible? Please let me know of any questions, comments, and concerns.

Thank you

Mahila Christopher
Public Utilities Commission of Ohio
Office of the Federal Energy Advocate
Utility Specialist
(614) 728-6954
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From: Christopher, Mahila
Sent: Tuesday, September 8, 2020 1:09 PM
To: Marie Fagan <marie@londoneconomics.com>
Cc: Windle, Rodney <rodney.windle@puco.ohio.gov>
Subject: RE: Draft AEP Ohio OVEC Audit

Hi Marie-
As per the RFP, the Final Report is due to be filed on the 16th of September:

1. Audit Proposals Due February 28, 2020
2. Award Audit March 11, 2020
3. Audit Conducted March 11, 2020 through September 1,
4. 2020 Draft Audit Report Presented to Staff September 1, 2020
5. Final Audit Report Filed with Commission September 16, 2020

Should Staff reach our edits to LEI by 2:00pm today, would it be possible for LEI to send an updated draft to the Company tomorrow?

Thank you

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From: Marie Fagan <marie@londoneconomics.com>
Sent: Tuesday, September 8, 2020 12:29 PM
To: Christopher, Mahila <mahila.christopher@puco.ohio.gov>
Cc: Windle, Rodney <rodney.windle@puco.ohio.gov>
Subject: RE: Draft AEP Ohio OVEC Audit

Okay, will do. Once we have your comments I'll have a good idea of how long it will take to address them, but I would guess we can complete it by the end of the week in any case, and likely sooner than that. So that means we can get the draft to Ed by this Friday 11th or maybe a day or so sooner, at least in electronic format. I think that the week that Ed wants for AEP Ohio review is reasonable, which means that they would get their review back to us by about Sept 18.th We would then address their comments (again, that should take a day or so, unless comments are extensive). Then we would provide you with the final report including workpapers the week of Sept. 21.
Best,
Marie

From: mahila.christopher@puco.ohio.gov <mahila.christopher@puco.ohio.gov>
Sent: Tuesday, September 8, 2020 9:32 AM

To: Marie Fagan <marie@londoneconomics.com>
Cc: rodney.windle@puco.ohio.gov
Subject: FW: Draft AEP Ohio OVEC Audit
Importance: High

Hi Marie,
Staff should be able to communicate our comments on the draft by tomorrow's meeting.
If you could, please assess Edward's question based on this and let me know if you have any concerns with his request for a week to review the draft for confidentiality and factual inaccuracies?

Thank you

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From: Edward J Locigno <ejlocigno@aep.com>
Sent: Tuesday, September 8, 2020 9:19 AM
To: Marie Fagan <marie@londoneconomics.com>
Cc: Andrea E Moore <aemoore@aep.com>; Christopher, Mahila <mahila.christopher@puco.ohio.gov>; Sheli A Sloan <sasloan@aep.com>; Steven T Nourse <stnourse@aep.com>
Subject: RE: Draft AEP Ohio OVEC Audit
Importance: High

Mahila/Marie

When can we expect the report to review for confidentiality and factual inaccuracies? We need a solid week really at least to review it. Please let me know. Thank you!

AMERICAN ELECTRIC POWER
EDWARD J LOCIGNO | REGULATORY ANALYSIS & CASE MGR
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1 RIVERSIDE PLAZA, COLUMBUS, OH 43215

From: Marie Fagan <marie@londoneconomics.com>
Sent: Wednesday, September 2, 2020 3:09 PM
To: Edward J Locigno <ejlocigno@aep.com>
Cc: Andrea E Moore <aemoore@aep.com>
Subject: [EXTERNAL] Draft AEP Ohio OVEC Audit

Dear Ed,
This is to confirm that LEI provided the draft OVEC audit report to the Commission Staff. The process now, as I understand it, is that Staff will review, and after that we will provide it to AEP Ohio for redacting. At that time, we can talk about a secure way to provide it to you, perhaps uploading to the data room.
Thank you for all your help with the audit.
Best,
Marie

LE
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From: Christopher, Mahila
To: Marie Fagan
Cc: Windle, Rodney
Subject: RE: an edit needed for AEP Ohio OVEC final audit report
Date: Friday, September 11, 2020 1:58:00 PM
Attachments: image003.png
image002.png
image004.png
image005.png
image006.png

Hi Marie,
Thank you for the heads up. Staff would recommend that you share this proposed edit with the Company as well.

Let me know if you have any questions.

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From: Marie Fagan <marie@londoneconomics.com>
Sent: Friday, September 11, 2020 12:17 PM
To: Christopher, Mahila <mahila.christopher@puco.ohio.gov>
Cc: Windle, Rodney <rodney.windle@puco.ohio.gov>
Subject: an edit needed for AEP Ohio OVEC final audit report

Hi Mahila,
I just realized there was an edit I wanted to make to page 10, where we said "However, LEI's analysis shows that the OVEC contract overall is not in the best interest of AEP Ohio ratepayers." that I missed in the last version of the report. I'll edit it when we get the version back from AEP Ohio next week-- I'll delete that sentence and tinker with the rest of the paragraph so it reads smoothly.
Best,
Marie

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11/12/2021 4:46:42 PM

in

Case No(s). 18-1004-EL-RDR, 18-1759-EL-RDR

Summary: Comments Initial Comments to Protect Consumers From AEP's Coal Plant Charges by Office of the Ohio Consumers' Counsel electronically filed by Ms. Deb J. Bingham on behalf of Finnigan, John